Consideration of Comments on 1st Draft FAC-003-2 Vegetation Management SDT — Project 2007-07

The Vegetation Management Standard Drafting Team (VM SDT) thanks all commenters who submitted comments on the 1st draft of FAC-003-2 — Transmission Vegetation Management Program standard. This standard was posted for a 30-day public comment period from October 27, 2008 through November 25, 2008. Stakeholders were asked to provide feedback on the standard through a special Standard Comment Form. There were more than 60 sets of comments, including comments from more than 100 different people from over 60 companies representing each of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Vegetation-Management_Project_2007-7.html

Key differences between first posting and second posting of proposed FAC-003 -2 include:

- Replaced the CCZ concept found in R4 with a practical field measurement to address commenter's concerns.
- Eliminated the CCZ as the trigger of imminent threat in R2 to address commenter's concerns.
- Added a sub part to the TVMP (1.6) in order to address commenter's concerns regarding the elimination of Clearance 1. This change requires that the TO account for anticipated conductor movement.
- Developed VRF's and VSL's consistent with the NERC Drafting Team Guidelines.
- Created a second grow-in outage requirement to allow for different VRF levels based on the actual criticality of the line.

There were 3 strong minority views not resolved:

- Some commenters disagreed with the "zero tolerance" nature of the existing in-force standard.
- Some commenters disagreed with a minimum Vegetation Inspection frequency of one year.
- Some commenters want to retain Clearance 1 that is in the existing in-force standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — Transmission Owners, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	John Neagle	Associated Electric Cooperative Inc.	✓				✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Bolick		SERC	1, 5, 6
2.	John Bussman		SERC	1, 5, 6
3.	Ralph Schulte		SERC	1, 5, 6
4.	Ted Hilmes		SERC	1, 5, 6
5.	John Settle		SERC	1, 5, 6
6.	Kevin White		SERC	1, 5, 6
7.	John Stickley		SERC	1, 5, 6
8.	Gary Highfill		SERC	1, 5, 6
9.	Jeff Neas		SERC	1, 5, 6
10.	Craig Thomas		SERC	1, 5, 6

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
2.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	Segment Selection

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Ralph Rufrano	New York Powerm Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Rick White	Northeast Utilities	NPCC	1
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidate Edison Co. of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
13.	Mike Gildea	Constellation Energy	NPCC	6
14.	Lee Pedowicz	NPCC	NPCC	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Linda Perez	WECC Reliability Coordination										
4.	Jerry Paulson	Western Area Power Administration, Upper Great Plains Region										
5.	Jack Gardner (Chairman) Joe Spencer (SERC staff)	SERC Vegetation Management Subcommittee (VMS)										

	Additional Member	Additional Organization	Region	Segment Selection
1.	**Jack Gardner**	**Progress Energy Carolinas**	**SERC**	
2.	**Randy Gann**	**Alabama Power Co.**	**SERC**	
3.	**John Neagle**	**Associated Electric Cooperative, Inc.**	**SERC**	
4.	**Robby Trimble**	**E.ON U.S. Services Inc. for LG&E & KU Companies**	**SERC**	
5.	**Ralph Hale**	**Entergy**	**SERC**	
6.	**Marc Tunstall**	**Fayetteville Public Works Commission**	**SERC**	
7.	**Reggie Wallace**	**Fayetteville Public Works Commission**	**SERC**	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region
8.	Jerry Lindler	South Carolina Electric and Gas Company	SERC
9.	Richard Dearman	Tennessee Valley Authority	SERC
10.	Billy George	Duke Energy Carolinas	SERC

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	John Pinney	Progress Energy Florida	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Crews		FRCC	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Michael Gammon	Kansas City Power & Light	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Todd Fridley		SPP	1, 3, 5
2.	Paul Beaulieu		SPP	1, 3, 5
3.	Duane Anstaett		SPP	1, 3, 5
4.	Gary O'Neil		SPP	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Ron Turley	Western Area Power Administration, Rocky Mountain Region	✓								✓	
9.	Jack Gardner	Progress Energy Carolinas	✓		✓		✓					
10.	Samuel Stonerock	Southern California Edison Company	✓		✓			✓				
11.	Jim Griffith	SERC OC Standards Review Group	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Case	Entergy	SERC	1, 3, 5
2.	John Neagle	Assoc. Electric Coop., Inc.	SERC	1, 3, 5
3.	Greg Rowland	Duke Energy-Carolinas	SERC	1, 3, 5
4.	Bill Thompson	Dominion Virginia Power	SERC	1, 3, 5
5.	John Rembold	Southern Illinois Power Coop.	SERC	1, 3, 5
6.	Jason Marshall	Midwest ISO	SERC	2

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
7.	Randy Castello	Mississippi Power Co.	SERC	1, 3, 5
8.	Jimmy Etheridge	Georgia Transmission Corp.	SERC	1
9.	Danny Dees	Municipal electric Authority of Ga.	SERC	1, 3, 5
10.	Glenn Stephens	South Carolina Public Service Auth.	SERC	1, 3, 5
11.	Glen Thweatt	Big Rivers Electric Coop.	SERC	1, 3, 5
12.	Gerald Beckerle	Ameren	SERC	1, 3, 5
13.	Sam Holeman	Duke Energy - Carolinas	RFC	1, 3, 5
14.	Melinda Montgomery	Entergy	SERC	1, 3, 5
15.	Roman Carter	Southern Company	SERC	1, 3, 5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Mike Neal	Western Utility Arborists	✓				✓				✓	
13.	John Tamsberg	Florida Power & Light	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eduardo Devarona	Florida Power & Light	FRCC	1
2.	Silvia Parada-Fortum	Florida Power & Light	FRCC	1
3.	Brian J. Murphy	Florida Power & Light	FRCC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Terry L. Blackwell	Santee Cooper	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Ben Fleming	Santee Cooper	SERC	1
3.	Kenny Sott	Santee Cooper	SERC	1
4.	Jim Peterson	Santee Cooper	SERC	1
5.	Glenn Stephens	Santee Cooper	SERC	1
6.	Kristi Boland	Santee Cooper	SERC	1
7.	Rene' Free	Santee Cooper	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Roman Carter	Southern Company	✓		✓							

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Steve Burns	Gulf Power Co.	SERC	3
2.	Nancy Huddleston	Georgia Power Co.	SERC	3
3.	Ronald Reinike	Mississippi Power Co.	SERC	3
4.	Randall Gann	Alabama Power Co.	SERC	3
5.	Marc Butts	Southern Co. Transmission	SERC	1
6.	Raymond Vice	Southern Co. Transmission	SERC	1
7.	JT Wood	Southern Company Transmission	SERC	1
8.	Jim Busbin	Southern Co. Transmission	SERC	1
9.	Chris Wilson	Southern Co. Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Charles Yeung	IRC Standards Review Committee		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	RFC	2
2.	Jim Castle	NYISO	NPCC	2
3.	Dan Rochester	IESO	NPCC	2
4.	Matt Goldberg	IEONE	NPCC	2
5.	Lourdes Estrada-Salinero	CAISO	WECC	2
6.	Anita Lee	AESO	WECC	2
7.	Steve Myers	ERCOT	ERCOT	2
8.	Bill Phillips	MISO	RFC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Brent Ingebrigtson	E.ON U.S.	✓		✓		✓	✓				
18.	Denise Koehn	Bonneville Power Administration	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Jamrog	Vegetation/Access Road Mgmt	WECC	1
2.	Jerry Reding	Transmission Engineering	WECC	1
3.	Don Swanson	Transmission Line Maintenance Technical Svcs	WECC	1
4.	Michael Staats	Transmission Engineering	WECC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Member	Organization	Region	Segment Selection
5.	Steven Bottemiller	Real Property Support Svcs	WECC	1
6.	Marian Wolcott	Real Property Svcs	WECC	1
7.	Jennifer Bailey	Transmission Line Maintenance Technical Svcs	WECC	1
8.	Stephen Larson	Legal	WECC	1
9.	Allen Chan	Legal	WECC	1
10	Robin Furrer	Transmission Field Services	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
19.	Jeffrey C. Mueller	Public Service Electric and Gas Company	✓		✓							
20.	Sam Ciccone	FirstEnergy	✓		✓	✓	✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Olenik	FE	RFC	1
2.	Shawn Standish	FE	RFC	1
3.	Rebecca Spach	FE	RFC	1
4.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21.	Joseph Knight	MRO NERC Standards Review Subcommittee	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Terry Harbour	MEC	MRO	1, 3, 5, 6
8.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
9.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
10.	Eric Ruskamp	LES	MRO	1, 3, 5, 6

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10
13.	Michael Brytowski	MRO	MRO	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22.	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8
2.	Greg Rowland	Duke Energy	SERC	1, 3, 5, 6
3.	Kirit Shah	Ameren	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	John Wolfmeyer	SERC Compliance Staff										✓
24.	JAMES W. SMITH	ITC HOLDINGS	✓									
25.	Richard Dearman	Tennessee Valley Authority	✓	✓	✓		✓				✓	
26.	Chris Scanlon	Exelon	✓		✓		✓		✓			
27.	Weston Davis	Central Maine Power Company	✓									
28.	Thad Ness	American Electric Power (AEP)	✓		✓		✓	✓				
29.	Deborah Schaneman	Platte River Power Authority	✓		✓		✓					
30.	Alan Gale	City of Tallahassee	✓		✓		✓					
31.	Fred Young	Northern California Power Agency (NCPA)				✓						
32.	Jason Lietz	Northern Indiana Public Service Company	✓									
33.	Chip Turner	Tampa Electric Company	✓		✓		✓					
34.	Edward Bedder	Orange and Rockland Utilities Inc.	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
35.	Jason Shaver	American Transmission Company	✓									
36.	Alice Druffel	Xcel Energy	✓		✓		✓	✓				
37.	Jeff Hackman	Ameren	✓		✓		✓	✓				
38.	John Humphrey	Nebraska Public Power District	✓									
39.	Jonathan Appelbaum	Long Island power Authority	✓									
40.	Robert (Bob) B. Suedkamp	USDA Forest Service, Southwestern Region, Regional Office for AZ and NM									✓	
41.	Kris Manchur	Manitoba Hydro	✓		✓		✓	✓				
42.	Jianmei Chai	Consumers Energy Company			✓	✓	✓					
43.	Dawn Travalini	National Grid	✓									
44.	Stephen Tankersley	Pacific Gas & Electric Co.	✓				✓					
45.	Rich Salgo	NV Energy (fka Sierra Pacific / Nevada Power Co.)	✓									
46.	Patricia vanMidde	San Diego Gas & Electric	✓		✓		✓					
47.	David Kiguel	Hydro One Networks Inc.	✓		✓							
48.	David Dworzak	Edison Electric Institute										
49.	George Czerniewski	Consolidated Edison Company of New York (CECONY)	✓									
50.	Tom Mathews and Steve Rueckert	WECC										✓

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
51.	Sreenath Thota	Arizona Public Service Company	✓	✓	✓	✓	✓	✓	✓	✓		
52.	Patrick Brown	PJM Interconnection		✓								
53.	William T. Rees	Baltimore Gas & Electric Company	✓									
54.	Greg Rowland	Duke Energy Corporation	✓		✓		✓	✓				
55.	Michael Pakeltis	CenterPoint Energy	✓									
56.	Ed Davis	Entergy Services	✓		✓		✓	✓				
57.	Anita Lee	Alberta Electric System Operator		✓								
58.	Richard Kafka	Pepco Holdings, Inc	✓		✓		✓	✓				
59.	Virginia Cook and Kim Wheeler	JEA	✓		✓		✓					
60.	Dan Rochester	Independent Electricity System Operator		✓								
61.	Karen Powell	Salt River Project	✓		✓		✓	✓				
62.	Rick White	Northeast Utilities	✓									
63.	Roger Champagne	Hydro-Québec TransEnergie (HQT)	✓									
64.	Kevin Koloini	Buckeye Power, Inc.			✓	✓	✓					
65.	Joe Knight	Great River Energy	✓		✓		✓	✓				

1. In the Purpose Statement the term “electric transmission systems” was changed to Bulk Electric System, and the Purpose statement was shortened by moving the various explanatory objectives to other locations in the revised Standard. Do you agree with the purpose statement? If not, please explain.

Summary Consideration: The SDT revised the purpose statement based on industry comments. The SDT returned to “electric transmission system” based on the comments that indicated confusion with the use of “BES”. The SDT also inserted the word “those” in front of the phrase “vegetation-related outages” to clarify that not all vegetation-related outages lead to cascading. The revised purpose statement now reads:

Purpose: To improve the reliability of the electric transmission system by preventing those vegetation related outages that could lead to Cascading.

Organization	Agree?	Question 1 Comment
Associated Electric Cooperative Inc.	Disagree	The definition of Bulk Electric System includes most transmission lines operated at 100 kv and above. While Section A.4.2.1 limits the applicability of FAC-003-2 to 200 kv and higher transmission lines, the use of the term Bulk Electric System could cause unnecessary confusion. Associated Electric Cooperative Inc recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by “BES” and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Florida	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment Based on the comments received, the SDT understands there may be confusion caused by “BES”		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
Kansas City Power & Light	Disagree	The definition of the bulk electric system does not match the scope of the systems covered by the vegetation management standard. If the term bulk electric system is used , it should exclude the areas not covered by the standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Use of the general term Bulk Electrical System creates unintentional confusion regarding the applicability of this standard to lines operated at 200 kV or higher and designated lines operated below 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Progress Energy Carolinas	Disagree	The intent of the revision of the standard was to bring clarity to the standard. Referring to the BES in the purpose creates confusion as to the applicability of the standard. Therefore, Progress Energy recommends the continued use of the term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC OC Standards Review Group	Disagree	The following comments are supplied by the SERC OC Standards Review Group (OCSRG): The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load. The current standard covers all 200 kV and above transmission lines along with those lower voltage lines designated by the RRO while the BES includes all lines 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, the SERC OCSRG recommends the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Florida Power & Light	Disagree	The Purpose Statement of any regulation or standard should be completely consistent with the body of regulation or standard. Here the use of Bulk Electric System (which is defined as 100 kV and above) is inconsistent with the language of the Standard that states this Standard applies to 200 kV and above. One of the primary purposes of re-

Organization	Agree?	Question 1 Comment
		drafting a Reliability Standard is to clear up any previous confusion -- here the Purpose Statement instead of adding to clarity, adds an unnecessary element of confusion. Thus, the Purpose Statement should be re-written to state 200 Kv and above.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES". Rather than create a new class of BES (>200kv), the SDT revised the purpose statement to delete BES and return to electric transmission system.		
Southern Company	Disagree	The initial FAC-003-1 drafting team had a particular reason for not using Bulk Electric System for fear of it being widely recognized to characterize the entire networked transmission system. This reason was to limit possible confusion with the applicability of the Standard. The Bulk Electric System definition includes all lines of the grid operated at 100 kV and above. This term also does not necessarily include lines of any voltage class that are radial and directly serving load. Use of this term in lieu of "electric transmission systems" has the potential to cause additional confusion to the industry.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
E.ON U.S.	Disagree	The definition of the Bulk Electric System generally does not include radial transmission lines directly serving load and, in addition, includes all lines operated at 100 kV and above. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
MRO NERC Standards Review Subcommittee	Disagree	The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	By definition Bulk Electric System includes most facilities 100 to 200 kV. The previous version of this standard appropriately restricted the applicability of the standard to these facilities by requiring the Regional Reliability Organization to identify only those facilities that are critical in this voltage class. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe to have one requirement of the standard say that it applies to all the BES and then another requirement to limit the

Organization	Agree?	Question 1 Comment
		application only confuses the applicability and recommend leaving the term "electric transmission systems" in the definition.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
SERC Compliance Staff	Disagree	The definition of the Bulk Electric System generally includes all lines operated at 100 kV and above and may exclude radial lines to load only. The standard is applicable to lines operated at greater than 200 kV regardless of their function. SERC staff does not believe that it is the intent of the standard to address lines operated at less than 200 kV unless they are deemed to be critical to the operation of the BES nor do we believe it is the intent to exclude radials to load only from the applicability. Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. Therefore, we recommend the continued use of the undefined term "electric transmission systems."
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
ITC HOLDINGS	Disagree	ITC does not agree with the new purpose statement. The NERC Glossary of terms states that the BES ?.generally operated at voltages of 100kV or higher and the Applicability in Section 4 clearly states the standard is intended to apply to all line voltages of 200kV and above and those lines designated by the Reliability Coordinator (4.2.1) as being subjected to this standard. Using the term Bulk Electric System (BES) clearly sends a confusing message and should be eliminated. Thus the term of "electric transmission system" is appropriate for the standard
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Tennessee Valley Authority	Disagree	TVA feels the use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this standard. TVA recommends the continued use of the undefined term "electric transmission systems. TVA recommends changing the phrase "by preventing vegetation-related outages that could lead to Cascading" to "by preventing those vegetation-related outages that could lead to Cascading", this removes the improper inference that each vegetation-related outage leads to Cascading
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word "those" to define that the standard should address interconnection reliability and security.		

Organization	Agree?	Question 1 Comment
Central Maine Power Company	Disagree	Central Maine Power suggests that a definition be provided for Bulk Power.
Response: The SDT is uncertain of the need to define Bulk Power.		
American Electric Power (AEP)	Disagree	American Electric Power ("AEP") does not agree with this purpose statement. First, it is clear from the Applicability (in Section 4) that the standard applies only to certain lines, not to the entire Bulk Electric System (BES). Reference to the BES in the Purpose statement tends to muddy the water, potentially leading to an assumption that the Standard indeed applies to the entire BES. AEP suggests that the term BES used herein be replaced with "electric transmission system" or "transmission grid". Second, the phrase "by preventing vegetation-related outages that could lead to Cascading" should be changed to "by preventing those vegetation-related outages that could lead to Cascading", to remove any suggestion that all vegetation-related outages could lead to Cascading.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. Additionally, at your suggestion and that of others, the SDT has added the qualifying word "those" to define that the standard should address interconnection reliability and security.		
Tampa Electric Company	Disagree	NERC glossary of terms defines the Bulk Electric System as "the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher." This, at a minimum, could lead to confusion over what impacts the reliability of the Grid by potentially including facilities less than 200 kV.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Orange and Rockland Utilities Inc.	Disagree	The use of the term "Bulk Electric System" (BES) could lead to confusion. In most regions BES includes lines with operating voltages equal to or greater than 100kV. The Standard is intended to apply to all lines with operating voltages equal to or greater than 200kV, and only those sub-200kV lines which are designated by the Reliability Coordinator (paragraph 4.2.1). Use of the words "electric transmission systems" rather than BES would eliminate this potential source of confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
American Transmission	Disagree	ATC disagrees with changing the term "electric transmission systems" to "Bulk Electric System". This standard applies to 200 kV and higher transmission lines not all BES facilities. Suggested Purpose statement: To maintain

Organization	Agree?	Question 1 Comment
Company		the reliability of the electric transmission system by requiring entities to have and implement a transmission vegetation management plan.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system. We also appreciate your suggested purpose statement but based on others' comments to be more specific about the reliability need for this standard we modified the purpose statement as seen in the Summary Consideration above.		
Ameren	Disagree	By definition, the capitalized term, Bulk Electric System, is defined to include most facilities 100 kV and above. The previous version of this standard appropriately restricted the applicability of the standard to those facilities operating above 200kV and any additional facilities identified by the Regional Reliability Organization as critical. This new version of the standards attempts to limit the 100-200 kV class applicability by having the RC identify the critical facilities. We believe the change creates unnecessary and undesirable confusion in that one requirement of the standard says that it applies to all the BES and then another requirement limits the application. Leaving the term "electric transmission systems" in the definition is preferable to that proposed.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Nebraska Public Power District	Disagree	NPPD disagrees with the change to bulk electric system, because it creates confusion on the applicability. This standard only applies to certain lines and not the entire (bulk) system.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Manitoba Hydro	Disagree	Manitoba Hydro disagrees with changing "electric transmission systems" to "Bulk Electric System" because BES applies to facilities 100kV and above which may not have an impact on system reliability.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Consumers Energy Company	Disagree	Consumers Energy disagrees with changing the current "electric transmission systems" to "bulk electric system". This change will create confusion and can lead to a discrepancy concerning lines operating below 200kV that may be included in the "bulk electric system" but are otherwise excluded from this standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES"		

Organization	Agree?	Question 1 Comment
and has revised the purpose statement to delete BES and return to electric transmission system.		
National Grid	Disagree	Use of the term Bulk Electric System will cause unnecessary confusion to the industry concerning applicability of this Standard.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Edison Electric Institute	Disagree	The purpose of the standard should be revised to state 'To maintain minimum clearances sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions.' This is the identical wording taken from Order No. 693, Paragraph 731.
Response: The SDT appreciates your comments to use the exact wording in the FERC Order for the purpose statement. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Consolidated Edison Company of New York (CECONY)	Disagree	The phrase "Bulk Electric System" (BES) is somewhat misleading. BES includes transmission voltages greater than 100kV but this Standard addresses transmission lines with operating voltages at or above 200kV and only those lines below 200kV designated by the Reliability Coordinator. Use of the phrase "electric transmission circuits" or something similar rather than BES would reduce confusion.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Arizona Public Service Company	Disagree	APS suggest the following change; To improve the reliability of the Bulk Electric System by preventing vegetation related outages. This is a reliability standard APS would suggest removing "that could lead to widespread cascading failures" from the purpose statement.
Response: The SDT thanks you for your comment. However, the SDT believes strongly that the interconnected system reliability which FERC should be protecting is better defined by the second posting statement. For instance, there are 200 kV circuits which serve only local load. Outages to these circuits from vegetation are no different than from other causes. The issue for this standard should be the prevention of vegetation outages that will threaten the interconnection.		
Duke Energy Corporation	Disagree	Duke disagrees with changing "electric transmission systems" to "Bulk Electric System" because this creates the potential for confusion or indiscriminate expansion of the scope of applicability to 100kV facilities which may not

Organization	Agree?	Question 1 Comment
		have an impact on network system reliability. Using "Bulk Electric System" confuses the applicability of the standard. Duke believes that Section 4.2 has the specificity to clearly designate any applicable lines. Thus, the term "electric transmission systems" is appropriate.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Entergy Services	Disagree	Entergy disagrees with changing "electric transmission systems" to "Bulk Electric System." Historically, the definition of the Bulk Electric System has included all lines operated at voltages 100 kV and greater. The above change in terminology will add ambiguity to which lines this standard is applicable. Entergy is concerned about the potential for this ambiguity leading to the expansion of the applicability of the standard to include lines below 200kv.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
JEA	Disagree	We disagree with this change as it may cause confusion on the applicability of the standard as the BES is generally 100kV and above, but this standard generally applies to 200kV and above.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Great River Energy	Disagree	The standard specifically calls out that 200kV and higher are applicable to FAC-003. Changing to BES would imply all lines 100kV and above would be applicable
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system.		
Western Area Power Administration, Upper Great Plains Region	Agree	Western (UGPR) agrees with the objective of using the FERC/NERC defined term "Bulk Electric System", but believe that the FERC/NERC definition includes lines above 100 kV. It needs to be clearly understood that use of the generic term in the Purpose section does not supersede the specific definitions (greater than 200 kV, etc.) contained in the Facilities section.
Response: The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.		

Organization	Agree?	Question 1 Comment
Platte River Power Authority	Agree	The use of the approved terminology, Bulk Electric System, from the NERC Glossary of Terms is better than the undefined term electric transmission systems.
Response The SDT thanks you for your comment. Based on the comments received, the SDT understands there may be confusion caused by "BES" and has revised the purpose statement to delete BES and return to electric transmission system based on a overwhelming industry preference for the latter.		
Northeast Utilities	Agree	Agree with the term "bulk electric system. "Disagree with the wording of the Purpose Statement; The Purpose statement reads "To improve the reliability of the bulk electric system by preventing vegetation related outages that could lead to Cascading." One vegetation-caused outage does not in and of itself cause Cascading. Cascading will only result due to a combination of events - either multiple vegetation outages during the same time or an outage coupled with equipment malfunction or operational errors. The document seems to be internally inconsistent in this regard. The Technical Reference for FAC-003-2 notes that outages due to trees falling from outside the right-of-way or other outage causes on a critical facility would not constitute a possible cascading effect. If one occurrence of these types of outages would not constitute a cascading potential then one must wonder why an outage from a tree contact within the right-of-way is considered a possible cascading event? Suggest rewording the statement to exclude the comment about Cascading and use "by preventing vegetation related outages on critical transmission facilities."
Response: The SDT thanks you for your comment. The SDT acknowledges that a single vegetation-related outage will not, in the absence of other contributing factors cause a cascading collapse of the electric grid. The intent of the standard is to prevent those vegetation-related outages that could contribute to a cascading event. Therefore based on your comment, and others', the SDT added "those" to further refine the intent.		
Southern California Edison Company	Agree	Q1: SCE agrees in part with the proposed revisions to the purpose statement. However, we believe the phrase "vegetation related outages" is unnecessarily vague. Based on the content of certain requirements in Version 2, the intent of this standard is and should be to prevent sustained outages due to vegetation-to-line contacts. SCE respectfully suggests the purpose statement (A3) be revised to read: "To improve the reliability of the Bulk Electric System by preventing vegetation-to-line contacts that could lead to Cascading?
Response: The SDT thanks you for your comment. The SDT focuses this standard on preventing vegetation-related Sustained Outages rather than vegetation to line contacts as you recommend because not all contacts result in Sustained Outages.		
BCTC	Agree	Yes, we agree.
Western Utility Arborists	Agree	Yes, we agree.

Organization	Agree?	Question 1 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
Santee Cooper	Agree	
Exelon	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Xcel Energy	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	

Organization	Agree?	Question 1 Comment
NPCC	Agree	
WECC Reliability Coordination	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
CenterPoint Energy	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Response: The SDT thank you for your participation. The SDT made revisions to the purpose statement in response to industry comment. In order to avoid confusion the SDT replace "BES" with "electric transmission system" and inserted the word "those" in front of the phrase "vegetation-related outages".		

2. The Reliability Coordinator was chosen as the proper entity to identify sub-200kV transmission lines to be subject to this standard (see applicability, R9, and R10). Do you agree with this choice? If not, please explain.

Summary Consideration: A majority of the commenters agreed with the selection of Reliability Coordinator to designate sub-200 kV transmission lines to which this standard applies. However several dissenters recommended the Planning Coordinator (PC) as a more appropriate choice. The stakeholders' main reason for preferring the PC is the longer time horizon that the PC normally considers in the performance of its function. Typically an RC considers the real time to months ahead operating time horizons. A PC typically takes into account a planning horizon extending out several years. An example cited by some stakeholders is the assignment to the PC for identifying applicable lines in NERC Standard PRC-023 R3 – Transmission Relay Loadability.

Upon consideration of the sound rationale for replacement of RC with PC, the SDT changed Requirement R10 and R11 as well as the applicability section 4.2 to reflect this.

Some commenters suggested that facilities critical to the derivation of an IROL should be the only criterion for selection of lines subject to this standard. The Independent System Operator - Regional Transmission Owner Council (ISO/RTO Council) and individual ISOs offered that all transmission lines of the BES are applicable under this standard regardless of voltage class or impact on the BES. However the ISO/RTO Council believes that there are other standards that determine critical facilities. The SDT agreed that including facilities critical to the derivation of an IROL would be a technically acceptable threshold to determine applicability of sub-200 kV lines, but concluded that there are other thresholds that define circuits important to the reliability of the Bulk Electric System (e.g., the WECC region's Major Transfer Paths). The SDT wishes to allow the application of other criteria in addition to IROL to support to the greatest extent possible the reliability of the BES.

Several commenters recommended the inclusion of a dispute resolution process and coordination between Transmission Owner/RC in this standard to ensure agreement and consistency across regions. The SDT believes that the language in Requirement R10 which specifies "consultation" **OR CONSENSUS** between the Planning Coordinator and its member Transmission Owners, would minimize the need for a dispute resolution process. Additionally, other Standards in which the PC determines important circuits to the reliability of the BES include no such mechanism.

Requirements R9 and R10 (now R10 and R11) were changed as follows:

R9. Each Planning Coordinator shall prepare and review annually, a list lines that are operated below 200kV, if any, which are subject to this standard. . Each Planning Coordinator shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list.

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R10. Each Planning Coordinator shall develop and document its method for assessing the reliability significance of sub-200kV lines whose loss would place the grid at an unacceptable risk of instability, separation, or cascading failures.

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R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL)¶
R10.2 Transmission lines

Organization	Agree?	Question 2 Comment
SERC Vegetation Management Subcommittee (VMS)		The SERC Vegetation Management Subcommittee (VMS) abstains on this question. However, we believe that this comment form should provide an option to abstain in addition to the options to agree/disagree.
Response: Thank you for your comment. The SDT does not believe this issue can be addressed by this team. However it is appropriate to raise this limitation with the NERC staff.		
American Transmission Company	Disagree	Requirements 9 and 10 should be deleted and replaced with the following language. Proposed Language The Transmission Owner shall include those transmission lines below 200 kV that that are associated with an established IROL. (This language could either be uses as a requirement or inserted into the Applicability section.) Our statement provides a clear decision on which lower voltage lines have to be included in an entities transmission vegetation management program.
Response: Thank you for your comments. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11)as well as the applicability section 4.2. The SDT believes that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. The FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely IROL lines may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard which includes IROL calculations.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard.
Response: Thank you for your comment. The SDT agrees and has replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Santee Cooper	Disagree	The RC should not define applicable lines that are operated below 200 kV. PRC023 requires the Planning Coordinator to define transmission lines operated at 100 kV to 200 kV that are considered critical to the reliability of

Organization	Agree?	Question 2 Comment
		the Bulk Electric System. Multiple lists will lead to confusion among electric utilities.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Southern Company	Disagree	The use of the Reliability Coordinator as the entity for identifying sub-200 kV lines is inconsistent with the approach used in other NERC standards, such as PRC-023. Other NERC standards utilize the Planning Coordinator or the RRO as the entity. We feel the Planning Coordinator would be the appropriate entity for identifying sub-200 kV lines covered by FAC-003-2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG does not believe that the RC is the appropriate entity to identify sub-200 kV transmissions to be subject to this standard. Vegetation Management programs are longer than the normal operating horizons of RCs. We believe that the proper function to identify sub-200 kV transmission lines subject to this standard is the Planning Coordinator. This must be consistent with PRC-023, Requirement 3. We also recommend that a process be established for dispute resolution. NERC should develop a comprehensive approach to the determination of "critical" facilities rather than pushing a piecemeal approach as evidenced by this standard and PRC-023, among others.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed. **In regard to a comprehensive approach to identify/determine “critical” facilities, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that “one size can fit all” for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
IRC Standards Review Committee	Disagree	We do not see the role of an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and

Organization	Agree?	Question 2 Comment
		R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standard's applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Independent Electricity System Operator	Disagree	The IESO does not see a role for an RC or PC in a vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, particularly those that impact the BES. We are of the view that identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should therefore be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R9 and R10 (now R10 and R11). The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT believe that the Planning Coordinator (PC) should be the entity responsible to determine the elements part of the BPS submitted to this Standard, and in fact for all other Standards. Those elements should be determined by an impact based methodology, as used in NPCC, with no voltage limitation and no fixed voltage threshold level as imposed in Applicability 4.2.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirement R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The SDT believes each PC can determine the appropriate threshold to assure the reliability of the BES and does not believe it necessary to instruct PCs in this regard in this Standard.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. The MRO believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from these standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC. The SDT believes		

Organization	Agree?	Question 2 Comment
that further guidance is needed to ensure all regions have evaluated and developed a list of sub 200kV lines that are subject to this standard. FERC indicated that not all regions produced such lists and directed the ERO, using this stakeholder process, to develop a mechanism to provide the list. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs. In R10, the SDT believes that the PC has the requisite expertise and planning horizon perspective to designate sub 200kV lines to comply with this standard. Limiting the choice of lines to solely those included in the derivation of an IROL may not achieve the purpose of this standard. The SDT intends in R10 that the PC employ a technically sound criterion when designating transmission lines to be subject to this standard, which could include those included in the derivation of IROL calculations.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	We do not believe that the RC is the appropriate entity to identify those facilities sub-200 kV facilities that this standard should apply to. Vegetation management is not performed in the operating horizon. Rather it is performed in the planning and operations planning horizons. The RC should not be distracted from focusing on the operating horizon by this task. We believe what the standard is essentially requiring is identifying critical facilities. There are other similar requirements such as PRC-023-1 R3 that appear to require the determination of critical facilities even though the term critical facilities is not defined. We believe this represents broader issue that requires NERC to define critical facilities. Failure to do so could result in the inefficient identification of multiple lists of critical facilities for specific requirements that may ultimately be challenged in due process.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. Your comment on time horizon further supports this change. **In regard to a comprehensive approach to identify/determine circuits, the SDT agrees in concept but has some reservations. The reservations are based upon doubt that "one size can fit all" for every context of every standard. A critical facility for one situation may not be a critical facility for another. For example, the PRC standard seeks to identify facilities that may need to carry very heavy contingent flows to stop a cascade. This FAC-003 standard seeks to identify facilities for which their OUTAGE (due to vegetation) would create reliability concerns for the BES.**		
Ameren	Disagree	While the RC would seemingly have the wide area view to make the assignment appropriate, the standard is really trying to determine the entity who can assess the risk to the BES of a vegetation-related outage. The management of that risk is in the venue of the Transmission Planner who, in the long term, designs the system and, in the Operating Horizon, establishes the parameters of operation that will lead to reliability. Certainly, the RC is preferable to the RE (RRO). However, the TP is preferable to the RC.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC including a reference to NERC Standard PRC-023 Relay Loadability. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. The PC performs its function over a similarly long term time horizon as the Transmission Planner but would be better positioned as a result of the PC's wider area view.		

Organization	Agree?	Question 2 Comment
Manitoba Hydro	Disagree	Manitoba Hydro disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. Lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the revised draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list; there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by MH.**		
WECC	Disagree	WECC believes the Regional Entity should remain the proper entity to identify sub-200kV transmission lines subject to this standard. The Regional Entity is in the best position to work with Transmission Owners (Transmission Owners) and Reliability Coordinators across the interconnection to determine critical sub-200kV transmission lines.
Response: Thank you for your comments. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
PJM Interconnection	Disagree	The RC or PC should not play a role in the vegetation management standard. All Transmission Owners need to ensure they have a vegetation program to avoid unnecessary tripping of transmission lines, at any voltage levels and regardless of their impacts on the BES. Identification of critical facilities is not a part of this standard; it belongs to other standards that deal with SOL/IROL calculations, SPS, protection and critical infrastructure protection. R10 and R11 should be removed from the standard.
Response: Thank you for your comments. The SDT does not agree with removal of R10 and R11. The SDT does not believe the burden of compliance for low voltage circuits with little or no impact on the BES is reasonable for electricity consumers to bear. FERC has acknowledged the same and given guidance for this standards' applicability which provides that a distinction exists in sub-200 kV facilities. The SDT sought to develop a reasonable mechanism that balances these concerns when we drafted R10 and R11. The SDT agrees with respect to use of the label "critical". This standard does not intend to classify facilities as critical, that is left to CIP-002		
National Grid	Disagree	No opinion.
Response: Thank you for your participation.		

Organization	Agree?	Question 2 Comment
Duke Energy Corporation	Disagree	Duke believes that the Planning Coordinator is the appropriate entity to identify any sub-200 kV facilities that this standard should apply to. Of note is the time frame once a sub-200kV line is designated, then the Transmission Owner has 12 months before the line is subject to the standard. This coincides with the longer term view of the Planning Coordinator.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Great River Energy	Disagree	GRE disagrees that the RC is appropriately positioned to identify and designate any sub-200kV lines that should be subject to this standard. GRE believes that the lines below 200kV should include only those that are currently classified as Interconnection Reliability Operating Limit (IROL) lines which are already defined and listed for registered entities. As such R10 and R11 should be eliminated from this standards along with the RC in the applicability section.
Response: Thank you for your comments. The SDT agrees that the RC is not appropriately positioned and replaced the RC with the PC in the draft proposed Standard. **The SDT agrees that lines included in the derivation of an IROL should be included in the PC's list, there are other lines that have importance to the reliability of the BES, e.g. the WECC Major Transfer Paths. The PC is well qualified for this differentiation task and may choose to develop thresholds which match the needs of its region. Therefore, the SDT respectfully disagrees that the only sub-200 kV circuits for which this standard should apply are those stated by GRE.**		
WECC Reliability Coordination	Agree	This would be a new function in WECC RC; we are not currently staffed to perform this function.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Western Area Power Administration, Upper Great Plains Region	Agree	Western's (UGPR) agreement is contingent upon maintaining the requirements for consulting with Transmission Owners and neighboring Reliability Coordinator(s) and documenting the method for assessing the reliability significance of each included line as contained in R10 and R11.
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Florida	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.

Organization	Agree?	Question 2 Comment
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Kansas City Power & Light	Agree	I agree with the qualification that the Reliability Coordinator identify sub-200kv facilities in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s).
Response: Thank you for your comment. The SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
Progress Energy Carolinas	Agree	While Progress Energy agrees that the RC is the appropriate entity, the drafting team should consider including a dispute resolution requirement for those instances when the Transmission Owner and the Reliability Coordinator disagree as to which lines below 200 kV should be included.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this. In regard to dispute resolution process, the SDT believes that the requirement for consultation implies cooperation and collaboration between entities and a dispute resolution process is not currently needed.		
Southern California Edison Company	Agree	Q2: No comments.
Response: Thank you for your participation.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your comment. Please see the summary consideration – based on stakeholder comments, the SDT changed the applicability in Requirements R9 and R10 (now R10 and R11) from the Reliability Coordinator to the Planning Coordinator.		
ITC HOLDINGS	Agree	ITC agrees that the Reliability Coordinator is the appropriate entity to identify and designate any sub - 200kV lines deemed applicable to the standard with the concurrence of the Transmission Owner.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as		

Organization	Agree?	Question 2 Comment
neighboring PCs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment question 2
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		
American Electric Power (AEP)	Agree	AEP concurs with the drafting team that the Reliability Coordinator is the appropriate entity for identifying sub-200kV lines (if any) that would be subject to the Standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Platte River Power Authority	Agree	The Reliability Coordinator is better able to identify lines under 200 kv that would exceed an Interconnection Reliability Operating Limit (IROL), cause instability, uncontrolled separation, or cascading outages resulting from a vegetation related outage than the Regional Entity.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Nebraska Public Power District	Agree	NPPD agrees that the Reliability Coordinator is the correct body for identification of any sub 200kV lines that would be subject to this standard.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees provided that R10 remains the same as is currently written. This states that the Reliability Coordinator, in consultation with the Transmission Owner, shall jointly prepare and keep current, a list of designated applicable lines.
Response: Thank you for your comment. Based on other stakeholder comments, the SDT replaced RC with PC in Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2. The proposed R10 continues to require consultation between the PC and Transmission Owner as well as neighboring PCs.		

Organization	Agree?	Question 2 Comment
Northeast Utilities	Agree	One question: Will the Reliability Coordinators use consistent criteria for listing sub 200-kV facilities to be included under FAC-003-2? The purpose of FAC-003 is to ensure inter-regional reliability and to focus on the reliable operation of these lines. By leaving the decision up to the individual Reliability Coordinators - there is the potential for local differences in determining which sub-200-kV facilities may be critical. This could result in some transmission owners having to include certain facilities under the requirements of FAC-003-2 where in other regions of the country - similar facilities may not be included by the Reliability Coordinator. Although there have been criteria established to guide the Reliability Coordinators in the determination of sub-200-KV facilities for inclusion under FAC-003-2 - is this sufficient to ensure uniformity throughout the US? Perhaps some involvement at the Regional Entity level at least, is warranted.
Response: Thank you for your comments. The SDT agrees with the points you raise regarding inter-regional reliability. This is addressed in part by the requirement R10 where consultation with neighboring entities is specified. We feel that the requirement R10 ensures that inter-regional coordination is addressed. **In addition several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.**		
Baltimore Gas & Electric Company	Agree	The documented method to assess the reliability significance of sub-200 kV lines referenced in R10 should be put out for comment by the Reliability Coordinator to the regulated entities and FERC/NERC before it is finalized.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
Entergy Services	Agree	The applicability of this standard should state that it is not applicable to insulated transmission lines, such as underground lines.
Response: Thank you for your comment. The SDT believes that the general term "transmission line" along with the associated tables and terminology sufficiently eliminates any misconception or misdirected thought that this standard applies to underground conductors or other conductors that are insulated in a manner that would prevent their flashover to trees.		
Pepco Holdings, Inc	Agree	FERC Order 693 essentially has the RC replacing the RRO.
Response: Thank you for your comment. Several commenters offered sound rationale for replacement of RC with PC. The SDT agreed with the rationale and changed Requirements R9 and R10 (now R10 and R11) as well as the applicability section 4.2 to reflect this.		
BCTC	Agree	Yes, we agree.

Organization	Agree?	Question 2 Comment
Response: Thank you for your participation.		
Buckeye Power, Inc.	Agree	Agreed on this question.
Response: Thank you for your participation.		
Western Area Power Administration, Rocky Mountain Region	Agree	
Florida Power & Light	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities	Agree	

Organization	Agree?	Question 2 Comment
Inc.		
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Arizona Public Service Co.	Agree	
JEA	Agree	
CenterPoint Energy	Agree	
Salt River Project	Agree	

3. **In R1 the proposed standard replaces "prepare, and keep current" with "have", replaces the list of terms, "objectives, practices, approved procedures, and work specifications," with "designed to control vegetation", defines the "active transmission line ROW", and specifies that the transmission vegetation management program applies to that area. Do you agree with R1? If not, please explain.**

Summary Consideration:

Regarding the use of "have", some commenters requested that the original wording should remain. However, the SDT and some other commenters note that proving whether something is "current" is an opportunity for compliance ambiguity and unintended discrimination. Therefore, the SDT continues to use "have" in the second draft.

A few commenters raised the issue concerning Critical Clearance Zone in this question and that has been addressed with the substantive changes which have been made to the second draft standard.

While some commenters prefer the list of terms, the SDT chose the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. The SDT agrees the list of terms is helpful. However, when listed in a Requirement there is an expectation that all such terms must be included and evidence produced to show compliance. The list of terms can be included in the technical reference to assist Transmission Owners.

Finally, many commenters wanted more specificity in the reference material to describe the "Active Transmission Line Right-of-Way". The SDT has provided additional clarification in the technical reference document.

The revised R1 is shown below:

R1. Each Transmission Owner shall have a documented transmission vegetation management program that describes how it conducts work on its Active Transmission Line Rights of Way to prevent Sustained Outages due to vegetation, considering all possible locations the conductor may occupy under the effects of sag and sway throughout its operating range under rated conditions. The transmission vegetation management program shall:

1.1. Specify the methods that the Transmission Owner may use to control vegetation.

1.2. Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local[3] and environmental factors.

1.3. Require an annual plan. An annual work plan shall:

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1.3.1 Identify the applicable lines to be maintained

1.3.2 Identify the work to be performed

1.3.3 Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.

1.3.4 Take into consideration permitting and scheduling requirements from landowners or regulatory authorities.

1.4. Require a process or procedure for response to an imminent threat of a vegetation related Sustained Outage. The process or procedure shall specify actions which shall include immediate communication of the threat to the responsible control center.

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

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

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Organization	Agree?	Question 3 Comment
Bonneville Power Administration	Disagree	R1: BPA understands that version 2 clearly states that the Critical Clearance Zone does not extend beyond the Active Transmission Right of Way. The Technical reference provides examples of active and inactive portions o corridors. BPA feels this list of examples is not exhaustive and therefore the technical reference language shou be changed to read, "Examples of active and inactive portions of corridors include, BUT MAY NOT BE LIMITED Transmission Owner:" Also, since it is clearly stated on page 2 of the Standard, that the Critical Clearance Zone shall not extend beyond the limits of the Active Transmission Line Right of Way, and that these limits are not specifically defined because they may vary by circumstance, the definition of Active Transmission Line Right of Way on Page 2 of the Standard should include a statement that the actual physical limits of each Active Right of Way will be determined by the Transmission Owner. R1.1: BPA recommends retaining the version 1 language of "objectives, practices, approved procedures, and work specifications" as it is more instructive in what is expected of a TMVP then the version 2 replacement language of "methodologies."

Response: Thank you for your comment. The issues concerning Critical Clearance Zone have been addressed by changes which have been made to

Organization	Agree?	Question 3 Comment
the draft standard. The definition and use of the term "Critical Clearance Zone" have both been removed from the revised standard. **The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.**		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc agrees with the changes described in Question 3 except for the definition of Active Transmission Line Right of Way. Associated suggests the term be revised to "Active Right-of-Way" for consistency with the present Glossary term "Right-of-Way" and that the definition of Active Right-of-Way be revised to explicitly permit the Transmission Owner to solely determine the appropriate width. A suggested definition is "Active Right-of-Way: The portion of Right-of-Way utilized for active transmission facilities. The width of the Active Right-of-Way, as determined by the Transmission Owner, shall be consistent with the Transmission Owner's normal standards and practices and shall be consistent with good utility practice for other transmission lines of similar voltage and configuration. Inactive or unused portions of the Right-of-Way, intended for future transmission lines or other facilities, may be excluded from the Active Right-of-Way."
Response: Thank you for your comment. While there is logic in your proposal to simply modify Rights-of-Way with "Active", previous commenters wanted to include "Transmission" to clearly eliminate the case of rights-of-way that include lower voltage facilities.		
NPCC	Disagree	While we agree with the suggested changes, we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way. We recommend using the following phrase in R1: "designed to remove incompatible vegetation on its Active Transmission Lines' Rights 0f Way" instead of "designed to control vegetation on its Active Transmission Lines' Rights of Way ". Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone. This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner. Removal of incompatible vegetation is superior to pruning, topping, and trimming in terms of short and long term reliability of the Bulk Electric System. This language would also serve to align NERC and FERC with Transmission Owners who attempt achieve the highest degree of reliability by exercising their full easement rights in cases where strong opposition from landowners and public officials is encountered. If such language is adopted it should apply to R1 and the Transmission Vegetation Management Program. It should be made clear in the technical reference document that removal, rather than pruning of incompatible vegetation is the philosophy that must be incorporated into the Transmission Vegetation Management Program. It

Organization	Agree?	Question 3 Comment
		must be clearly explained that Transmission Owners have the flexibility to perform removals gradually over several treatment cycles in sensitive areas as long as pruning is performed as an interim measure to ensure that Critical Clearance Zone encroachments and on-Right of Way fall overs do not occur. It must also be made clear that the presence of incompatible vegetation on the Right of Way will always occur and does not in itself constitute a violation of the Standard.
Response: Thank you for your comment. The SDT has addressed removal of incompatible vegetation as a best management practice by referencing ANSI A300 as a footnote to Requirement R1. It is noted that A300 is not a requirement of the standard, only a best management practice. We will address your other comments in the technical reference paper for industry guidance.		
Baltimore Gas & Electric Company	Disagree	I agree with the simplification of the language, but I am uncomfortable with the definition of Active Right-of-Way (R/W). The definition in FAC-003-2 and the examples used in the white paper continue to leave room for interpretation, particularly with respect to the example where only one circuit is installed on a double circuit tower. Moreover, there may be circumstances where the Active R/W is relatively narrow and the utility has an Inactive R/W or otherwise owns land adjacent to the Active R/W that can be maintained to protect the facilities from grow-ins. Consequently, consideration should be given to require utilities to protect lines from grow-ins into the Critical Clearance Zone regardless of whether or not the R/W is Active or Inactive as long as the utility has the legal ability to do the necessary work.
Response: Thank you for your comment. The Standard clearly addresses that all grow-ins are considered to be within the active right-of-way, regardless of whether or not the tree is rooted within the active right-of-way. The Standard requires that such vegetation be managed as described in the Transmission Owner's Transmission Vegetation Management Program. Additionally, the SDT has revised the drawings and guidance in the technical reference paper to eliminate the confusion you and others detected.		
Northern Indiana Public Service Company	Disagree	Use of the term "have" is a notable and unnecessary weakening versus the terms "prepare and keep current". One of the key lessons learned from past vegetation related outages and subsequent investigations and reports is that successful UVM programs must continually adapt to changing circumstances which means practices and procedures must be kept current. Why weaken this expectation in the standard? Also, I disagree with the elimination from the revised standard the present requirement R1 that all Transmission Vegetation Management Programs include certain essential components (objectives, practices, approved procedures & work specifications). Why make changes that imply Transmission Vegetation Management Program's without these key components are acceptable?
Response: Thank you for your comment. The SDT believes that the term "have" is appropriate. While sympathetic to your perception about the terms, in order to "have" a Transmission Vegetation Management Program it had to have been prepared. Latency of the plan, like all plans required by NERC standards, can easily be addressed in compliance without creating the task of proving "current" if it is included in the Requirement. The SDT chose, for the revised standard, the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their		

Organization	Agree?	Question 3 Comment
Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Xcel Energy	Disagree	We propose adding the following language to the end of the definition for "Active Transmission Line Right of Way": OR OTHER PURPOSES, REGARDLESS OF THE PREMISES DIMENSIONS IN ANY EASEMENT, LICENSE AGREEMENT OR OTHER LAND RIGHT DOCUMENT.
Response: Thank you for your comment. The SDT believes that the definition of "active transmission line right-of-way" is appropriate for meeting the objectives of the Standard. This topic will be covered in the technical reference document which will be issued with the next draft of the Standard.		
Hydro One Networks Inc.	Disagree	We agree in changing the text as proposed only if R1 is expanded as suggested below. The standard as written is primarily, if not exclusively focused on outage prevention through one means, to keep vegetation out of the Critical Clearance Zone. The burden to accomplish this is placed on the Transmission Owner/Operator as it should be. The first section highlights that a program is required, but does not provide a requirement above this simplistic view, and from our perspective the Measures do not introduce any further rigour. This simplistic approach, in our opinion, does not adequately address the reliability risks associated with the various methodologies of managing vegetation. The White Paper notes removal is superior to pruning in ensuring tree conflicts do not occur. The White Paper includes elements of vegetation management risks, but the revised standard for the most part excludes this issue. One could argue that the audits and fines will manage reliability risks, but we are not convinced that this will do so in a consistent and adequate manner. There are numerous clearance risk factors associated with managing vegetation on rights of way. Some of these are: accurate measurement of conductor sag, accurate measurement of vegetation, vegetation growth rate, conductor sway, tree movement. If one looks at Table 1, the Clearance Distances are to the nearest cm or 1/100 of a foot. This makes one wonder, how realistic are the expectations laid out in the standard? To manage the risks around the Critical Clearance Zone the Standard requires each Transmission Owner to work with these precise numbers and build in a margin of safety to manage the situation. Will each Transmission Owner use identical criteria to trigger work? This doubtful, so this leads one to believe that the standard has not been designed to produce consistent results, which in our opinion is the case. So one has varied field conditions that are difficult to nail down, precise clearance requirements to the nearest 1/100? and the likelihood of inconsistent margins of safety. We realize that the audit process will help to assess these situations, but it may not be enough to achieve a somewhat uniform risk profile across the transmission systems. Other standards that we are familiar with include a margin of safety such as added clearance above the absolute minimum recognizing that it may not be practical to work to such precise measures. Examples of standards that use this approach to ensure consistent and reliable results include OHSA and the Canadian Standards Association. We are not advocating that this standard follows an identical approach, but do want to highlight that the standard may fall short in the area of managing vegetation management risks which in turn have a direct impact on reliability. Considering the above, it is suggested that the aspect of managing vegetation reliability risks be added to the White Paper to allow Transmission Owners to develop somewhat consistent criteria. Further on the topic of managing risk. We believe that reliability risks are

Organization	Agree?	Question 3 Comment
		directly related to the amount of incompatible vegetation on a right of way that is approaching the Critical Clearance Zone. Incompatible vegetation would be vegetation that has the potential to grow into the Critical Clearance Zone at full growth. We suggest that risks could be reduced significantly by including direction in the standard concerning the management of incompatible vegetation. This would drive a greater degree of consistency among Transmission Owners and would reduce the amount of vegetation on rights of way that have the potential to cause flashover. In addition, this would reinforce the reliability risks associated with vegetation, not just from a clearance perspective but also from a volume perspective, and would provide a more comprehensive view for the public and interest groups. In order to respond to what we consider a shortcoming of the proposed standard, our suggestion would be to expand R1.1 similar to the following: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. It is recognized that reliability risks increase appreciably with an increase in incompatible vegetation on an active right of way, and the Transmission Owner is required to remove incompatible vegetation at a point no later in time when it poses a threat to the reliability of the transmission line. Exceptions include vegetation used for designated visual screens, trees of a historic significance, vegetation to control erosion, agreements made at the time of environmental approval for construction,???etc.
Response: Thank you for your comments. The SDT revised the standard so that it no longer references the "Critical Clearance Zone." The SDT chose, in the revised standard, to use the term "methods" as a more global, all encompassing term that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. But we are sensitive to the issues you raised and have tried to define through the subsections in R1 that specific elements are necessary.		
CenterPoint Energy	Disagree	The term "Active Transmission Line Right-of-way" is not defined in sufficient detail in the Definition of Terms Used in the Standard section to know how to apply the Requirements. The term causes a circular reference problem with the term "Critical Clearance Zone" that refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. There is an attempt to differentiate between the "Total R.O.W." and the "Active R.O.W." portion by using the phrase "occupied by active transmission facilities", but no specific limits of such occupation are included within the definition. Are "active transmission facilities" only the physical energized conductors as-is, where-is? Does "occupied" include the conductor vertical and horizontal movement envelope and any horizontal and vertical electrical clearance as well? Does the term "Active Transmission Line Right-of-way" refer to the legal limits of the right-of-way? The new R9 includes the phrase "within the extent of its easement and/or legal rights" which seems to support that definition. The phrase "a strip of land" seems to refer to a metes and bounds description, but how is that relevant when no specific land space is defined, such as with a railroad occupation or Corp of Engineer's permit? On page 16 of the Technical Reference, there is a reference to the Bramble and Byrnes wire-border zone technique. The wire zone

Organization	Agree?	Question 3 Comment
		is defined in the Technical Reference as "the section of a utility transmission right-of-way directly under the wires and extending outward about 10 feet on each side". Are the limits of the "Active Transmission Line Right-of-way" intended to be equivalent to the Bramble and Byrnes wire zone, or is the Transmission Owner to use its discretion to define the limits? The examples in the Technical Reference document do not define the limits of the "active transmission facilities" either. The "Active R.O.W." limit in Figure 1 and Figure 3 is arbitrary. Figure 2 is supposed to display an edge zone for vegetation to exist, which implies an "Inactive R.O.W" portion, but no such zone is defined. Figure 1 also has trees shown inside the "Total R.O.W." and within the "Inactive R.O.W." that are tall enough and close enough to be within falling distance of the active transmission line which seems averse to R7 for vegetation falling into a conductor when the Transmission Owner likely has legal rights to remove them if they are within the "Total R.O.W." and are within falling distance. The interpretation of M7 will be difficult in this case without a specific method to define the "Active R.O.W." portion of the Total R.O.W. We recommend deleting the confusing terms "Active Transmission Line Right-of-way and "Critical Clearance Zone" and returning to the prior Clearance 2 Requirement with the newly specified minimum clearances from Table I of Attachment 1 as an alternative approach should the definition of minimum vegetation clearance distances remain integral to the Standard.
Response: Thank you for your comments. The Critical Clearance Zone concept has been removed from the latest draft of the Standard. While the SDT believes that the definition of “active transmission line right-of-way” in the Standard is appropriate, this concept will be further reviewed by the SDT in the context of the technical reference and your comments. And we agree that a further explanation is required to eliminate questions like the ones you raised. The new examples in the technical reference should eliminate that ambiguity.		
JEA	Disagree	The standard should EITHER require an entity to have and follow a program OR hold an entity to performance standards, but not both. Requiring a procedure in conjunction with performance requirements incents the entity to write procedures that meet only the minimum requirements of the standard, as they will be audited and held accountable for what is documented and performance against that. If performance requirements are in place without the concurrent requirement for a procedure, then the entity is incented to develop procedures that meet best practices in order to assure that they will meet or beat the performance standards, because in this scenario, such procedures do not expose the entity to additional compliance risk while enhancing reliability.
Response: Thank you for your comment. The Standard provides the framework for Transmission Owners to develop and implement an effective transmission vegetation management program in support of the main reliability objective: preventing sustained outages of transmission lines that could lead to cascading. During the drafting process, many members of the drafting team asserted that several of the requirements are merely facilitative in nature and would be unnecessary if sustained outages are successfully prevented. Because this standard is relatively new compared to standards that were developed from operating policies that had been followed for decades, there is a sense that the benefits of "defense in depth" (keeping the facilitating requirements) may be warranted until entities have more experience with mandatory vegetation management.		

Organization	Agree?	Question 3 Comment
Salt River Project	Disagree	R1.1 states "Specify the methodologies that the Transmission Owner uses to control vegetation". The word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications". Recommend to keep the original wording.
Response: Thank you for your comments. The SDT chose "methods" in R1 part 1.1 to provide flexibility for Transmission Owners to develop their own vegetation management programs. ANSI A300 has been referenced as a best management practice in a footnote to 1.1. The Technical Reference Document provides examples of the variations in methods that are necessary due to the wide diversity of vegetation across North America.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we agree with the suggested changes for the terms proposed , we believe that the Transmission Vegetation Management Program should be focused on removal of incompatible vegetation from the Active Right of Way.R1.1 could read: Specify the methodologies that the Transmission Owner uses to control vegetation and demonstrate that the removal of non-compatible vegetation is a focus within the plan. Incompatible vegetation should be defined as any vegetation which has the potential to grow tall enough to jeopardize the integrity of an applicable transmission line by growing into the Critical Clearance Zone or falling into the Critical Clearance Zone . This would provide clear guidance to all stakeholders, support long term vegetation management philosophies, and complement methods such as IVM where incompatible vegetation is completely removed, and compatible vegetation is encouraged to proliferate, thereby helping to control incompatible vegetation in an environmentally positive manner.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs.		
Western Area Power Administration, Upper Great Plains Region	Agree	A question that has surfaced during discussions within the industry is "Can the Transmission Owner designate an active R/W width that is less than the easement width even with a single-circuit line with no R/W set aside for vegetation buffer or future development?" OR, does the easement width equate to "Active T-Line ROW" under the situation described above.
Response: Thank you for your comment. The intent of the Standard is that such rights-of-way as identified in your response are considered as "active transmission rights-of-way" in general for their full width. The definition of "active transmission line right-of-way" was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document.		
Western Utility Arborists	Agree	Yes, we agree, subject to the qualification about "active" rights-of-way under Comment #16. Under R1.1, it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work

Organization	Agree?	Question 3 Comment
		specifications.” The Western Utilities recommends keeping the original wording. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. The standard now redirects efforts to avoiding outages instead of managing vegetation.
Response: Thank you for your comments. The SDT has re-written this Requirement to address your concerns in a manner that allows transmission owners flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. Moreover, we believe the Standard as subsequently revised provides flexibility for Transmission Owners to develop their own vegetation management programs. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
Southern California Edison Company	Agree	Q3: No Comments.
Response: Thank you for your response.		
FirstEnergy	Agree	The Inactive Right of Way, by definition, should include a strip of trees on each side of the of the right of way that was purchased, but not cleared at the time of construction. This could be a narrow strip ten feet on each side that is intended for future hazard tree removal.
Response: Thank you for your comment. The definition of “Active Transmission Line Right-of-Way” has been modified in the current draft of the Standard. The SDT believes that the definition of “Active Transmission Line Right-of-Way” as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical “set aside” which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of “active transmission line right-of-way” included in the Standard. The scenario presented in your comment does not provide enough information for the		

Organization	Agree?	Question 3 Comment
SDT to provide a definitive answer. The definition of “Active Transmission Line Right-of-Way” has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. However, the SDT does not agree that a categorical “set aside” which is not active but can be is appropriate for all Transmission Owners. Rather, some Transmission Owners may want to manage the entire rights-of-way. But flexibility is permitted within the current draft.		
ITC HOLDINGS	Agree	The standard doesn't actually explain or define the Active Transmission Line Right of Way.
Response: Thank you for your comment. A definition of “Active Transmission Line ROW” is included in the Standard. This definition has been modified in the most current draft of the Standard. The technical reference will provide further clarity.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 3
Response: Thank you for your comment.		
American Electric Power (AEP)	Agree	While Requirement R1 does not actually define "Active Transmission Line Right of Way" (it is defined on page 2 of the Standard), AEP concurs with R1, except as noted below for R1.4.
Response: Thank you for your comment.		
Platte River Power Authority	Agree	The list of terms, "objectives, practices, approved procedures and work specifications," from version 1 provides more clarity that the one word "methodology" and should both be replaced. The newly defined term "active transmission line ROW" provides clarity to the portion of the ROW requiring vegetation management and is a valuable addition to the standard.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
American Transmission Company	Agree	We agree with the idea but the term "active transmission facilities" needs additional clarity. This clarity could be accomplished with a footnote. Proposed Footnote: A transmission facility that contains a transmission line to which FAC-003 is applicable. The proposed footnote aids in the identification of applicable transmission facilities.
Response: Thank you for your comment. Applicable lines are defined in Section 4 of the Standard.		

Organization	Agree?	Question 3 Comment
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	My disagreement with R1
Response: Thank you for your comment; however the SDT does not understand your comment.		
National Grid	Agree	Defining "Active Transmission Line Right-of-Way" solves the Right-of-Way definition problem within the SAR.
Response: Thank you for your comment.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	Yes, we agree, subject to the qualification about “active” rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviors that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says “Specify the methodologies that the Transmission Owner uses to control vegetation.” The single word “methodologies” does not adequately replace “objectives, practices, approved procedures, and work specifications.” We recommend that the SDT retain the original wording.
Response: Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
San Diego Gas & Electric	Agree	Yes, we agree, subject to the qualification about "active" rights of way under comment 16. Under R1.1 it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications." We recommend keeping the original wording.
Response: Thank you for your comment. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1.		
Northeast Utilities	Agree	With respect to "active transmission line ROW" the examples provided in the Technical Reference document for FAC-003-2 show that any areas of the easement or fee-owned right-of-way not cleared in accordance with

Organization	Agree?	Question 3 Comment
		company approved design standards will not be considered "active transmission line ROW". Any vegetation contacts resulting from trees that fail in these non-cleared sections ("corridor edge zones") would not constitute a violation of FAC-003-2.The definition of the "active transmission line right-of-way" states that this does not include areas of the easement or fee-owned property that is unused or inactive and intended for other facilities. Does this imply that areas not cleared and not intended for other facilities are part of the active right-of-way? If a company had constructed new lines and allowed for a buffer strip of the easement that was not cleared, but is also not intended for new facilities, and trees are allowed to remain in this strip - that an outage from contact with a tree falling into the lines from this buffer would constitute a violation of R7 as a tree falling from within the active right-of-way? Does this imply that trees in these buffer strips must be removed? This will constitute a very costly and problematic position that will result in extreme adverse public opposition to the required clearing. It is suggested that the clearing limits of any right-way comply with some established standards or codes. A utility should not be allowed to eliminate a large number of vegetation violations by simply decreasing the size or width of the active right-of-way. However, this may also need to be flexible when new lines are constructed when easement widths are limited due to local or state requirements.
Response: Thank you for your comments. The definition of "Active Transmission Line Right-of-Way" has been modified in the current draft of the Standard. The SDT believes that the definition of "Active Transmission Line Right-of-Way" as currently defined is appropriate. The definition was developed to recognize that in some cases additional ROW width was secured to allow for buffers and future expansion. This is further described in the technical reference document. The new section in the technical reference attempts to address these issues.		
Buckeye Power, Inc.	Agree	OK with R1. However, the active transmission line right of way seems to be a reduction in ROW width which would likely decrease reliability during the one moment when we need it most.
Response: Thank you for your comment. The "active transmission line right-of-way" definition has been developed to address rights-of-way obtained for future facilities. It is not intended to diminish the Transmission Owners' responsibility to manage vegetation on a right-of-way which was acquired solely for the purpose of the subject line and is necessary for the reliable operation of the line.		
Great River Energy	Agree	GRE agrees but requests further clarification on the definition of the term "Active" in Active Transmission Line R.O.W. For example: A utility has a 150 foot easement for a 230kV line and currently manages 80 feet. First; is it the intent of the standard that the utility manage the entire 150 foot easement? Second; is the entire easement considered the Active Transmission Line R.O.W?
Response: Thank you for your comment. The Transmission Owner is responsible for determining the Active ROW width based upon the definition of "active transmission line right-of-way" included in the Standard. The scenario presented in your comment does not provide enough information for the SDT to provide a definitive answer. The definition of "Active Transmission Line Right-of-Way" has been changed in the most current draft. In addition a technical reference document with a more detailed explanation of this topic will be issued with the next draft. These documents should provide clarity.		

Organization	Agree?	Question 3 Comment
BCTC	Agree	Yes, we agree, subject to the qualification about "active" rights-of-way under Comment #16. We would also like to point out that the original intent of the standard was to ensure that utilities had a complete vegetation management program. The new standard is evolving towards an outage control program, and no longer encourages programs or behaviours that would ensure the causes of outages are prevented long before they become a problem. Instead, it redirects efforts to avoiding outages instead of managing vegetation. If this is now the preferred approach, the term Transmission Vegetation Management Program is no longer valid and should perhaps be changed to the Transmission Vegetation Outage Prevention Program. Under R1.1, it says "Specify the methodologies that the Transmission Owner uses to control vegetation." The single word "methodologies" does not adequately replace "objectives, practices, approved procedures, and work specifications." BCTC recommends keeping the original wording.
Thank you for your comments. The SDT revised R1.1 to allow transmission owners the necessary flexibility in developing their Transmission Vegetation Management Program. ANSI A300 has been referenced as a best management practice by reference as a footnote to R1.1. The SDT believes that the latest draft includes Requirements that dictate appropriate behavior in controlling vegetation but also added a strong statement that outages, that could have been prevented, are inconsistent with interconnection reliability and should be violations.		
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	

Organization	Agree?	Question 3 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	

Organization	Agree?	Question 3 Comment
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

4. **Documentation and implementation of the transmission vegetation management program which were previously combined in Requirement R1 are now separated in order to apply appropriate VRFs and time horizons. The implementation of some elements has been moved into standalone requirements such as inspection cycles (R3) and annual plan implementation (R9). Do you agree with these revisions and separation? If not, please explain.**

Summary Consideration: Most respondents were in favor of separating the documentation from the implementation. A minority of the respondents wanted to keep the two together. The SAR directed the team to bring the standard into conformance with the latest version of the Sanctions Guidelines. Retention of documentation to demonstrate compliance is now addressed, in most cases, solely in the "Data Retention" section of standards and does not need to be covered in requirements. If an entity does not retain data and there is no impact to reliability, then the retention of that data, if needed to demonstrate compliance, is covered under the Data Retention section.

Some respondents advocated modifying the order or sequence of the standard's requirements. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.

Organization	Agree?	Question 4 Comment
BCTC		Although it's important to have these two separate aspects – documentation and implementation – separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Western Utility Arborists		Although it's important to have these two separate aspects "documentation and implementation "separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second		

Organization	Agree?	Question 4 Comment
Comment Form.		
Progress Energy Florida	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Progress Energy Carolinas	Disagree	The sub-requirements should be moved up to requirement level if the team desires to have different VRFs and VSLs.
Response: The SDT thanks you for your comments. The Standards drafting team has dropped the sub requirement designations and the sub parts are simply listed as part of R1.		
Southern California Edison Company	Disagree	Q4: SCE does not agree with separating the documentation and implementation aspects of the Transmission Vegetation Management Program into separate requirements R3 and R9 (respectively). SCE believes that proposed R3 and corresponding M3 should be eliminated and replaced with a modified version of proposed R9. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. The team believes that conducting inspections is independently important and therefore should be addressed in a separate requirement. The SDT debated the issue of whether to include "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights". The final consensus of the SDT was to exclude the requirement because having the legal rights do not imply one is obligated to exercise those rights to their fullest extent. The SDT did not want to give that impression.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Although it's important to have these two separate aspects " documentation and implementation " separating them spatially in the document itself makes the standard longer than necessary and creates redundancy. It seems obvious that if you prepare elements of the Transmission Vegetation Management Program, they also need to be implemented. The document would be easier to follow if the two elements were kept together.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT have considered various sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		

Organization	Agree?	Question 4 Comment
San Diego Gas & Electric	Disagree	The document would be easier to follow if kept together. Separation of the recommendations and implementation will make this a redundant process, because both will say the same thing.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are distinctly different activities and therefore separated them. Having separate requirements allows for assignment of VRF's and VSL's that more closely reflect their respective characteristics. The SDT considered other sequence options and offer a re-sequencing proposal as Question #12 in the second Comment Form.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to Q #3.		
Salt River Project	Disagree	Although we agree that it is important to identify both aspects of the program for "prepare/documentation" and "implementation", we do not agree that this needs to be documented in separate requirements. It makes the standard longer than necessary and creates redundancy. The document would be easier to follow if the two elements were kept together in the same requirement. In addition, it is not defined what is "VRFs". We understand that this was detailed in a previous draft document as "Violation Risk Factor". This needs to be defined and clarified in order to provide comment back.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The team refers you to the *Sanction Guidelines of North American Electric Reliability Corporation* to explain the use of VRF's and VSL's.		
CenterPoint Energy	Disagree	Additional revisions are needed to clarify the requirements. For instance, R1.3 refers to "the objectives" of the Transmission Vegetation Management Program, which are no longer a required element and are not specified in M1.3. Reference to "the objectives" should be deleted. The last sentence of R1.3 should read: "It shall use the methodologies outlined in the transmission vegetation management program."R1.4 requires a process for a response to an "imminent threat of a vegetation related Sustained Outage", but R2 refers to implementing an "imminent threat procedure" to "prevent an encroachment of the Critical Clearance Zone". The requirement and the implementation should both refer to an "imminent threat of a vegetation related Sustained Outage".
Response: The SDT thanks you for your comments. The team is posting a revised standard and R1 identifies the required elements of the Transmission Vegetation Management Program. The sub requirements have been changed to elements that roll up into R1 and an additional element has been added to cover methods used to control vegetation – the word, "objectives" is not used in the revised standard.		
MRO NERC Standards Review	Agree	The MRO believes that clarity was improved by separating documentation and implementation. The MRO

Organization	Agree?	Question 4 Comment
Subcommittee		suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Midwest ISO Stakeholders Standards Collaborators	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 4
Response: The SDT thanks you for your comments.		
Exelon	Agree	Refer to footnotes in R1.1 and 1.2. Are applicable entities to be held accountable to ANSI A300 (footnote 2) and for providing documentation to support analysis that "local factors" were accounted for (footnote 3)? These footnotes should be requirements or they should be removed and included in a Reference Document not subject to compliance audit.
Response: The SDT thanks you for your comments. Please note the phrase in the current version of footnote 2," while not a requirement of this standard." A300 is a recommended best practice and not a requirement. Footnotes may be used to provide explanatory information.		
American Electric Power (AEP)	Agree	AEP agrees with these changes from Version 1.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for weak documentation and higher sanctions and penalties to be assessed for weak inspection programs and weak vegetation management. However, the standard would be easier to follow if the two elements were kept together in the document.
Response: The SDT thanks you for your comments. The SDT determined that the requirements to document and implement are separate and require different levels of VRF's and VSL's. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
City of Tallahassee	Agree	See Question 6 and 17.

Organization	Agree?	Question 4 Comment
Response: The SDT thanks you for your comments. See the responses to Questions 6 and 17.		
Northern Indiana Public Service Company	Agree	I agree with the separation and re-ordering of documentation and implementation requirements into two distinct groups. This is a welcome improvement to the standard.
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
National Grid	Agree	These revisions and separation make it easier to match requirements and measures.
Response: The SDT thanks you for your comments.		
Ameren	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements
Response: The SDT thanks you for your comments.		
Duke Energy Corporation	Agree	This is a good change from a compliance perspective; the documentation requirements can now be assigned lower VRFs than the implementation requirements.
Response: The SDT thanks you for your comments		
Great River Energy	Agree	GRE believes that clarity was improved by separating documentation and implementation. GRE suggests that moving the requirement for implementation so that it immediately follows the requirement for documentation will further enhance clarity
Response: The SDT thanks you for your comments. The SDT has considered various sequence options and offers a re-sequencing proposal as Question #12 in the second Comment Form.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	

Organization	Agree?	Question 4 Comment
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency	Agree	

Organization	Agree?	Question 4 Comment
(NCPA)		
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	

Organization	Agree?	Question 4 Comment
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

5. In R1.2 the Transmission Owner is required to have an inspection frequency of at least once per calendar year. Do you agree with R1.2? If not, please explain.

Summary Consideration: The majority of the respondents were in favor of the one year frequency. Most of the minority commenters wanted to leave the decision with the Transmission Owner. Since vegetation inspections can be included in overhead maintenance inspections, the SDT did not consider the annual inspection requirement to be burdensome. Several commenters asked for a definition of "inspection" and the SDT is proposing the following modification to an existing NERC Glossary definition of "Vegetation Inspection:"

Vegetation Inspection: The systematic examination of vegetation conditions on an Active Transmission Line Right of Way. This inspection may be combined with a general line inspection. The inspection includes the documentation of any vegetation that may pose a threat to reliability prior to the next planned inspection or maintenance work, considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions.

Organization	Agree?	Question 5 Comment
BCTC		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. At BCTC although all lines are currently inspected at least once every year the thoroughness of the inspection will vary with the local conditions. Some areas with limited vegetation management issues only require a patrol from the air and are often inspected as part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Other areas require a detailed ground inspection. BCTC needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection of the entire operating system. . Therefore, BCTC needs the ability within the Transmission Vegetation Management Program to define what an inspection is in the context of our utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Western Utility Arborists		Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. The Western Utilities need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for

Organization	Agree?	Question 5 Comment
		vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections. The SDT revised the NERC glossary term Vegetation Inspection to allow it to be combined with other line inspections.		
Associated Electric Cooperative Inc.	Disagree	While Associated Electric Cooperative Inc agrees with this requirement in general, there may be areas (e.g. highly arid terrain, open water, etc.) where an annual interval is unnecessary and adds little or nothing to reliability.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
NPCC	Disagree	There were differing opinions within the group. Those entities with extensive overhead transmission felt the once a year requirement was overly prescriptive and would not improve reliability, others were in agreement with the "at least once per calendar year" requirement.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
Tennessee Valley Authority	Disagree	TVA suggests that R1.2 be changed by adding "except in cases where lines or significant sections of lines are over terrain which is void of vegetation(such as bodies of deep water)or over terrain void of any vegetation that can grow to a mature height that could threaten the conductors, then longer cycles will be acceptable". This would avoid unnecessary expenses in such cases.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Western Area Power Administration, Rocky Mountain Region	Disagree	Some areas such as highly developed urban areas, deserts, or grassland prairie may not be conducive to tall vegetation growth and require frequent (annual) inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		

Organization	Agree?	Question 5 Comment
Southern California Edison Company	Disagree	Q5: SCE does not agree with imposing a one-size-fits-all inspection frequency of ?at least once per calendar year? upon all U.S. Transmission Owners. The associated technical paper presents no credible evidence or statistical corroboration to support the proposed inspection frequency. Until such time as a thorough industry study or similar evidence is presented that demonstrates the proposed inspection frequency is cost effective and will enhance system reliability, Transmission Owners should be allowed to establish their own inspection frequency rate. Regarding the enforcement of a non-standardized inspection frequency, should a Transmission Owner incur a vegetation-to-line contact that results in a Sustained Outage, upon review of the investigation results, the responsible Reliability Coordinator and/or NERC could then impose a more stringent inspection frequency requirement upon the infracting Transmission Owner. The imposition of more stringent inspection frequencies could be applied on a temporary or permanent basis, depending on the severity of the outage, but lacking a demonstrated need, good performing Transmission Owners should be allowed to establish their own inspection frequencies based upon their individual needs and operating conditions. SCE respectfully suggests R1.2 be revised to read: "Specify a vegetation inspection frequency that takes into account local and environmental factors."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
SERC OC Standards Review Group	Disagree	While the SERC OCSRG agrees with this requirement in general, there may be areas (e.g., desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
City of Tallahassee	Disagree	While TAL's specific conditions and current process would meet this requirement, I can envision where some conditions may not require an annual inspection. These might include desert conditions, crop fields, over water, etc. To dictate a specific one-year requirement could be burdensome to some utilities with no improvement to the reliability of the BES.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Xcel Energy	Disagree	Add a note of exception to the requirement for inspections on those lines that do not have vegetation management issues (e.g. lines that traverse desert areas only).
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	It would seem also that the T.O. should be expected to react to circumstances that create the need for a more frequent inspection cycle such as conditions that cause widespread vegetation mortality such as drought and/or beetle infestations.
Response: The SDT thanks you for your comments. The standard does restrict the number of inspections and does require the Transmission Owner to examine the local and environmental conditions that might require a greater frequency.		
Consumers Energy Company	Disagree	FERC required NERC in Order 693 to develop appropriate inspection cycles based on local factors. Potential annual tree growth varies considerably within the geography of the United States and FAC-003-1 recognized this factor and left it up to the utility to determine the most appropriate inspection cycle for their system. This was in lieu of having proper data readily available to determine inspection cycles for various areas that could be incorporated into the standard. FAC-003-2 greatly decreases the minimum separation distance between conductors and vegetation. Table 1 shows the minimum distance at sea level for a 345 kV line a 3.12 feet. This is considerably less than the potential annual growth rate of many tree species in many areas of the United States. Therefore, the annual inspection cycle would not be acceptable to identify tree growth that can violate the minimum distance before it occurs. Consumers Energy strongly believes that using the Gallet formula to determine the minimum clearance between conductors and vegetation will decrease the reliability of the system compared to the minimum clearance requirements in FAC-003-1.
Response: The SDT thanks you for your comments. The consensus of the SDT is that the frequency of inspection does not drive the minimum clearance the Transmission Owner operates from. The SDT would expect the minimum clearance to be driven by growth rate and maintenance frequency.		
National Grid	Disagree	R1.2, M1.2 and M1.3 in the Standard all refer to calendar year. National Grid objects to inspections being based on a calendar year. Transmission Owners should be able to define their own "year". (See Question No. 18.)
Response: The SDT thanks you for your comments. By using "once per calendar year" the standard does not confine the inspection to a specific date. This improves flexibility in the inspection schedule.		
Hydro One Networks Inc.	Disagree	Clarification is required on the requirements. The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, change in growing conditions and the Transmission Owner's clearance standards (i.e., if the clearance standards are well above the Critical Clearance then the risk to reliability may be very low, so why inspect for vegetation clearances on an annual basis?) This being the case, clarification is needed on inspection requirements relative to the overall approach used to manage vegetation clearances. For example, Hydro One conducts routine line inspections on an annual basis and identifies clearance issues. Would this

Organization	Agree?	Question 5 Comment
		meet the requirements of the standard?
Response: The SDT thanks you for your comments. Yes. The SDT added a definition for Vegetation Inspection to the standard.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. We need some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
CenterPoint Energy	Disagree	The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency and is arbitrary. The requirement itself does not take into account "local and environmental factors". Since the type of inspection is not specified within the Standard, a frequency of at least once per calendar year is currently workable for CenterPoint Energy, but it may not necessarily be appropriate for Transmission Owners with sparsely vegetated service territories. The Technical Reference for R1.2 should state, "the Transmission Owner is given discretion as to the inspection method", and "that while the inspection frequency is specified, it is not the intent of the Standard that all vegetation be maintained on the same frequency". For example, CenterPoint Energy currently utilizes a 5-year ground-based inspection cycle coupled with a 5-year cycle for vegetation maintenance, and performs a supplemental annual aerial inspection.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations and this is explained in the Technical Reference. Vegetation inspections can be included in overhead maintenance inspections. The SDT added a definition for Vegetation Inspection to the standard which would work provided you do your annual flight.		
Alberta Electric System Operator	Disagree	The AESO believes that the inspection schedule should consider local and environmental factors that may impact the anticipated growth rate of vegetation. In many of the areas in Alberta, due to cold climate and arid conditions, we have slow vegetation growth rates. The requirement for minimum annual inspection is not necessary. We recommend the inspection schedule be determined by the Transmission Owner and documented in its vegetation management plan.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at		

Organization	Agree?	Question 5 Comment
least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Pepco Holdings, Inc	Disagree	While an annual inspection is reasonable and appropriate for all but very low precipitation areas, In Order 693, the Commission directs the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors. The SDT does not seem to have taken the local factors into account. FERC also does not want to leave this up to the Transmission Owners. While the standards being developed are moving many things to the RC, PHI sees that as the only way to have someone other than the Transmission Owner determine an inspection cycle that would consider local factors.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Hydro-Quebec Transenergie (HQT)	Disagree	The frequency and need for inspection is based on a number of factors that include: type of vegetation on a right of way, rainfall during any given year, climate (very slow growth in nordic area), when the last removal of vegetation was done, etc. HQT believes R1.2 is overly prescriptive when a “at least once a year” becomes mandatory; these terms should be removed from the Standard.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done at least annually to cover both engineering and vegetation situations. A more frequent cycle may specified by the Transmission Owner to account for local conditions. Slow growth rates, arid conditions etc. which may render an annual frequency unnecessary for Vegetation Inspections can be included in overhead maintenance inspections.		
Bonneville Power Administration	Agree	It would be helpful to clarify what is expected in regards to what constitutes an inspection. This could be done in the technical reference. Some Transmission Operators inspect vegetation as part of line patrol that focuses on more than just the condition of vegetation along the Right of Way. It should be clear that the Transmission Owner, though required to complete a inspection frequency of at least once per calendar year, has the ability to implement the type of inspection it deems necessary. Also the frequency of once per calendar year may create some unintended reporting difficulties if Transmission Owners currently track progress and completion of inspections using a different convention than calendar year, e.g., fiscal year or other period. It may be helpful to change the wording of R1.2 from "at least once per calendar year" to "once in a twelve month period."
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done		

Organization	Agree?	Question 5 Comment
annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests rewording the requirement to remove ". and environmental" . The MRO believes that local factors includes environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
SERC Vegetation Management Subcommittee (VMS)	Agree	While the SERC VMS agrees in general, there may be areas (i.e. desert terrain) where an annual interval would be unnecessary and not cost effective.
Response: The SDT thanks you for your comments. The consensus of the SDT is that annual inspections add to the reliability of the system.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	The inspection frequency is reasonable.
Response: The SDT thanks you for your comments.		
American Transmission Company	Agree	We agree with a minimum inspection frequency, but believe that the additional verbiage "? that takes into account local and environmental factors" should be deleted. The additional verbiage does not provide greater reliability only more documentation. Proposed Language: Specify a vegetation inspection frequency of at least once per calendar year.
Response: The SDT thanks you for your comments. The consensus of the SDT is that local and environmental factors might demand a greater frequency than once per calendar year and vegetation inspections can be included in overhead maintenance.		
Arizona Public Service Company	Agree	Clarification is required on exactly what an inspection is, which should perhaps be outlined in the white paper. There are areas where inspections are not necessary at all, such as lines over a parking lot, or in a remote desert area. APS needs some assurance that this inspection will not constitute a dedicated, comprehensive vegetation management inspection. Inspections are currently often part of a routine line patrol, where the forester or lineman looks for vegetation concerns in addition to undertaking maintenance work. Therefore, the Transmission Owner needs the

Organization	Agree?	Question 5 Comment
		ability within their Transmission Vegetation Management Program to define what an inspection is in the context of their utility operations.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Pacific Gas & Electric Co.	Agree	This requirement is appropriate to ensure adequate inspection frequencies, however, a clear definition of "inspection" should be contained in either the standard or white paper.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
JEA	Agree	Although there are probably few areas where this is appropriate, the entity should be able to reduce the required number of inspections with RC approval if they are able to demonstrate that vegetation conditions surrounding transmission lines does not warrant inspections at that frequency.
Response: The SDT thanks you for your comments. The consensus of the SDT is that inspection of any operating transmission line should be done annually to cover both engineering and vegetation situations. Vegetation inspections can be included in overhead maintenance inspections.		
Salt River Project	Agree	The Transmission owner needs the ability to define what an inspection is in the context of their utility operation. Inspections may not constitute a dedicated, comprehensive vegetation management inspection, but could often be part of a routine line patrol, where linemen or engineers look for vegetation concerns in addition to undertaking maintenance work. Clarification of that would be helpful, suggest that could be documented in the Technical Reference document.
Response: The SDT thanks you for your comments. The SDT added a definition for Vegetation Inspection to the standard.		
Great River Energy	Agree	GRE suggests rewording the requirement to remove ". and environmental" . GRE believes that local factors takes into account environmental.
Response: The SDT thanks you for your comments. The SDT considers local conditions to account for design and operating situation and environmental includes both the normal expected environmental conditions and changes from the norm such as drought major storms, fire etc.		
San Diego Gas & Electric	Agree	The term "inspection" needs to be better defined, as well as the term "calendar year."

Organization	Agree?	Question 5 Comment
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	

Organization	Agree?	Question 5 Comment
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 5 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

6. **In R1.3 the Standard requires that transmission vegetation management program specify an Annual Plan and specifies parameters for the plan. Implementation of the Annual Plan is separated and placed in R9. Do you agree with R1.3 and the separation of the implementation from the specification of the Annual Plan? If not, please explain.**

Summary Consideration: The majority of the respondents are in favor of the changes. There was a minority of the respondents that made a valid point that elements in the annual plan were lost in the posting. The SDT determined that the requirement to document and implement are separate and require different levels of VRF's and VSL's. The SDT chose a compromise wording to accommodate those points.

Organization	Agree?	Question 6 Comment
BCTC		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives…and methodologies…outlined in the…program." To be consistent with R1.3, BCTC recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Western Utility Arborists		The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, the Western Utilities recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the		

Organization	Agree?	Question 6 Comment
Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
NPCC	Disagree	R1.2 and R1.3 should specifically state calendar year, and the Annual Plan and inspection follow the same calendar year timing.
Response: The SDT thanks you for your comments. The SDT points out that these two parts, R1.2 and R1.3, refer to different aspects of the Transmission Vegetation Management Program. Further, to assist in clarity, the SDT has revised part 1.3 and in doing so has removed the phrase "during the year" since it added no value to the requirement. The SDT does not agree with your suggestion to base the annual plan on a calendar year and feels that the Transmission Owner should retain the flexibility to determine the time period for - Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP annual plan.		
City of Tallahassee	Disagree	While I can agree with a separate requirement (R9) to implement the plan developed in R1.3, they need to both have the flexibility desired in R1.3. I do not see that flexibility in R9. See response to question 17.
Response: The SDT thanks you for your comments. R9 is the implementation of 1.3 which is flexible. The flexibility of 1.3 carries through to R9.		
Northern Indiana Public Service Company	Disagree	I disagree with the elimination of the present requirement R2 (last sentence) that requires a Transmission Owner to have proper quality control (QC) systems and procedures in place to document & track planned UVM work so as to verify it was completed properly to work specifications. The need for this requirement was demonstrated as recently as last year when a grow-in outage occurred at BG&E due to a contractor trimming the wrong tree at the wrong location, a situation that could have been prevented with effective QC.
Response: The SDT thanks you for your comments. The consensus of the SDT is that in order to implement the plan the Transmission Owner must complete its work plan to its standards. The level of QC is within the Transmission Owner's purview.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I think that the Transmission Owner should be able to specify the effective period of the plan whether it is one year or ten years. Arizona utilities are starting to think in terms of multi-year corridor management plans. A one year planning period could be specified as the minimum planning period.
Response: The SDT thanks you for your comments. The SDT agrees that long term plans can be of value and can be done within the standard. The standard is trying to insure the immediate reliability work is budgeted and completed.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies" outlined in the "program." To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and

Organization	Agree?	Question 6 Comment
		objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Arizona Public Service Company	Disagree	The document would benefit from keeping the two requirements together, since they relate to the same topic. Under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the "program." To be consistent with R1.3, APS recommends that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus, the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there exists a small dichotomy since "objectives" are no longer stated in R1 while being referenced in part 1.3. Subsequently the SDT has removed this wording from part 1.3. Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Baltimore Gas & Electric Company	Disagree	See response to question no. 17.
Response: The SDT thanks you for your comments. See response to comments on #17.		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comments. See response to comments on #3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements were kept together in the same requirement (similar to comments stated in Comment #4 above). It makes the standard longer than necessary and creates redundancy. Also, under the new wording in R1, the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3 to "support the objectives" and methodologies "outlined in the..program". To be consistent with R1.3, it is recommended that R1.1 be reworded to

Organization	Agree?	Question 6 Comment
		specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. However, the SDT determined that the requirements to document and implement should be separate and require different levels of Violation Risk Factors and Violation Severity Levels. Thus the SDT respectfully does not adopt your suggestion to keep the two requirements together. The SDT also disagrees with returning "objectives" to R1. We do, however, agree that there is a small dichotomy since "objectives" are no longer stated in R1, while being referenced in part 1.3. Subsequently, the SDT has removed this wording from part 1.3 Further, the SDT has revised R1 to require the Transmission Owner to specifically describe how it will conduct work to comply with the Standard in lieu of requiring the Transmission Owner to only identify general objectives.		
Hydro-Quebec Transenergie (HQT)	Disagree	R1.2 and R1.3 specify calendar year. The individual entities should define the 12 month period for their programs.
Response: The SDT thanks you for your comments. The annual work plan may be for a calendar year or for a fiscal year.		
Western Area Power Administration, Upper Great Plains Region	Agree	The description of the annual plan now appears to require a detailed plan for each line. Under FAC-003-1, Western (UGPR) identified higher priority vegetation during aerial inspection and handled those expediciously. We then addressed a percentage of the lower priority trees based upon a number of agency defined factors (vegetation priority, ground conditions, resource availability, etc). The less rigid annual plan allowed us the freedom to cut the lower priority trees that made the best sense to cut. We are concerned that the additional rigidity will create a ever-changing annual plan because we may have to adjust dozens of lines based on inspections. We question whether it is prudent to occupy finite resources in continually modifying the annual plan when the real benefits accrue from actually performing the vegetation management activities.
Response: The SDT thanks you for your comments. The SDT intent is for the Transmission Owner's Transmission Vegetation Management Program to be developed based on the unique requirements of each Transmission Owner's system. For example, where the Transmission Owner has a heavily forested or geographically large territory the annual plan may address many transmission lines on a cyclic basis along with additional items found on the vegetation inspections. On the other hand, where the Transmission Owner has a very sparsely forested territory, or a small number of transmission line miles, the Transmission Vegetation Management Program may necessitate an annual plan that only addresses items found on the vegetation inspections. Therefore, the specificity of the annual plan is subject to the discretion of the Transmission Owner. We agree that only the appropriate amount of resources should be applied to the execution and management of the annual plan, provided the overall Transmission Vegetation Management Program is effective.		
Progress Energy Florida	Agree	Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Progress Energy Carolinas	Agree	Annual Plan should be a defined term in the standard. Without a definition, the term may be interpreted differently by industry and the regulator. The drafting team should raise the prominence of annual plan and define the attributes of an annual plan.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
Southern California Edison Company	Agree	Q6: SCE agrees in part. Proposal R1.3, requiring Transmission Owners to establish an annual maintenance plan is generally acceptable. However, SCE disagrees with including peripheral information in R1.3 and the institution of a separate implementation requirement (R9). Further, we note that some portions of FAC-003-1 (R2) appear to have been transplanted into proposed R1.3 and that the word “shall” has been replaced with the word “should”. SCE believes that inserting the word “shall” into statements that are clearly advisory in nature does not necessarily create enforceable requirements. As proposed, an enforcement auditor might incorrectly determine that the new “requirement” statements in proposed R1.3, describing the need for “flexibility”, “consideration of permitting and scheduling requirements”, and self-determined “methodologies” is a comprehensive list of items for the maintenance plan. Because this list of program elements is not complete, SCE recommends all text following the opening sentence be removed from R1.3 and inserted into the supporting technical paper. SCE respectfully suggests that R1.3 be revised to read: "Specifies a plan that identifies the applicable lines to be maintained and associated work to be performed."
Response: The SDT thanks you for your comments. The consensus of the SDT is the components of an annual work plan must be part of the requirement to ensure that all plans are adequate. Major changes that could affect reliability must be made.		
FirstEnergy	Agree	Although we agree with R1.3, we suggest it be broken up into subrequirements to allow for better clarity to the reader as well as aid in the development of violation severity levels when developed. We suggest the following:R1.3. Require an annual plan that includes the following as a minimum: (Note: Adjustments to the plan within the year are permissible) R1.3.1. It shall identify the applicable lines to be maintained and associated work to be performed during the year. R1.3.2. Is shall be flexible to adjust to changing conditions and to findings from vegetation inspections. R1.3.3. It shall take into consideration permitting and scheduling requirements from landowners or regulatory authorities. R1.3.4. It shall support the objectives of the transmission vegetation management program and use the methodologies outlined in the transmission vegetation management program.

Organization	Agree?	Question 6 Comment
Response: The SDT thanks you for your comments. Requirement R1.3 has been subdivided for clarity in proposed version 2.		
MRO NERC Standards Review Subcommittee	Agree	The MRO suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. The MRO believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words “during the year” from the requirement but retained the words “within the year” in the requirement.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 6 and proposes that the Annual Plan be a defined term.
Response: The SDT thanks you for your comments. The SDT did attempt to address this concern by breaking the annual plan into 4 separate sub-requirements. We feel this may help limit the range of subjective interpretations of this requirement.		
American Electric Power (AEP)	Agree	AEP agrees with these changes.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Under the new working in R1., the Transmission Vegetation Management Program no longer has a requirement to include objectives. However, there is a phrase in R1.3. to "support the objectives.. and methodologies outlined in the Transmission Vegetation Management Program". R1.3. should be consistent with the wording in R1.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern and the word, “objectives” is no longer used in the revised standard.		
American Transmission Company	Agree	ATC agrees with separating the implementation Requirements from the Annual Plan Requirements.
Response: The SDT thanks you for your comments.		
Manitoba Hydro	Agree	Agree with the separation - but suggest that the time horizon of one year be removed as some changes may push the work beyond the current planning year.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of		

Organization	Agree?	Question 6 Comment
the Transmission Owner, may or may not be constrained to a calendar year. If findings during the year from Vegetation Inspections justify changes to the plan, such adjustments are allowed as long as they occur within the planning year, not after the fact.		
San Diego Gas & Electric	Agree	To be consistent with R1.3, we recommend that R1.1 be reworded to specify the methodologies and objectives that the Transmission Owner uses to control vegetation.
Response: The SDT thanks you for your comments. The SDT has made changes to address this concern.		
CenterPoint Energy	Agree	See comments to Q4 above as well.
Response: The SDT thanks you for your comments. See response to comments on Q4.		
Great River Energy	Agree	GRE suggests removing the words "during the year" from sentence 1 and removing the words "within the year" in sentence 3. GRE believes that having it only within the plan year is too restrictive.
Response: The SDT thanks you for your comments. By definition an annual plan covers a one year period. This one year period, at the discretion of the Transmission Owner, may or may not be constrained to a calendar year. However, in an effort to make the requirement more concise, the SDT did remove the words “during the year” from the requirement but retained the words “within the year” in the requirement.		
WECC Reliability Coordination	Agree	
Associated Electric Cooperative Inc.	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review	Agree	

Organization	Agree?	Question 6 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Agree?	Question 6 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
Northeast Utilities	Agree	
Buckeye Power, Inc.	Agree	

7. **In R1.4 the Standard requires the Transmission Owner to have an Imminent Threat Procedure and specifies elements to be in that procedure. Do you agree with R1.4? If not, please explain.**

Summary Consideration: Approximately half of the comments received were critical of the lack of a definition for imminent threat. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.

About the same number of commenters objected to the "prescriptive" list of other actions for the Transmission Operator, and that language has been removed from R1.4.

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 responsible control center.

Deleted: Transmission Operator

Deleted: , and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.

Commenters also expressed a desire to set the procedure for specific internal needs and the SDT modified the language to give that latitude to the Transmission Owner when developing its Imminent Threat procedure.

Some comments referred to parts of the standard not asked about in this question and the SDT directed the commenters to review the changes in R1, R2 and R4.

Organization	Agree?	Question 7 Comment
Associated Electric Cooperative Inc.	Disagree	The language in R1.4, requiring notification of the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity.
Response: Thank you for your comment. The main purpose of requirement R1.4 is to enhance the responsible operator's situational awareness of the power system's status. Therefore, the salient requirement of this procedure is notification of the responsible operator of any potential threat to the power system. This requirement does not mandate any action of the responsible operator and thus, this entity would not need to be listed in the Applicability section. Please also note that the wording in R1.4 has been altered to change the "Transmission Operator" to the "responsible control center", to better identify the appropriate responsible party.		
NPCC	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 7 Comment</th></tr>
<tr><td></td><td></td><td>approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. 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" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions”. This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system, not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process, therefore the flexibility that can be achieved in the context of this standard would be helpful.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term “approach”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.</td></tr>
<tr><td>SERC Vegetation Management Subcommittee (VMS)</td><td>Disagree</td><td>The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC VMS recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC VMS believes that imminent threats should be a defined term. The definition should be as follows: ?Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to</td></tr>
</table>

Organization	Agree?	Question 7 Comment
better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Progress Energy Florida	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power system.		
Progress Energy Carolinas	Disagree	Progress Energy agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats but only when it is appropriate as defined by the Transmission Owner's imminent threat procedure. We disagree with the requirement to immediately communicate with the Transmission Operator whenever the Critical Clearance Zone is approached. Not every scenario is an issue that requires action by the Transmission Operator: It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 30 feet away from the vegetation) -- This typical situation does not merit notification to the Transmission Operator (which is required by FAC-003-2 as currently written).
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center". The SDT feels this better identifies the appropriate party. The SDT maintains that the salient requirement of R1.4 is notifying the responsible operator of any imminent threat to the power		

Organization	Agree?	Question 7 Comment
system.		
SERC OC Standards Review Group	Disagree	The Requirement as written is too prescriptive and is open to interpretation from an audit perspective with use of the term “immediate” communication and a partial list of activities. Due to limitations of communication capabilities in the field, "immediate" may not be practical. While the White Paper provides insight into what is acceptable communications to the Transmission Operator, the standard is less prescriptive in describing what is an acceptable communication path to the Transmission Operator. We recommend better descriptions in VSLs, measures and the Reliability Standard Audit Worksheet as to what is acceptable. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. The SERC OCSRG recommends that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, the SERC OCSRG believes that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at an immediate risk of a Sustained Outage.”
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The SDT also feels that it is important for the aspects of the imminent threat procedure and the triggers be defined by the Transmission Owner. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
Florida Power & Light	Disagree	The definition of Imminent Threat procedure should be included in the Standard. As FERC has stated with regard to the definition of sabotage, the industry should come up with a standard definition and it should not vary from company-to-company. FPL further disagrees with defining Imminent Threat only in a white paper as proposed by some. The Standard should not refer to other reference documents, especially when it is to add clarity and should define the Imminent Threat procedure as well as its requirements within the body of the Standard.
Response: Thank you for your comment. The SDT disagrees with your comments. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the		

Organization	Agree?	Question 7 Comment
Transmission Owner to develop all other imminent threat procedure components.		
Southern Company	Disagree	The standard requirement, as written, requires the "immediate notification" of the operator. This standard requirement could be interpreted to mandate that this notification take place prior to any other action. There could be times that this communication would take up valuable time needed to relieve the immediate threat. The requirement should be modified to list examples of appropriate actions that could be taken. The Transmisison Owner should be allowed the flexibility of developing a communication process that ensures timely notification of a threat and the proper channels of communication that will be utilized in making the notification. The present wording in the standard alone suggests the individual observing the threat in the field is directly responsible for communicating with the Transmission Operator while the whitepaper tends to be more flexible. The Transmission Owner may wish to have the vegetation contractor notify the Transmisison Owner's forester who in turn will notify the Transmission Operator. While the whitepaper does an adequate job describing acceptable responses, the standard does not. It is recommend the standard, VSL, and Reliability Standard Audit Worksheet better explain what is an acceptable response to the Transmission OwnerP. The requirement then goes on to address specific actions the operator "may" take in response to the notification. The imminent threat processes should be limited to the steps taken to notify the Transmission Operator in a timely manner. FAC-003 is not the appropriate place to address Transmission Operator decisions resulting from notification of a threat to the system.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term “immediate”. We agree that the main purpose of this requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Further, please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system and field communication capabilities. The Violation Severity Levels for this requirement are now binary and self explanatory. The SDT is prepared to provide input in the revision of RSAWs, but under current practice, RSAWs are not developed by standard drafting teams.		
E.ON U.S.	Disagree	The Requirement as written is too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities. Many conditions or threats, requiring immediate removal, would not require communication with the Transmission Operator, who is not an applicable entity for this standard. We suggest that R1.4 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. If R1.4 is not deleted, we believe that imminent threats should be a defined term. The definition should be as follows: “Imminent Threat: A vegetation condition which, if not addressed, will place a transmission line at a significant risk of a Sustained Outage.”
Response: Thank you for your comment. We agree that an imminent threat can exist in many different forms. Part of your concern has been addressed by the removal of the term “immediate”. However, the SDT does not agree with removing the imminent threat requirement. The main		

Organization	Agree?	Question 7 Comment
purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. This requirement allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
SERC Compliance Staff	Disagree	SERC staff agrees with the concept of an imminent threat procedure, but disagrees with this requirement in its current form. The use of the word "immediate" is ambiguous. There are many conditions or threats that may require immediate removal, but would not require communication with the Transmission Operator and may require communication with another entity. SERC staff suggests that the proper communication paths be outlined by the Transmission Owner. Imminent threats should be a defined term, however SERC staff has not developed an objective, unambiguous definition.
Response: Thank you for your comment. Part of your concern has been addressed by the removal of the term "immediate". We agree that the main purpose of the imminent threat requirement is the timely communication of a threat to the responsible operator. Therefore, the requirement wording has been altered to change the designation "Transmission Operator" to the "responsible control center". The main purpose of this requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. While we do agree that the Transmission Owner should outline the proper communication paths, we do not agree that an imminent threat should be defined in the Standard. The SDT feels the		

Organization	Agree?	Question 7 Comment
Transmission Owner should have the flexibility to develop an imminent threat procedure that best fits its system.		
ITC HOLDINGS	Disagree	Agree & Disagree with the question: Agree with the need to have an Imminent Threat Procedure and upon discovery of an IT, the Transmission Operations (Transmission Owner) should be notified. We Disagree however, with the requirement as written as its too prescriptive and is open to interpretation, from an audit perspective, with use of the term “immediate” communication and a partial list of activities that the Transmission Owner may consider. Decisions on what specific system operating actions that could be taken are beyond the responsibility of the vegetation management personnel. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached. It is possible that the Critical Clearance Zone is being approached by vegetation at the lowest point of the Critical Clearance Zone where the conductor may be at its highest point in the Critical Clearance Zone , (potentially 20 or 30 feet from vegetation) and wouldn’t necessitate notification to the Transmission Owner. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented since all vegetation within a Right-of-Way will approach the Critical Clearance Zone as it grows? R1.4 should be changed to ?Require a process for response to vegetation related imminent threat to applicable lines and not the Critical Clearance Zone
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the terms “approach” and “immediate”. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. Also, the term “immediate” has been removed. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of the power system’s status. Please also note that the wording has been altered to change the “Transmission Operator” to the “responsible control center” to better identify the appropriate responsible party. The SDT maintains that the salient requirement of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tennessee Valley Authority	Disagree	TVA recommends that R1.4 and R2 both be removed from this Standard. This is a "zero tolerance" Standard with significant penalties for outage violations. These penalty conditions are the necessary and sufficient conditions for the Transmission Owner to immediately react to any discovered threats to prevent potential outages.
Response: Thank you for your comments. While the drafting team does agree that the penalties for the “zero tolerance” aspect of the Standard certainly provide a strong incentive, we still feel that a requirement for an imminent threat procedure should be included in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the Transmission Owner should develop all other components of the imminent threat procedure to best fit its system.		

Organization	Agree?	Question 7 Comment
American Electric Power (AEP)	Disagree	AEP agrees with the need for a Transmission Owner to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the Cricitical Clearance Zone (Critical Clearance Zone) has been approached. It is possible that the Critical Clearance Zone is encroached by vegetation at the lowest point of the Critical Clearance Zone whereas the conductor may be at its highest point in the Critical Clearance Zone (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding Critical Clearance Zone in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Tampa Electric Company	Disagree	TECO aggres with the need for the Imminent Threat Procedure. However, the use of the new Critical Clearance Zone could create a "fill in the blank" standard. We need to lock these clearances down as an industry so as to define what is an imminent threat and what the Critical Clearance Zone is in terms of specific distances.
Response: Thank you for your comments. The SDT agrees with your concern of having a standard with "fill in the blank" requirements. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed but should not be overly prescriptive. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient part of the imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. **Using the Critical Clearance Zone as an undefined "trigger" for implementing the imminent threat process has been removed from the Standard. The Critical Clearance Zone methodology has been deleted from the Standard.**		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be included in the Transmission Vegetation Management Program, the requirement is overly prescriptive and should be revised to allow Transmission Owners flexibility to develop imminent threat procedures which best fit their systems and protocols. We recommend that R1.4 be reworded as follows: "Require a process or procedure for response to vegetation-related imminent threats to applicable lines. The imminent threat procedure shall require action to eliminate vegetation-related imminent threats, and shall be implemented upon discovery of such conditions". In addition, the definition of "Imminent Threat" should be defined. We suggest the following: "A condition which places a

Organization	Agree?	Question 7 Comment
		transmission line at significant risk of an outage in the very near term". An example of a vegetation-related imminent threat would be an uprooted tree leaning precariously toward a conductor which is certain to make contact with the conductor as the tree falls. Many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission systems, not just imminent threats due to vegetation. In many cases it would make sense for Transmission Owners to have one imminent threat process that covers all imminent threat conditions. The flexibility being recommended would facilitate this.
Response: Thank you for your comment. The SDT agrees that the requirement was overly prescriptive. The requirement has been revised to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient part of this procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols; thereby providing for the flexibility that you have suggested. Along with this line of reasoning, we do not agree that an imminent threat should be defined in the Standard. Again, the SDT feels that the Transmission Owner should have the flexibility to define what constitutes an imminent threat to its individual power system. This flexibility also allows the Transmission Owner to have one imminent threat process in place to cover all imminent threats to its transmission systems, not just imminent threats due to vegetation as you have noted.		
American Transmission Company	Disagree	We agree that entities should have a Vegetation Imminent Threat Procedure, but that the term should be defined. Also see related comments to Question #11.
Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Nebraska Public Power District	Disagree	NPPD agrees that a Transmission Owner should have an imminent threat procedure and the Transmission Owner be immediately notified of any threats. NPPD disagrees with prescribing what needs to be done as a result of the threat. This is condition based and staff can make the right decision as to what corrective actions are necessary.
Response: Thank you for your comment. The SDT agrees that prescribing what needs to be done as a result of the threat should not be included as part of the Standard requirement. This language has been removed from the text as you have suggested. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.		

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system.		
Consumers Energy Company	Disagree	Consumers Energy believes that each Transmission Owner/Operator should have a Vegetation Imminent Threat Procedure. We disagree with this requirement because "vegetation imminent threat" is not defined in the standard. As interpreted, the "vegetation imminent threat" is only what is needed to avoid violating the Gallet formula minimum distance which would allow vegetation approaching close to 3 feet of separation on 345 kV conductors. At this distance, removal of the tree cannot occur without removing the line from service per OSHA rules. Therefore, the tree can "cause" an outage but be acceptable under this standard. Consumers Energy believes that vegetation must be maintained so that extraordinary measures needed to remove the vegetation threat do not have to occur in order to complete the work. Thus, the minimum distance to "trigger" an imminent threat must be greater than the OSHA minimum working distance and therefore the Gallet formula does not provide the protection that FERC demands. During high load periods options a system operator may have to mitigate the vegetation threat may not be available; you may not be able to remove the line from service, derate the line, etc., so the operator must "hope" to get through the high load period without the vegetation causing a outage. Allowing vegetation to approach the Gallet formula distance is unacceptable and severely decreases the reliability of the system.
Response: Thank you for your comment. The SDT does not agree that a vegetation imminent threat should be defined in the Standard. The Critical Clearance Zone methodology has been removed from the Standard. We feel that the Transmission Owner should have the flexibility to not only develop the imminent threat procedure but also define the triggers needed for its particular system. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The notification requirement is a mandatory requirement for all Transmission Owners. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. Aside from the negative economic and operational impacts associated with unscheduled facility outages, failures by the Transmission Owner to effectively execute follow up activities and procedures will most likely lead to a violation(s) of other requirements related to Minimum Vegetation Clearance Distance (MVCD) encroachment or sustained outages.		
Ameren	Disagree	Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance defined in the Vegetation Management plan." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be

Organization	Agree?	Question 7 Comment
		prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. While a definition of "Vegetation Imminent Threat - Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2" would be acceptable and far superior to that which is proposed, it will still be difficult for field personnel to identify, at each foot of a transmission circuit, wherein twice the Gallet distance would be found. See comment on #11 below.
Response: Thank you for your comment. We agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. **We further agree that many situations can constitute an imminent threat, distance from the vegetation to the conductor being only one of such situations, so the references to the Critical Clearance Zone methodology as a defined "trigger" for implementing the imminent threat process has been removed from the Standard. For that matter, the Critical Clearance Zone methodology has been deleted from the Standard. While we do not agree that an imminent threat should be defined in the Standard, we do agree that the Transmission Owner should have the flexibility to develop an imminent threat procedure that allows the appropriate decisions to address the vegetation threat. The requirement, as it has been reworded, allows the Transmission Owner to develop an imminent threat procedure that best fits its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.**		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY currently has procedures that mandate response to imminent threats. The Standard should be made more general and not identify the specific actions that shall be taken in the procedure. The second sentence of R1.4 should be deleted and the first sentence should read, 'Require a process or procedure to respond to vegetation-related imminent threats." This adds the necessary flexibility that utilities require and avoids additional redundant processes or procedures from being developed.
Response: Thank you for your comment. The SDT agrees that the requirement should be more general and has revised the requirement to focus on the main purpose of the imminent threat requirement; which is, to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its systems and protocols, thereby providing for the flexibility that you have suggested.		

Organization	Agree?	Question 7 Comment
Duke Energy Corporation	Disagree	Duke believes that Transmission Owners should have a Vegetation Imminent Threat Procedure, and "Vegetation Imminent Threat" should be a defined term, defined as: "Vegetation observed in the field encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I of the draft standard FAC-003-2." In this case, the threat would require an immediate response and would include communication to the Transmission Operator. From there, the actions that the operator decides to take will be dependent on the incident and system conditions. We do not need to be prescriptive with this requirement but rather allow the Transmission Operator and appropriate field personnel the flexibility to make the right decisions to safely, promptly and appropriately remove the vegetation threat. From a Transmission Owner's perspective, many situations can constitute an imminent threat but this approach will clearly define a "Vegetation Imminent Threat" as it relates to the Purpose of this standard. See our related comment on #11 below.
Response: Thank you for your comment. While we do not agree that an imminent threat should be defined in the Standard, we do agree with your assessment that the Standard needs an imminent threat requirement, but as it was written, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, we have made some major changes to this requirement. The Critical Clearance Zone methodology has been deleted from the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its system; thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Entergy Services	Disagree	1. The requirement should state that each Transmission Owner will be responsible for creating and maintaining a Vegetation Imminent Threat Process. This process will clearly define how the Transmission Owner defines a vegetation imminent threat. 2. The requirement needs to state that only vegetation conditions identified, to the Transmission Owner, by regular field inspections, including aerial inspections, and other internal and external verifiable reports of vegetation imminent threats will be managed through this process. 3. If the standard requires a process to mitigate potential immediate threats to the system, the term ?vegetation imminent threat? must be defined. This definition must not delineate the precise steps that are required to be taken to allow experts as many options as necessary to address each vegetation condition specifically. 4. The list of possible mitigating actions should be removed from the standard since it is not an all inclusive list. Listing these actions in the standard may imply that the entity must do one or all of the actions to be in compliance. The entity must have sufficient latitude to evaluate each possible vegetation condition and apply the most appropriate mitigation steps, up to and including the removal of the identified vegetation.

Organization	Agree?	Question 7 Comment
Response: Thank you for your comments. **1. The SDT prefers to allow the verbiage “an imminent threat of a vegetation-related Sustained Outage” to stand without further definition. The SDT agrees that the Standard needs an imminent threat requirement. However, as it was written for the initial posting, the requirement was overly prescriptive. As a result, and because much of the industry agreed with you, the SDT has made some changes to this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to permit communication with the relevant entity for the Transmission Owner. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the “triggers”, follow up activities, and procedures that best fit its system, thereby providing for the flexibility that you have suggested. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.** **2. See response 1 above.** **3. See response 1 above.** **4. See response 1 above.**		
Salt River Project	Disagree	Agree with R1.4, however with the suggested change: Remove the language "?and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions.". Any standard should not contain advisory-type language, it should be declarative in tone. The suggested actions are not the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these “advisory” actions could fall outside the responsibility of some utilities’ Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center’s situational awareness of reliability dangers to the power system. Please note that this requirement’s wording has also been altered to change the designation “Transmission Operator” to the “responsible control center” to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Northeast Utilities	Disagree	Agree with the need to have and implement when necessary an imminent threat procedure. Disagree with the need to implement the imminent threat procedure merely because a Critical Clearance Zone is being approached, as required by R2. Is there a desired distance from the Critical Clearance Zone where this procedure must be implemented, since all vegetation within a right-of-way will "approach" the Critical Clearance Zone as it grows? How will time of year and operating conditions be factored in, which may change the requirements to perform control during periods of low temperature or low load? It would not be necessary to perform all the requirements of an imminent threat procedure when there is adequate clearance to schedule the

Organization	Agree?	Question 7 Comment
		work without jeopardizing the reliability of the system. For example, in mid winter a line is 8 feet from a tree - there is little chance of the line reacing maximum sag at that time of year and the present condition does not constitute an imminent threat at that time. Also, disagree with the requirement for the imminent threat procedure to include actions that could be taken by the Transmission OwnerP (reduction in line rating, switching). The requirement should be limited to notifications to the Transmission OwnerP, since decisions on what specific system operating actions to take are beyond the responsibility of the Transmission Owner. The decision on what actions to take needs to be performed either by the Transmission OwnerP, or by the Transmission OwnerP in conjunction with the Transmission Owner.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology as it refers to the imminent threat process has been removed from the Standard. The SDT also agrees that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. . Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system, and allows the Transmission Owner to make appropriate decisions on follow up actions.		
Hydro-Quebec Transenergie (HQT)	Disagree	While we strongly agree that an imminent threat procedure should be required in the Transmission Vegetation Management Program, we disagree with some specific wording in R1.4. R1.4 requires immediate communication of an imminent threat to the Transmission Operator, which we would normally agree with. R2 however requires that the imminent threat procedure be implemented when the Critical Clearance Zone (Critical Clearance Zone) is approached by vegetation. "Approached" is not defined as a specific distance, so this part of the requirement is left up to the individual's interpretation. In cases where the Critical Clearance Zone is approached by vegetation no threat to the system is possible if the vegetation is removed before it actually grows into the Critical Clearance Zone . In many cases the vegetation can be removed without taking clearance outages because the Critical Clearance Zone is large, and the conductor and vegetation are still relatively far apart. In such cases there is no need to notify the Transmission Operator, although there is a need to remove the vegetation immediately. We recognize that the opposite is also true, and that in some cases it will be necessary to notify the Transmission Operator because a clearance outage or line de-rating may be required to remove the vegetation. We therefore suggest a simple change to the wording of the second sentence of R1.4. Change "?. 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" to ".. specify actions which may include immediate communication of the threat to the Transmission Operator, a temporary reduction in line Rating, switching lines out of service, or other actions". This change will address the issue which is described above and will allow each Transmission Operator to develop an imminent threat procedure that best fits their system. It should also be noted that many Transmission Operators have imminent threat procedures in place to address all imminent threats to their transmission system,

Organization	Agree?	Question 7 Comment
		not just threats due to vegetation. It makes sense for Transmission Owners to have only one imminent threat process; therefore the flexibility that can be achieved in the context of this standard would be helpful.
Response: Thank you for your comments. We agree with your comments concerning the Critical Clearance Zone and the elusiveness of the term "approach". Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. The wording about other follow up actions that could be taken has been removed from the requirement. Please also note that the wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Pepco Holdings, Inc	Disagree	While an imminent threat procedure is prudent and reasonable, it does not need to consider a Critical Clearance Zone as addressed in our comments on other questions. In fact, one can quickly provide examples of imminent threats when the threat is not even on the right of way. The Transmission Owner should simply have an imminent threat procedure to address identified imminent or potential imminent threats.
Response: Thank you for your comment. We agree with your comments concerning the Critical Clearance Zone methodology. Subsequently, the Critical Clearance Zone methodology has been removed from the Standard. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. Please also note that the requirement wording has been altered to change the "Transmission Operator" to the "responsible control center" to better identify the appropriate responsible party. The SDT maintains that the salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, the SDT agrees that it should be left to the Transmission Owner to develop an imminent threat procedure that best fits its system.		
Southern California Edison Company	Agree	Q7: SCE agrees in part with the content of R1.4 because of its similarity to existing requirement R1.5 in FAC-003-1. However, we disagree with the drafter's inclusion of peripheral information following the first sentence. We also note that the second sentence of proposed R1.4 includes both a requirement and a recommendation. SCE believes this and similar recommendations are best suited for the supporting technical paper. SCE respectfully suggests that R1.4 be revised to read: "Specify a process or procedure for communicating an impending vegetation-to-line contact that may result in a sustained outage and the appropriate response measures."
Response: Thank you for your comment. The SDT feels that the main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of the power system's status. We agree with your suggestions to exclude some of the peripheral language included in this requirement. Thus, the SDT has removed references to the Critical Clearance Zone, the word "immediate", and the wording referring to other actions that may be taken by the responsible operator. Please also note that the wording has been altered to change the "Transmission		

Organization	Agree?	Question 7 Comment
Operator" to the "responsible control center" to better identify the appropriate responsible party.		
Western Utility Arborists	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language" it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comments. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Bonneville Power Administration	Agree	BPA agrees with 1.4, with the following change. The ending phrase: "and may include actions such as a temporary reduction in line Rating, switching lines out of service, or other actions" should be eliminated. Not only does BPA feel it is inappropriate to use advisory-type rather than declarative language in a Standard, BPA feels it is also questionable to give examples of imminent response actions that are often not within the direct capability of a vegetation program to enact. Eliminating the reference to these possible actions leaves it up to the Transmission Operator to decide what the eminent threat response is.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the direct capability of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
FirstEnergy	Agree	The safety of the personnel required to remove a tree or vegetation on or near an energized conductor must be considered when implementing the imminent threat procedure. Although this is a reliability standard, the safety of the personnel may be one "trigger" to implement the imminent threat procedure. That being said, the workers on site, in their judgment, are not able to remove the vegetation safely then the imminent threat procedure would be implemented. See comments for Critical Clearance Zone .
Response: Thank you for your comment. The SDT also believes human safety must be major consideration in this requirement. The Transmission		

Organization	Agree?	Question 7 Comment
Owner may include in its Imminent Threat procedure appropriate considerations for personnel safety as a trigger. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. The SDT made major changes to make the requirement less prescriptive. Also, the wording has been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The Critical Clearance Zone methodology has been removed from the Standard.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that it is very important for the applicable entities to posses a Imminent Threat Procedure. The MRO also believes that the term "Imminent Threat" is subjective an should be defined.
Response: Thank you for your comment. We have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. We do not agree that an imminent threat should be defined in the Standard. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its system. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure.		
Western Area Power Administration, Rocky Mountain Region	Agree	The Technical Reference document could be expanded to explain that a well rounded Imminent Threat Procedure should contain many mitigation alternatives to appropriately address a wide range of field situations, including a "no immediate field action is required" option. For example, further investigation of a potential imminent threat situation may reveal that the situation has been erroneously reported or incorrectly measured and therefore no immediate vegetation removal actions are required. A utility's Imminent Threat Procedure may also address situations beyond just vegetation related incidents.
Response: Thank you for your comment. The SDT agrees that many situations can constitute an imminent threat beyond just vegetation related incidents. The requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.		
Platte River Power Authority	Agree	Imminent threat is not a defined term in the NERC Glossary of Terms so it could be construed as a fill-in-the-blank requirement by FERC as each Transmission Owner could define Imminent Threat differently. Imminent threat should be defined or the requirement should be reworded to define what types of situations would require a procedure. Also, the language, "and may include actions such as a temporary reduction in line rating, switching

Organization	Agree?	Question 7 Comment
		lines out of service, or other actions" should be removed from the standard but could be included in the imminent threat procedure or definition.
Response: The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.**		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	The USFS would be expecting the Transmission Owner to be documenting the imminent threat procedures in an operating plan or corridor management plan that would be approved by the designated USFS decision maker. If such procedures are documented in the Transmission Owner's Transmission Vegetation Management Program and are compatible with USFS resource management direction, then the imminent threat procedures could be incorporated in the agency-approved operating plan by reference. If the Transmission Owner disputes any restrictions that are placed by the USFS on the imminent threat procedures, the USFS has an administrative appeals process which the Transmission Owner can use, but those procedures can be time-consuming and probably would not be perceived by the Transmission Owner as being neutral for negotiation purposes. It might help if a third federal party like NERC could help resolve disputes between the Transmission Owner and the USFS on the imminent threat procedures. Although the USFS would object to unreasonable intrusion of NERC into normal USFS land management prerogatives, imminent threat procedures would seem to be a topic for which NERC should take a very strong position, especially with a standard that identifies minimum vegetation clearances as related to prevention of arcing potential, or in other words, vegetation that should be considered hazardous and in immediate need of treatment.
Response: Thank you for your comments. The SDT developed this standard to apply to Transmission Owners in support of bulk electric system reliability. While there may be similar areas of regulation between the purview of NERC and the USFS, this standard is not intended to be incompatible with any USFS resource management direction. That being said, any NERC standard approved by the FERC does not need to be incorporated into "the agency-approved operating plan". In regard to the suggestion that NERC assist in resolving disputes between USFS and Transmission Owners, this would be beyond the scope of NERC. **The SDT suggests that USFS and affected Transmission Owners review language in permits and change that language to allow perpetual ingress and egress and vegetation maintenance without case-by-case application and review. Such a change would prevent current problems where it takes**		

Organization	Agree?	Question 7 Comment
upwards of one year before vegetation maintenance is allowed to proceed. The SDT has made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. For instance, we agree that the wording referring to other follow up actions that may be taken by the operator is too prescriptive and has been removed from this requirement. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that the requirement wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The SDT feels this is a better approach than to have a rigid definition of an imminent threat procedure. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit the wide range of field situations that are possible to encounter.		
Manitoba Hydro	Agree	Suggest removing, "and may include actions such as a temporary reduction in line rating, switching lines out of service, or other actions", as this is outside the scope of a vegetation management program.
Response: Thank you for your comment. The language you mention has been removed from the requirement as you have suggested. The SDT agrees that these actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Pacific Gas & Electric Co.	Agree	PG&E agrees an imminent threat procedure is a critical component of the standard and should be contained in the Transmission Vegetation Management Program. See additional comments for Q11.
Response: Thank you for your comment. See the responses to comments on Q11.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even applicable under the scope of a vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the scope of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system.		

Organization	Agree?	Question 7 Comment
Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
San Diego Gas & Electric	Agree	We recommend that any advisory language be removed, and replaced with a declaration to the utilities.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested, The remaining declaratory language addresses the main purpose of the imminent threat requirement which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any potential threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation		
WECC	Agree	But for clarity, "Imminent Threat Procedure" should be replaced with "Vegetation Imminent Threat Procedure".
Response: Thank you for your comment. The SDT believes that the context is sufficiently clear.		
Arizona Public Service Company	Agree	APS agrees with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Baltimore Gas & Electric Company	Agree	This requirement references Danger trees which according to ANSI A-300, Part 7 is any tree that could fall on the conductor. Should this more appropriately be changed to Hazard tree which is a structurally unsound tree? It might be helpful if an imminent threat were defined, e.g. trees that are presently encroaching in or near the Critical Clearance Zone , or trees that by virtue of their hazardous condition appear to be likely to fall into or near the Critical Clearance Zone in the near future. (or just leave the explanation to the White Paper)

Organization	Agree?	Question 7 Comment
Response: Thank you for your comment. We agree with most of your comments and have made some major changes to this requirement due to the overwhelming response from industry that the imminent threat requirement was needed, as long as it was not an overly prescriptive requirement. Many situations can constitute an imminent threat, "danger" or "hazard" trees being only one of those situations. Further, due to the undefined "triggers" associated with the Critical Clearance Zone methodology, this approach has been removed from the Standard. **The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the "triggers", follow up activities, and procedures that best fit its situation. The SDT feels this is a better approach than to have a rigid definition of an imminent threat.**		
JEA	Agree	It is appropriate to require procedures to respond to "emergency" conditions; however Imminent Vegetation Threat should be a defined term.
Response: Thank you for your comment. The SDT prefers to allow the verbiage "an imminent threat of a vegetation-related Sustained Outage" to stand without further definition.		
BCTC	Agree	We agree with 1.4, with the following qualification: Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program.
Response: Thank you for your comment. The advisory type language has been removed from the requirement as you have suggested. The SDT also agrees that these "advisory" actions could fall outside the responsibility of some utilities' Transmission Vegetation Management Program. The main purpose of the imminent threat requirement is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation.		
Great River Energy	Agree	GRE agrees and believes that it is very important for the applicable entities to posses an Imminent Threat Procedure. GRE recommends that the Imminent Threat procedure be renamed "Vegetation Imminent Threat Procedure" so as to clearly identify the procedure in the event that a company has imminent threat procedures for more than one situation.
Response: Thank you for your comment. We agree that many situations can constitute an imminent threat; however, the SDT did not rename the		

Organization	Agree?	Question 7 Comment
overall procedure as you have suggested. It is acceptable to have the imminent threat procedure for this standard included in a larger corporate procedure or set of procedures that address a wider array of threats. Instead the requirement has been rewritten to focus on the main purpose of the imminent threat requirement; which is to enhance the responsible control center's situational awareness of reliability dangers to the power system. Please note that this requirement's wording has also been altered to change the designation "Transmission Operator" to the "responsible control center" to better identify the appropriate party. The salient requirement of an imminent threat procedure is notification of the responsible operator of any imminent threat to the power system. Beyond this, it is left to the Transmission Owner to determine the follow up activities and procedures that best fit its situation. The SDT feels that this approach allows the Transmission Owner the flexibility to have imminent threat procedures for more than one situation which remain outside the specific requirements of the vegetation Standards.		
Santee Cooper	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Long Island power Authority	Agree	
National Grid	Agree	

Organization	Agree?	Question 7 Comment
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
CenterPoint Energy	Agree	
Buckeye Power, Inc.	Agree	

8. Requirement 1 section R1.5 replaces Version 1 sub-requirement R1.4. This section is now referred to as interim corrective action process. This process addresses situations where vegetation maintenance activities cannot be performed as planned. The term corrective action plan is used in lieu of mitigation plan to avoid confusion with other uses in NERC of "mitigation plan". Do you agree with R1.5? If not, please explain.

Summary Consideration: Many of the stakeholders asked about the use of the word "interim" in R1.5 and what a constraint is. The SDT explains that 1.3 of the version 2 standard is intended to allow Transmission Owners to adjust the annual work plan to reflect such changes as a long term fix. Part 1.5 is intended to address an interim constraint such as customer refusals, governmental agency imposed restrictions, etc. To help clarify, the SDT added the word "temporarily" to the language noted in requirement R1.5. The SDT also added a new requirement R1.6 to address long term strategies.

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

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 8 Comment
Western Area Power Administration, Rocky Mountain Region		The specifics of a "plan" as required by R1.4 in version 1 of the Standards has been replaced with the generalities of a "process" required by R1.5 in version 2 of the Standards. At the time of an audit, the adequacy of a general process is harder to measure than the adequacy of the specific mitigation measures that were previously required by R1.4 in version 1 of the Standards. It is unclear what an auditor will be looking for to determine compliance with R1.5 - will the auditor be looking for generalities or specifics? Further, if a utility has documented their interim corrective action process, but it is not followed, is this a violation of the Standards?
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). The measure for Interim Corrective Action requires it be included in the Transmission Vegetation Management Program and failure to do so would be a violation.		
City of Tallahassee	Disagree	The use of the term "interim corrective action" implies that a permanent solution or return to the original plan must be pursued. I would change this to "alternate maintenance" process to prevent non-compliance if the Transmission Owner is constrained and has reached an agreement with the land owner that works to maintain

Organization	Agree?	Question 8 Comment
		the reliability of the line.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. If a Transmission Owner reaches an agreement for "alternate maintenance" in these situations, Requirement R1,Part 1.3.3 allows for adjustment of the annual work plan. Alternative maintenance actions as suggested are now addressed in new Requirement R1,Part 1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Northern Indiana Public Service Company	Disagree	The existing R1.4 is focused on identifying where vegetation clearance objectives cannot be met at the time UVM work is performed due to restrictions outside of the Transmission Owner's immediate control. The proposed revised standard is focused on situations where work scheduled in the annual plan cannot be performed as planned for any reason. Can a constraint on planned work be internal such as budget related? Why bother with a corrective process for constrained planned work if the work not completed as planned poses no risk of causing an outage? I strongly believe that the sole focus of this provision must specifically address individual locations where, due to restrictions outside of the Transmission Owner owner's control, vegetation clearances specified in the Transmission Vegetation Management Program cannot be obtained. This section of the standard should be about trees being closer to conductors than they should be due to factors beyond the Transmission Owner's control, rather than whether or not planned work was performed.
Response: Thank you for your comments. Interim corrective actions are intended to address situations such as customer refusals, governmental agency imposed constraints, etc. Requirement R1, Part 1.3 requires that the annual work plan shall be documented and Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tampa Electric Company	Disagree	The phrasing above references a "corrective action plan". However, the standard as written is stated as an "interim corrective action process". These are not one and the same. Interim implies a truly temporary condition. As described on page 21 of the Technical reference, however, some of these operational issues may not be "interim".
Response: Thanks for your comments. The SDT agree that "interim" should have been included in the question. The Technical Reference document does not appear to be in conflict with this. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part 1.6 a to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Manitoba Hydro	Disagree	Agree with the change in terminology - but would suggest that wording clarify that this is not only for situations where the utility is unexpectedly prevented from implementing its annual plan - but also for areas where it is

Organization	Agree?	Question 8 Comment
		unable to implement its clearance requirements due to property rights limitations.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
National Grid	Disagree	National Grid agrees replacing mitigation plan with corrective action process. However, National Grid questions the use of "interim" for a corrective action process in R1.5, and suggests striking "interim".
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5.		
CenterPoint Energy	Disagree	Since there is no longer a reference to defined clearances in the Standard, it is unclear under what specific "constrained" conditions R1.5 applies. R1.5 does not have a sister requirement for implementation within the Standard which implies it has a diminished value. R1.5 and M1.5 should be deleted as a requirement and measure, but should be footnoted as best practice as was ANSI A300 in R1.1.
Response: Thank you for your comments. The SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). A new Requirement R1, Part1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
American Transmission Company	Agree	ATC agrees with the concept but disagrees with the proposed language. ATC believes the term "interim" should be removed from R 1.5. In some cases, a corrective action can end up being a long term/normal fix. Proposed Language: Specify a corrective action process that will be used when established clearances or methodologies are altered.
Response: Requirement R1, Part 1.3 requires that the annual work plan shall be documented. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. A long term fix would be an adjustment to the annual work plan. In Requirement R1, Part 1.5, the SDT intended to require a documented process for Transmission Owners to develop plans which address instances such as customer refusals, government agency imposed constraints, etc. It is not intended solely for situations where initial desired clearances could not be achieved (as in requirement R1.4 of version 1 of FAC-003). To add clarity the SDT added the word "temporarily" to Requirement R1, Part 1.5. Long term strategies are addressed in new requirement R1.6 as noted above in the consideration of comments to address long term maintenance strategies to ensure Table 1 clearance distances are never		

Organization	Agree?	Question 8 Comment
violated.		
Southern California Edison Company	Agree	Q8: SCE agrees in part with the revisions to R1.5, including the proposed phrase "corrective action process". However, we do not believe it is necessary to include the term "Transmission Owner" in the sentence because the entire standard is clearly applicable to Transmission Owners. SCE respectfully suggests that proposed R1.5 be revised to read: "Specify an interim corrective action process for use when planned vegetation maintenance is deferred."
Response: Thank you for your comment. The SDT considered your suggested language and feels the language used in the draft standard is appropriate in order to maintain consistency with other parts of the standard.		
Western Utility Arborists	Agree	Yes, we agree.
Response: Thank you for your participation.		
FirstEnergy	Agree	We agree with the concept of a corrective action plan. However, it is not clear what flexibility the Transmission Owner is afforded in making adjustments to the work plan that may carry over from one calendar year to the next. Legal issues with property owners or other factors may prevent the utility from carrying out the work plan as scheduled. Also, we question the use of the term "constrained". It should be clear as to what constitutes appropriate or valid constraints.
Response: Thank you for your comments. Requirement R1, Part 1.3.3 permits adjustments to the annual work plan. As to your next concern, Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. Refer to the Technical Reference document for additional information.		
MRO NERC Standards Review Subcommittee	Agree	The MRO believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. The SDT uses "interim" to convey the temporary nature of these situations. To add clarity the SDT added the word "temporarily" to Requirement R1. Part 1.5 and a new Requirement R1, Part 1.6 was added to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 8
Response: Thank you for your participation.		

Organization	Agree?	Question 8 Comment
Platte River Power Authority	Agree	The term corrective action plan adds clarity.
Response: Thank you for your participation.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	In my opinion, problems between the Transmission Owner and the USFS over the Transmission Vegetation Management Program should be worked out before a Transmission Vegetation Management Program is ever finalized. A dispute resolution process outside the control of either party would be very helpful and would probably facilitate quicker solutions than if the Transmission Owner and the USFS are left to work out problems on their own. If a Transmission Vegetation Management Program is prepared in a vacuum, the problems may not come to light until some kind of outage actually occurs. It would be much better to flush any disagreements and deal with them before any outages actually occur.
Response: Thank you for your comment. We agree with the sentiment of collaboration and cooperation expressed. We are somewhat constrained by the types of entities that must be subject to this standard. The USFS, as a government agency, is not under the purview of the FERC and is not compelled to comply with this standard however well intended. The SDT would support a dispute resolution process that resolves potential disagreements consistent with the purpose of this standard.		
BCTC	Agree	Yes, we agree.
Response: Thank you for your participation.		
Great River Energy	Agree	GRE believes that the term "interim" should be removed from R1.5. The term Interim is subjective.
Response: Thank you for your comment. Requirement R1, Part 1.5 requires the Transmission Owner to specify a process in its Transmission Vegetation Management Program that the Transmission Owner may use when vegetation maintenance work is temporarily constrained. Constraints may include temporary situations such as caused by customer refusals, governmental agency imposed restrictions, etc. To add clarity the SDT added the word temporarily to Requirement R1, Part 1.5 and long term strategies are addressed in new Requirement R1, Part1.6 to address long term maintenance strategies to ensure Table 1 clearance distances are never violated.		
Progress Energy Carolinas	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	

Organization	Agree?	Question 8 Comment
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 8 Comment
Exelon	Agree	
Central Maine Power Company	Agree	
American Electric Power (AEP)	Agree	
Northern California Power Agency (NCPA)	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	

Organization	Agree?	Question 8 Comment
WECC	Agree	
Arizona Public Service Company	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	

9. Clearance 1 in Version 1 was a "fill-in-the-blank" requirement and was removed from the standard. Do you agree? If not, please explain.

Summary Consideration: Most of the industry comments are in favor of removing the "fill-in-the-blank" requirement. Some disagreed, citing the benefit of having perceived leverage that a Clearance 1 afforded them. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with public and private parties. In addition, the SDT added Requirement R1.6:

1.6 Specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that Table 1 clearances in Attachment 1 are never violated. The maintenance strategies shall consider the sag and sway of the conductor throughout its operating range under rated conditions.

The SDT believes that Clearance 1 may be unnecessarily restrictive in stipulating conductor-to-vegetation distances (as some commenters have done to comply) and therefore removed Clearance 1 in favor of Requirement R1, Part 1.6. which specifically allows for vegetation-to-ground distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions.

Organization	Agree?	Question 9 Comment
Florida Power & Light		FPL neither agrees or disagrees with this removal but provides the following comment. FPL's experience regarding Clearance 1 is that it was an effective way of demonstrating a measurable requirement for compliance when dealing with public entities. The use of a corrective action process to mitigate instances where this clearance was not met before violations occurred is also very effective in promoting reliability and safety in the Standard.
Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 in dealing with public entities and has attempted to retain that capability in Requirement R1, Part 1.6. Furthermore the use of a corrective action process is retained in this latest version but is renamed as an "interim correction action" in lieu of "Mitigation Plan" to avoid confusion with a Compliance Program term.		
Western Utility Arborists	Disagree	The Western Utilities do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Bonneville Power Administration	Disagree	BPA opposes removal of Clearance 1. Clearance 1 provides a regulatory justification for a Transmission Owner to apply and extend proactive vegetation threat prevention programs on its rights of way easements across municipal, state, tribal, other federal and private properties. In many cases, without the regulatory leverage of a Clearance 1 requirement, Transmission Owners would be limited to maintaining less effective and higher risk vegetation management practices where it has legal restrictions, then it presently can implement under the present version of FAC 003-01. BPA recommends that Clearance 1 be placed back into the document, but as a Measure and not a Requirement.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Exelon	Disagree	We do not understand the reference to "fill in the blank" requirement for clearance 1. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO. Clearance 1 in FAC-003-1 is a Transmission Owner requirement. The reference to a clearing zone should be retained, as each Transmission Owner will need to define this in their program so as to avoid encroachments into the Critical Clearance Zone .
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with removal of clearance 1. The clearance 1 was included so that professional arborists could establish the clearance necessary for a transmission owner to reduce the risk of a tree caused power outage. The transmission owner should use ANSI- Standard A300, including PART 7, and other publications to develop best management practices which include clearances at time of maintenance. Clearance 1 provides leverage for Transmission Owners to achieve the clearances stated in their Transmission

Organization	Agree?	Question 9 Comment
		Vegetation Management Program.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	If it is possible for NERC to identify minimum clearance standards as related to arcing potential for hazardous vegetation, it would definitely help USFS field administrators to have some kind of hard and fast standards. If that kind of approach is not reasonable in light of the need to adjust standards for various load conditions and vegetation growth rates, then a prescribed formula for calculating minimum clearances would be the next best thing.
Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing).		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid disagrees with the elimination of Clearance 1. The Clearance 1 requirement in FAC-003-1 was meant to allow a Transmission Owner to establish clearances to be achieved at the time of vegetation management work, and be sensitive to local and regional conditions. National Grid believes that Clearance 1 is needed for public education and safety reasons. Clearance 1 standards allow utilities to specify a cyclic programmatic approach, and gives the utility leverage with local and state regulators and the public to achieve significantly larger than minimal clearances.
Response: Thank you for your comment. The choice of a Clearance 1 distance is left to each Transmission Owner and as such is characterized as a fill-in-the blank style requirement. The SDT team believes each Transmission Owner is free to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may continue to be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances which can be larger than minimal clearances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
Platte River Power Authority	Disagree	Clearance 1 could be defined in the standard in tables developed using IEEE Standards for various voltages, line spans and altitudes. Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT proposes the table of Minimum Vegetation Clearance Distances in this revised version of the standard in Requirement R4, which prohibits vegetation encroachment inside minimum vegetation clearance distances that are developed with Gallet equations for flashover (arcing). The SDT points out that the ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public such as municipalities and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Northern Indiana Public Service Company	Disagree	I am strongly opposed to the removal of Clearance 1 from the standard. Being able to point to this provision has been invaluable to internal communications with upper management and external discussions with land owners and the public concerning UVM. In fact, other than the patrol/inspection requirements, no other provision in the standard has been as essential to preventing grow-in tree contacts than Clearance 1. It has forced Transmission Owner's across the country to re-claim overgrown ROW and re-commit to consistent UVM practices. We all know how easy it is for Transmission Owner's to get weak in the knees in the face of public opposition to proper and prudent UVM work even when it is clear what needs to be done. This dynamic is what led us to the 2003 blackout to begin with. I would like to see the drafting team consider expanding upon the existing model and create three clearances: 1. A clearance at the time work is performed, 2. An action threshold clearance which would trigger the Transmission Owner would take immediate action to clear encroaching vegetation posing an unacceptable outage risk, and 3. A no closer than clearance in which vegetation would never be allowed to encroach in order to prevent flashover.
Response: Thank you for your comment. The SDT team acknowledges the comment with regard to the usefulness of Clearance 1 to internal communications and in dealing with public entities and has attempted to retain that capability Requirement R1. Part 1.6. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
In regard to working distances or as you put it , each Transmission Owner continues to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. **With respect to your 3rd comment, the proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "Best Practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
San Diego Gas & Electric	Disagree	We do not agree with the removal of Clearance 1. We recommend that it be added back into the document, but reworded and moved so it be included as a measurement, rather than a requirement. Without Clearance 1, utilities could be mandated in specific situations to clear so that vegetation is just beyond the Critical Clearance Zone at all times, which is not feasible or cost effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "Best Practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Paart 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
Hydro One Networks Inc.	Disagree	We would agree only if the standard is revised to include the removal of incompatible vegetation as outlined in our response to question 3 above. If not, then added direction or requirements are needed to introduce the elements that combine (to a greater degree than exists under the revised standard) reliability and vegetation management. Clearance 1 accomplished this to some degree.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment. The SDT considered the insertion of the phrase "incompatible vegetation" however decided against it because incompatibility may be arguable and add to disagreement among interested parties. The SDT agrees with the commenter that all vegetation that is identified by the annual work plans and maintenance strategies should be targeted for removal. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The proposed version of the standard has Requirement R4, which prohibits vegetation encroachment inside Minimum Vegetation Clearance Distances that are developed with Gallet equations for flashover.		
Arizona Public Service Company	Disagree	APS disagrees with removal of clearance one. Clearance one should be achieved at time of maintenance which is part of the vegetation program. This gives leverage with dealing with state and federal agencies, tribal and private landowners. This isn't a fill in the blank requirement, however it should be based on sound science in regards to vegetation management. A professional arborist/forester can determine the appropriate amount of vegetation that needs to be obtained at the time of maintenance. APS suggest the following language change for clearance 1. The Transmission Owner shall maintain ROW on Federal, State, Tribal and Private lands in accordance with ANSI-Standard A300 (Part 1)-2001 and (Part 7)-2006 in consultation with companion publication Best Management Practices: Integrated Vegetation Management, 2007. If all utilities followed this standard this would increase the reliability of the bulk electric system and reduce the risk of vegetation outages.
Response: Thank you for your comment. The SDT agrees that any requirement must be based on sound science and believes the Transmission Owner will continue to able to set any working distances it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives when complying with Requirement R1, Part 1.6. The stipulation that the Standard applies to Federal, State, Tribal and Private Lands is contained in the Applicability section. The SDT points out that ANSI A300 remains a "best practice" referenced in this standard and as such may be useful in dealing with state and federal agencies, tribal and private landowners, etc.		
BCTC	Disagree	BCTC do not agree with the removal of Clearance 1. We recommend adding it back to the document, but reworded and moved to include it as a measurement (M), rather than a requirement (R) under the new standard. Many utilities feel that Clearance 1 provides justification and leverage for operational clearances when dealing with organizations such as municipalities. Without Clearance 1, utilities could be mandated in specific situations to clear so that the vegetation is just beyond the Critical Clearance Zone at all times. This could result in pruning at six month intervals, which is not feasible or cost-effective.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		

Organization	Agree?	Question 9 Comment
Salt River Project	Disagree	Recommend adding it back to the document, however, only if it is changed to become a measurement (M) rather than a requirement (R). Leaving it in as a measurement provides justification and leverage for operational clearances when dealing with landowners. Without Clearance 1 landowners may only allow vegetation clearance just at the Critical Clearance Zone at all times, which is not a feasible, cost-effective, or responsible way for utilities to manage vegetation clearance.
Response: Thank you for your comment. The SDT notes that information contained in a Measure would not be mandatory nor enforceable and therefore has minimal usefulness as leverage. The SDT points out that ANSI A300 remains a "best practice" referenced in the proposed standard and may be useful in dealing with the public and private parties. The addition of Requirement R1, Part 1.6 allows for vegetation-to-ground working distances to be used while at the same time accounting for the sag and sway of the conductor throughout its operating range under rated conditions. The SDT believes this is superior to Clearance 1 as this gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
American Electric Power (AEP)	Agree	AEP agrees with the removal of Clearance 1 from the Standard.
Response: Thank you for your comment.		
NPCC	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Western Area Power Administration, Upper Great Plains Region	Agree	While Western (UGPR) agrees with the removal of Clearance 1, we believe it is advantageous for Transmission Owners to have a "trigger distance" in order to have some additional time to plan and schedule vegetation work. The trigger distance is advantageous only if the Regulators do NOT interpret it to be an extended Critical Clearance Zone and do NOT enforce based on "trigger distance" instead of the Critical Clearance Zone .
Response: Thank you for your comment. The SDT team believes the addition of Requirement R1, Part 1.6 continues to allow each Transmission Owner to set any working distances it deems appropriate in order to accomplish the objectives with this Standard. This Requirement 1 Part 1.6 is superior to Clearance 1 as it gives Transmission Owners more flexibility in how they can achieve the reliability objective of Requirement R1.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and fully supports the removal of Clearance 1. The MRO believes that the Gallet equation is a more effective way of determining the required clearances.

Organization	Agree?	Question 9 Comment
Response: Thank you for your comment.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 9
Response: Thank you for your comment.		
Orange and Rockland Utilities Inc.	Agree	We generally agree, however please see comments included in question 18.
Response: Thank you for your comment.		
Baltimore Gas & Electric Company	Agree	While I may agree with the removal of this requirement strictly for reasons of simplification and self-determination, the current requirement forced utilities to structure their Transmission Vegetation Management Program to develop safeguards to keep trees from encroaching into the Clearance 2 envelope. The proposed change will leave the clearance issue beyond the Critical Clearance Zone unaddressed. Responsible utilities will take the appropriate measures and other utilities will not.
Response: Thank you for your comment. Each Transmission Owner is free to use any effective approach it deems appropriate in order to accomplish its Transmission Vegetation Management Program objectives. The SDT believes there are significant disincentives against the behavior you warn about in the revised version.		
CenterPoint Energy	Agree	Designation of Clearance 1 is not required to meet the purpose of the Standard.
Response: Thank you for your comment.		
Hydro-Quebec Transenergie (HQT)	Agree	We agree but believe that the Transmission Vegetation Management Program should target removal of all incompatible vegetation on the Active Right of Way as described in the response to question 3.
Response: Thank you for your comment. The SDT agrees with the commenter that any vegetation that are located within the Active Transmission Line ROW should be targeted for removal using means and strategies described in its Transmission Vegetation Management Program.		
Great River Energy	Agree	GRE agrees and fully supports the removal of Clearance 1. GRE believes that the Gallet equation is a more effective way of determining the required clearances.
Response: Thank you for your comment.		

Organization	Agree?	Question 9 Comment
Southern California Edison Company	Agree	Q9: No comments.
Associated Electric Cooperative Inc.	Agree	
WECC Reliability Coordination	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
SERC OC Standards Review Group	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
FirstEnergy	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	

Organization	Agree?	Question 9 Comment
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	

Organization	Agree?	Question 9 Comment
Pepco Holdings, Inc	Agree	
JEA	Agree	
Northeast Utilities	Agree	
Independent Electricity System Operator	Agree	
Duke Energy Corporation	Agree	
Buckeye Power, Inc.	Agree	

10. Personnel Qualifications in R1.3 in Version 1 was a "fill-in-the-blank" requirement and was removed from Version 2 of the standard. Do you agree? If not please explain.

Summary Consideration: Most commenters agree with the deletion of R1.3 from the approved standard. The" fill in the blank" requirement that was included in version 1 allowed the Transmission Owner to set its own standard for personnel qualifications rather than require the same set of qualifications for personnel in all entities. The SDT recommended removing the requirement as it is not enforceable and recommended against replacing the "fill-in-the-blank" element with a continent-wide set of personnel qualifications. The SDT believes that any set of personnel qualifications enforced on a continent-wide basis would result in a set of "lowest common denominator" qualifications that would be too stringent for some entities, and too lax for others – with no apparent reliability benefit. Instead, the SDT recommended letting entities set their own internal personnel qualifications to best meet their own needs.

Organization	Agree?	Question 10 Comment
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own TVMPs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the TVMP to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
USDA Forest Service, Southwestern Region, Regional	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was

Organization	Agree?	Question 10 Comment
Office for AZ and NM		actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the TVMP and not the adequacy of the field supervision. This does not relieve the TO from providing adequate field supervision.		
National Grid	Disagree	National Grid takes exception to the term “fill-in-the-blank”. National Grid would like Personnel Qualifications to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
San Diego Gas & Electric	Disagree	We feel there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Arizona Public Service Company	Disagree	APS disagrees with the removal of personnel qualifications. The person responsible for vegetation management program should have experience and training in vegetation management and system operations. The International Society of Arboriculture has an ISA Certified Arborist and Utility Specialist certification. This requires the credential holder to have minimal qualifications before sitting for the certification and on going training to maintain the credential. The industry has already responded by providing the information as part of the current standard FAC-003-1. It makes no sense to remove personnel qualifications from the revision.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard,		

Organization	Agree?	Question 10 Comment
remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Central Maine Power Company	Disagree	Central Maine Power Company disagrees with the removal of the qualification statement. The individual responsible for this critical program must be qualified through experience, training, and education. The International Society of Arboriculture has a certification program that can help with guidelines for qualified arborists.
Response: The SDT thanks you for your response. While we agree that the International Society of Arboriculture certifications are credible qualifications for a large work force, these same programs may be too stringent and unnecessary for utilities only needing a very small work force. **It is unknown if certification by ISA or similar organizations has impacted reliability for any Transmission Owner.**		
Northern Indiana Public Service Company	Disagree	If the standard continues to allow T.O.'s to design and implement their own Transmission Vegetation Management Programs and expect them to use BMPs, ANSI A300, develop methods and practices, adapt schedules and plans to changing conditions, etc., then it is reasonable to expect that T.O. personnel responsible for the Transmission Vegetation Management Program to be experts in the field of utility vegetation management with appropriate training, certifications, licenses and credentials. I do not agree with eliminating this requirement. Quite the opposite, I believe that the requirement needs to be more specific as to minimum qualifications key personnel must meet. There are more requirements & qualifications to drive a semi-truck than to design and implement a program (UVM) critical to the operation of the nation's electric grid. Does that make sense?
Response: The SDT thanks you for your response. The SDT concurs that some Transmission Vegetation Management Programs are highly complex and would require highly trained arborists and vegetation management personnel to develop such programs. However, there are many programs that are substantially less complex and do not require that level of expertise. We feel that utilities with complex programs would by nature acquire appropriately trained personnel to implement their programs.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	Perhaps standard M8 could be expanded or clarified to require the Transmission Owner to describe how employees, especially field supervisors, are trained to implement the plan and to prove that the training was actually provided. Some problems have arisen in the USFS Southwestern Region because some Transmission Owners are not providing adequate supervision of field work.
Response: The SDT thanks you for your comment. The requirement that was dropped between the version 1 and version 2 spoke to the qualifications of development and implementation of the Transmission Vegetation Management Program and not the adequacy of the field supervision.		
National Grid	Disagree	National Grid takes exception to the term "fill-in-the-blank". National Grid would like Personnel Qualifications

Organization	Agree?	Question 10 Comment
		to remain in Standard FAC-003-2.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
British Columbia Transmission Corp.	Disagree	BCTC does not agree with the elimination of this requirement. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must have internal standards related to personnel qualifications. We understand that several utilities would like this requirement removed because it created problems in the auditing process. It is unfortunate that this important requirement for an effective vegetation management program has been removed due misapplication of the intent during audits.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the Transmission Owner to set its own standard and does not substantively add to the effectiveness of the Standard.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 10
Response: The SDT thanks you for your response.		
Exelon	Agree	Agree but same comment as above, we do not understand the reference to "fill in the blank" requirement for R1.3. As commonly understood, a "fill in the blank" standard /requirement is one that was assigned to the RRO.
Response: The SDT thanks you for your response. A" fill in the blank" requirement as stated in version 1 allowed the TO to set its own standard as opposed to RRO. In either case the concept of a "fill in the blank requirement" does not substantively add to the effectiveness of the Standard.		
Tampa Electric Company	Agree	While we agree with the removal of "fill-in the blank" requirements, we recommend the inclusion of professional qualifications for staff involved in this Standard. Reading the 42 page technical reference and the attached comment form, all involved need to really understand the Standard as well as industry practices.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Baltimore Gas & Electric Company	Agree	Similar to the response to no. 9, the end result is what counts and each utility will be responsible and accountable for their actions. Qualifications unlike clearance requirements, are far-removed from results and can easily be left unaddressed in the new std.

Organization	Agree?	Question 10 Comment
Response: The SDT thanks you for your response.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We are in agreement with the elimination of this requirement, but not without some qualifications. We feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications. It is unfortunate that this important requirement for an effective vegetation management program has been removed due to concerns with the auditing program.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
CenterPoint Energy	Agree	Designation of Personnel Qualifications are not required to meet the purpose of the Standard.
Response: The SDT thanks you for your response.		
American Electric Power (AEP)	Agree	AEP agrees that the Standard should not stipulate or require personnel qualifications.
Response: The SDT thanks you for your response.		
Platte River Power Authority	Agree	The requirement should be removed because it is a “fill-in-the-blank” requirement. Defining the proper amount of personnel qualifications and training would be too prescriptive for utilities with small vegetation management programs and not prescriptive enough for utilities with large vegetation management programs.
Response: The SDT thanks you for your comments.		
Western Utility Arborists	Agree	The Western Utilities are in agreement with the elimination of this requirement. However, we feel strongly there must be appropriate knowledge to do the work, and that Transmission Owners must at least have internal standards related to personnel qualifications.
Response: The SDT thanks you for your response. Internal standards related to personnel qualifications, while not a requirement of the Standard, remain the internal responsibility of the Transmission Owner in the overall context of complying with the requirements of FAC-003-2.		
Southern California Edison Company	Agree	Q10: No comments.
SERC OC Standards Review	Agree	

Organization	Agree?	Question 10 Comment
Group		
Florida Power & Light	Agree	
Santee Cooper	Agree	
Progress Energy Carolinas	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
Duke Energy Corporation	Agree	
Associated Electric Cooperative	Agree	

Organization	Agree?	Question 10 Comment
Inc.		
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission Company	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	

Organization	Agree?	Question 10 Comment
Independent Electricity System Operator	Agree	
Salt River Project	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

11. The IEEE 516 standard distances were replaced with the Gallet equation distances. Clearance 2 was replaced by the Critical Clearance Zone. The Critical Clearance Zone is defined as the zone of all possible positions of the conductor at the line's designed operating ratings including wind factors. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) The imminent threat procedure, R2, requires action to be taken to prevent an outage when the Critical Clearance Zone is approached. Do you agree with R2? If not please explain.

Summary Consideration: The majority of responders (61%) disagreed with the concept of the imminent threat procedure being associated with the Critical Clearance Zone (CCZ). The key concerns that commenters raised were associated with the Critical Clearance Zone and included the following:

- It is a good concept but is theoretical and difficult to administer in the field
- Respondents preferred a more defined distance that is real-time and measurable
- The word "approach" caused concern due to being vague and open to interpretation

Although there was no clear minority view, a number of respondents recommended eliminating R2 or R4 because of practical difficulties associated with the CCZ and their belief that R5, R6, and R7 were sufficient to achieve reliability

In response, the SDT modified R2 so that it does not use the CCZ to trigger the imminent threat procedure implementation. R2 now requires the Transmission Owner to implement its imminent threat procedure when it has knowledge of such a threat obtained through normal operating procedures. The SDT decided not to be prescriptive in the definition of a vegetation imminent threat. Rather, the Transmission Owner should have the flexibility of defining its own procedure per the TVMP. In addition R4 has been modified and now requires the Transmission Owner to prevent vegetation encroachment of the Minimum Vegetation Clearance Distances (MVCD) as observed in real time and eliminates the use of the CCZ for this purpose.

R2. Each Transmission Owner shall implement its imminent threat procedure when the Transmission Owner has actual knowledge of such a threat, obtained through normal operating practices.

Deleted: or notification from others, that the Critical Clearance Zone is approached by vegetation to prevent an encroachment of the Critical Clearance Zone.

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Organization	Agree?	Question 11 Comment
BCTC		BCTC feels that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.

Organization	Agree?	Question 11 Comment
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Utility Arborists		The Western Utilities feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Associated Electric Cooperative Inc.	Disagree	The phrase "Critical Clearance Zone is approached" in R2 is nebulous and probably unenforceable. The determination and visualization of the Critical Clearance Zone and approaching vegetation encroachment, under field conditions, is a practice in application of theoretical conductor locations in real time. Would the Transmission Owner be found in noncompliance if evidence showed vegetation had "approached" within 20 feet, 2 feet, 2 inches or some other arbitrary distance of the CCZ and the TO failed to implement its imminent threat procedure?
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Western Area Power Administration, Upper Great Plains Region	Disagree	The CCZ as defined would very specifically outline a zone that needs to remain clear of vegetation to avoid a violation, but that specificity could be an overly burdensome concept to implement and/or monitor. Theoretically, there could be an infinite number of allowable vertical and horizontal (for outside phases) clearances depending on your location within each span. Theoretically, you may need to clear cut at mid-span (depending on retreatment intervals, growth rate, etc.) while allowing a 40 foot tree closer to the structure, along with everything in between depending on your location within the span. To fully comply with the CCZ as defined, each Transmission Owner would have to have a table of allowable vertical and horizontal clearances for every few feet on every available span length within each line section. Producing such tables

Organization	Agree?	Question 11 Comment
		would be a significant burden to each Transmission Owner, but without them, the Transmission Owner could not verify that vegetation had not encroached within the CCZ. In order to produce the tables outlined above, the Transmission Owner would need to identify what design parameter(s) are applicable for the "correct" CCZ? We remain concerned that weather conditions in excess of those parameters could lead to a vegetation contact/outage and proving that weather conditions were in excess of design criteria would be extremely difficult or impossible for all spans on a lengthy transmission line. It is not uncommon to have weather stations 50 or more miles away from points on our transmission system. In order to certify/verify compliance, the Transmission Owner would have to physically take their table to the field and verify vertical and horizontal clearances from the edge of the theoretical envelope (not the actual conductor position) for all vegetation within the span. This would be a time-consuming, burdensome, cumbersome process if Regulators are going to require specific evidence in order for the Transmission Owner to document their annual certification.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The SERC VMS recommends that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone (CCZ) and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Florida	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, precise field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. In addition, the R2 requirement for action when the imprecise and theoretical CCZ boundary is "approached" by vegetation is an even more subjective and unmeasurable. The "rate of approach" is really the key issue of concern. The rate of vegetation approach is a function of many variables including species type and site specific growing conditions. For example, a Century Plant which can grow six inches a day is obviously a much greater concern than a Lodgepole Pine on a dry mountain top which grows only a few inches a year. As such, there is no practical way to define or measure for regulatory purposes those "approach" situations that legitimately require immediate action from those "approach" situations that do not. The wording and concepts of R2 are therefore to imprecise to be used as clear requirements for Standards compliance.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Progress Energy Carolinas	Disagree	The Critical Clearance Zone as currently defined is too academic. Implementation of R2 would require field operations staff to determine the theoretical position of the line during inspections to decide whether to engage the imminent threat procedures. The academic/theoretical aspects of the Critical Clearance Zone definition are not practical or enforceable. The criteria for a violation needs to be limited to the position of the conductor in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
SERC OC Standards Review	Disagree	The SERC OCSRG recommends that R2 be deleted. Since this is a "zero tolerance" standard any

Organization	Agree?	Question 11 Comment
Group		Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Florida Power & Light	Disagree	FPL agrees that the Gallet equation is a better method to determine a Critical Clearance Zone. However, FPL does not agree with the application of the zone for several reasons outlined below. ? There are many environmental and engineering variables and assumptions included in the calculation of the Critical Clearance Zone. ? These assumptions are not clearly defined in the standard. ? Unless there is a significant intrusion into the Critical Clearance Zone, an engineer and surveyor would be necessary at all times to determine a violation. ? The success of this standard lies with a standard the field personnel can implement. When making actual trimming or removal decisions, the field personnel are not adequately skilled to do much more than make a rough guess at the Critical Clearance Zone. This standard must establish measurable and auditable parameters for field operations. ? In Requirement R2, determination of when to activate the Imminent Threat Procedure becomes unclear due to the difficulty in determining when the Critical Clearance Zone is encroached. ? As written, off ROW trees falling through the Critical Clearance Zone become a violation of Requirement R4. Unless an outage occurred, how would the utility determine that a violation occurred? In FAC 003-1 an outage of this nature is defined as Category 3 and is not a violation. Since fall-in tree interruptions have never been contributors to cascading events or blackouts they should not be a violation of a NERC standard. Consequently, as written, it is highly questionable whether this Standard is sufficiently specific and clear to be enforceable. The many questions and levels of confusion introduced with the application of the Critical Clearance Zone concept suggests that neither the industry nor NERC will ever know if compliance is met. Such a high level of ambiguity requires that the Critical Clearance Zone concept be revisited and most likely replaced with a measure that is workable for both the industry and NERC. To further this effort, FPL has outlined some alternative suggestions described in the answer to question 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

Organization	Agree?	Question 11 Comment
Southern Company	Disagree	As written, R2 requires activation of the imminent threat process when the Critical Clearance Zone (CCZ) is "approached" by vegetation. The term "approach" is vague and open to interpretation. Since vegetation is dynamic in nature, it is constantly "approaching" any pre-defined zone. There could also be many examples given of encroachments into the theoretical CCZ that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to take immediate action or ensure future action occurs on schedule. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. We are concerned this revision of FAC-003 continues to take a zero tolerance approach to compliance, which is contrary to the philosophy utilized in other NERC standards. A state of non-compliance should not exist simply because vegetation encroached within a pre-defined zone by a fractional inch, but only when an event, such as a sustained outage, occurs due to the Transmission Owner's failure to maintain adequate clearance between conductors and vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
E.ON U.S.	Disagree	E.ON U.S. suggests that R2 be deleted. Since this is a "zero tolerance" standard any Transmission Owner will remove any discovered threats to prevent outages. While we agree that the implementation of an imminent threat procedure may be a valid concept, visualization of the Critical Clearance Zone and determining an approaching encroachment is a practice in application of theoretical conductor locations in real time.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
FirstEnergy	Disagree	The CCZ is not equal to Clearance 2 in FAC-003-1. Per requirement R4, any encroachment into the CCZ is a violation of the standard even if an outage does not occur. This is too strict because it refers to a "0" tolerance even for encroachments that do not affect reliability. This can be an extremely costly standard to comply with that may or may not improve reliability. The CCZ distance is a difficult to determine from one moment to the next based upon the description and calculations outlined. The conditions on the right of way are dynamic and ever changing. It would be more proactive for the TO to focus on implementing the TVMP rather than expending time and money trying to determine if the CCZ has been violated. A better approach

Organization	Agree?	Question 11 Comment
		would be to establish a minimum clearance at all times rather than to monitor encroachment to a theoretical CCZ.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	he CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		

Organization	Agree?	Question 11 Comment
SERC Compliance Staff	Disagree	SERC staff agrees that the implementation of an imminent threat procedure may be a valid concept; however visualization of the Critical Clearance Zone and determining an approaching encroachment will be difficult from a practical matter. There also needs to be definition of what is meant by "approaching" if this is used. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. It may be better, and more reasonable to define a constant zone around a conductor that would be the same throughout the span. The clearance zone should not include the limitation that the zone cannot extend outside the active right of way.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
ITC HOLDINGS	Disagree	Just because vegetation is approaching the CCZ doesn't represent an imminent threat and should not be set to an imminent threat procedure. Implementation of R2 would require field personnel to determine the speculative position of the line during inspections to decide whether to engage the imminent threat procedures. While we agree that an imminent threat procedure should be implemented to address vegetation related imminent threats as soon as they are identified, we believe that an approach of the CCZ should not be used to generate implementation. The term "approached" does not identify a specific distance, so it's not clear to what extend vegetation would have to approach the CCZ to require implementation of the imminent threat process. ITC agrees that the implementation of an imminent threat procedure may be a valid concept, but visualization of the CCZ and determining approaching vegetation is a practice in hypothetical conductor locations in real time. This may be a good imaginary concept in understanding conductor movement but it's impractical for field applications.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tennessee Valley Authority	Disagree	TVA recommends that R2 be removed from this standard. Since this is a "zero tolerance" standard there is a very significant incentive for the Transmission Owner to inspect and plan maintenance to prevent potential outages. The Gallet Equations should be kept within the white paper solely for the TO to reference for developing maintenance and inspection cycles.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has		

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discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Exelon	Disagree	Comments: 1) In spite of the rigor associated with the Gallet equations, the definition of CCZ is imprecise as the Ratings to be used are not specified. In addition, Exelon is concerned that it will be difficult to determine the CCZ for each span under all possible operating conditions. Implementing an imminent threat procedure (R2) in combination with the CCZ may be unworkable under actual field conditions. 2) We are concerned that CCZ is only fully defined in the Technical Reference documentation and not in the standard itself. As stated in the NERC Standards Process Manual, Elements of a Reliability Standard, "Supporting documents to aid in the implementation of a standard may be referenced by the standard but are not part of the standard itself." There needs to be enough specificity as to the definition of CCZ in FAC-003-2 so that adequate documentation and evidence of compliance can be developed.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Electric Power (AEP)	Disagree	AEP agrees with the need for a TO to have an Imminent Threat Procedure and that the Transmission Operator should be immediately notified of imminent threats. However, AEP disagrees with the requirement that the Transmission Operator be notified merely because the CCZ has been approached. Vegetation approaching the CCZ does not necessarily constitute an imminent threat. It is possible that the CCZ is encroached by vegetation at the lowest point of the CCZ whereas the conductor may be at its highest point in the CCZ (potentially 20 or 30 feet away from the vegetation). This situation does not merit notification to the Transmission Operator. Please also refer to our comments regarding CCZ in AEP's responses to Questions 15 and 18.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		

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Platte River Power Authority	Disagree	Changing to the Gallet equation will not have a large impact on vegetation management operations, keeping Clearance 1 and 2 with tables developed using IEEE Standards for various voltages, line spans and altitudes is preferable. Actions should be taken to prevent an outage when vegetation encroaches Clearance 2.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover. The IEEE standard was developed for human safety purposes.		
Northern Indiana Public Service Company	Disagree	While I agree with the argument that the Gallet equatiion is a better technical or scientific method than IEEE 516 for determining realistic conductor to tree flashover distances, I do not agree that the new proposed clearance tables serve any useful purpose as a vegetation clearance standard from an operational perspective. The FAC-003-2 Technical Reference itself points to this fact when it states, "even if the exact size and shape of the C.C.Z. is known, it becomes nearly impossible in the field to correlate and accurately superimpose the C.C.Z. around the conductor." The Tech. Ref. goes on to say that "it is anticipated that many T.O.s will establish a work trigger well outside the C.C.Z." I agree wholeheartedly with that concept and believe that the Gallet clearance tables should be used by TO's to develop the more important "work trigger" or "action threshold" clearances. This revision is overly focused on C.C.A.'s that have no practical operational application while being silent to the more critical to reliability issue of "work trigger/action threshold" clearances. This needs to be addressed if we hope to be successful at achieving the goal of zero preventable tree related outages.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission		

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Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Orange and Rockland Utilities Inc.	Disagree	While we agree that the imminent threat procedure should be implemented to address vegetation-related imminent threats as soon as they are identified, we believe that an "approach" of the CCZ should not be used to trigger implementation. The term "approached" does not identify a specific distance, so it is not clear to what extent vegetation would have to approach the CCZ in order to require implementation of the imminent threat process. This is left to the discretion of individual interpretation, is confusing to field personnel, and presents compliance and auditing problems. Imminent threats which are based on vegetation clearances should be identified based on specific clearances, not undefined approach distances. In practical field application the CCZ is an invisible area that changes shape and size along the length of the conductor. It is impossible to readily identify in the field without engineering calculations and precise measurements or the use of technology such as Aerial Laser Survey (ALS) using Light, Detection and Ranging (LIDAR) technology. Therefore under normal circumstances the location, size, and shape of the CCZ and vegetation encroachments of the CCZ can only be roughly estimated. Even with the use of ALS, which is relatively accurate, information is often not available for months after the survey flight. We believe that under normal circumstances imminent threats which are based on vegetation clearances should be identified in terms of specific distances from the conductor. While it is not possible for an inspector to readily identify a vegetation encroachment of the CCZ in the field, an inspector could more easily estimate a specified short distance between a conductor and vegetation in real time and initiate implementation of the imminent threat procedure based on that assessment. This assessment would be significantly more accurate than attempting to measure the distance between vegetation and the CCZ, which is not visible and constantly changes size and shape throughout the span. In cases where the Transmission Owner chooses to deploy ALS, the CCZ rather than the conductor could be used as the reference because in most cases the CCZ could be identified relative to approaching vegetation with a reliable degree of accuracy. Still a specific distance should be used to trigger implementation of the imminent threat procedure because of the issues previously raised with the use of the word "approached".
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
American Transmission Company	Disagree	ATC believes that the Critical Clearance Zone (CCZ) is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or

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		even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two to three times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently written, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented or monitored, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance. Requirement R2 could be rewritten as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage would promote the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Ameren	Disagree	The CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation "approaching" the CCZ does not constitute an imminent threat. In fact, the moment after vegetation is cut, it begins again to "approach" this zone. It may be months to years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance. As R2 is currently stated, a

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		Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within some observed field distance.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Nebraska Public Power District	Disagree	The CCZ is a good concept to explain the flight path of a conductor under all conditions but it would be impractical to use in the field. There are too many variables to consider and an encroachment does not constitute an immediate threat.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Manitoba Hydro	Disagree	The imminent threat process trigger should be well defined, and the vague "approaching" terminology needs to be changed. Imminent threat implies and that an elevated risk of contact exists. That is not the case if the vegetation is merely approaching the CCZ. The objective of the overall Vegetation Management program is to prevent an encroachment. The imminent threat procedure should be triggered by discovery of an encroachment into the CCZ. Even when an actual encroachment into the CCZ occurs - while the odds of an outage event have increased - the likelihood of a contact is still minimal, as other environmental factors still need to be in place (i.e. high temperature and/or high wind conditions).If this approach to an imminent threat process trigger, then the violation of this requirement implies a violation of R4, which prohibits the encroachment of the CCZ, and therefore either R2 or R4 could be removed, or they could be combined into one requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consumers Energy Company	Disagree	Absolutely disagree! The Gallet formula distances do not provide adequate protection of the system. The "Critical Clearance Zone" concept is not workable in the field. Every foot of every span would have a different

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		CCZ that cannot be measured in the field without survey type equipment and knowledge of current line loadings. The clearance requirement needs to be uniform along the span for field crews to effectively achieve compliance. It appears that the drafting team hopes to minimize violations of vegetation violating FAC-003-1 Clearance 2 distances by decreasing the clearance distance between the conductor and vegetation using the Gallet formula. If NERC believes that FAC-003-1 Clearance 2 distances are too conservative, then the Gallet formula distance needs to be increased by some multiplier (2 or3) to achieve adequate safeguard for growing vegetation. Most trees in the United States in the size range that could exist beneath conductors achieve height growth of 3 feet or more annually. A tree in May may have adequate clearance per the proposed CCZ and in July violate that clearance causing an outage. Therefore, if the CCZ is to remain as is then the transmission owner/operator must have a defined imminent threat distance considerably greater than the CCZ and must be great enough that field personnel can safely remove the threat without de-energizing or de-rating the line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
Pacific Gas & Electric Co.	Disagree	PG&E agrees the Gallet equation is superior to IEEE 516 and the imminent threat procedure is a critical component of the standard but disagrees that initiation of the procedure be based on such ambiguous language as "approaching the CCZ". Approaching could be any and all vegetation that is live and growing and CCZ is a theoretical calculation not a real time event. As written, the standard would require the TO to initiate an emergency action when such action may not be warranted or necessary to prevent an outage. PG&E recommends using a clearly defined and measureable threshold to determine when the imminent threat procedure must be initiated. A reasonable threshold would be 3 times the Gallet clearance distances referred to in Table 1 or when vegetation is threatening to fall into or otherwise impact a line.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives.		

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San Diego Gas & Electric	Disagree	We do not agree with replacing Clearance Zone 2 with the Critical Clearance Zone. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY is in favor of using the Gallet equations as they provide a more realistic clearance distance for vegetation. We understand and agree that establishing a Critical Clearance Zone (CCZ) would provide the specific area that a conductor could possibly travel through during various field and weather conditions but we do not agree that this is the most practical approach. The main issue is that the wording '...the Critical Clearance Zone is approached by vegetation.....' is very vague and left open to wide interpretation which causes inconsistency and confusion throughout the industry. The CCZ changes throughout the length of each conductor in each span so a field inspector's job and an auditor's job become much more complicated when trying to confirm compliance when vegetation is present in the Actiove ROW. We feel that the time spent trying to measure and calculate the CCZ and then confirm compliance would be better spent initiating a response plan to safely remove the vegetation. The imminent threat procedure would only be implemented if vegetation encroaches beyond a specific distance from the conductor, not as it approaches the theoretical CCZ. Advanced technology would be required if a vegetation approach distance to the CCZ was to be calculated in the field. This is a very costly and time consuming requirement and does not efficiently meet the Standard's goal of ensuring reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Duke Energy Corporation	Disagree	No. Duke believes that the CCZ is a good theoretical concept to aid industry in understanding the overall movement of conductors, but it is an impractical concept for field application. Due to the variability in the size of the CCZ as you move along a conductor, as well as changes from span to span or even line to line due to design parameters, loading or weather-related issues, the CCZ concept should not be tied to an imminent threat procedure. Vegetation approaching the CCZ does not constitute an imminent threat. It may be years before this vegetation ever gets to a proximity distance from the conductor to be within a "spark-over" distance

Organization	Agree?	Question 11 Comment
		as defined by the Gallet equations. Requirement R2 should support the purpose of this standard by requiring implementation of the Vegetation Imminent Threat Procedure when the Transmission Owner has visual, field knowledge that vegetation is encroaching upon a conductor within some specific distance that is a multiple of the Gallet distances referenced in Table I of FAC-003-2 (to be conservative we suggest two times the Gallet distances). Failure to implement the Vegetation Imminent Threat Procedure in such instances would be a violation of R2.As R2 is currently stated, a Transmission Owner cannot comply with R2 unless the imminent threat procedure is continuously being implemented, because vegetation that is growing is always approaching the CCZ. "Approaching the CCZ" cannot be the trigger for implementation of the Vegetation Imminent threat Procedure. Instead, the trigger should be an encroachment within an observed distance from vegetation to conductor that is twice the Gallet distances in Table I. Requirement R2 could be reworded as follows: ?Each Transmission Owner shall implement its Vegetation Imminent Threat Procedure when the Transmission Owner has knowledge, obtained through normal operating practices or notification from others, that vegetation is encroaching upon a conductor within a distance that is twice the Gallet clearance distances referenced in Table I." Using a multiple of the Gallet distances provides a safety factor. Assessing a violation for failure to appropriately implement the Vegetation Imminent Threat Procedure or for a sustained vegetation-related outage incents the proper behavior.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.**		
Entergy Services	Disagree	: 1. Entergy suggests that the requirement for activation of the vegetation imminent threat process should not be tied to the Critical Clearance Zone and that the each entity should define the activation of their vegetation imminent threat process. Tying the activation of the imminent threat process to the Critical Clearance Zone is limited in that this criterion does not address the possibilities of vegetation falling into the line or Critical Clearance Zone. 2. In the sentence "Critical Clearance Zone approached by vegetation" the use of "approached" is subjective and not specifically quantifiable. Effective, uniform activation of the imminent threat process will require objective measurement criteria. 3. The standard needs to include a clear statement to the effect that when the Transmission Operator is notified of a potential vegetation problem, obtained by normal operations and inspections, the entity will

Organization	Agree?	Question 11 Comment
		activate the Vegetation Imminent Threat Process. 4) This requirement, as stated, is redundant. The requirements for maintaining the Critical Clearance Zones and / or avoiding vegetation outages, and the associated Violation Risk Factors and Violation Severity Levels, already reinforce the desired behavior of the entity to identify and mitigate any potential issues before the possibility of vegetation causing an outage.
Response: Thank you for your comment. **1) The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. These changes may address your concerns.** **2) Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The word, "approached" is not used in the revised standard.** **3) Requirement R1 Part 1.4 specifies the TVMP have an Imminent Threat procedure that includes notification of the responsible control center.** **4) The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
Pepco Holdings, Inc	Disagree	R5, R6 and R7 make this requirement redundant and unnecessary - it should be deleted. It is largely unenforceable and does not make the standard clear, specific and regulatory enforceable. Further, PHI believes the concept of enforcing no encroachment into the Critical Clearance Zone is a flawed approach.
Response: Thank you for your comment. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. **The SDT believes that having to implement an Imminent Threat procedure is proactive behavior and is in support of prevention of outages.**		
JEA	Disagree	The use of Gallet equations is not practical either for field use or for demonstrating compliance.
Response: Thank you for your comment. The SDT chose to use Gallet equations over IEEE primarily because Gallet is more appropriate for determining the probability of flashover and the SDT believes holds distinct advantages for use in vegetation management applications. IEEE 516 is developed for human safety purposes.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing to the Gallet equation will not have a large impact on its vegetation management operations, so we have no concerns. We agree with R2, but feel that this clause makes R4 redundant, as per

Organization	Agree?	Question 11 Comment
		our discussion under Comment # 15 below. We recommend the removal of R4 entirely from the standard.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
WECC	Agree	Yes but the wording is ambiguous. Vegetation under a transmission line is always "approaching" or growing towards the transmission line. Entities should define a specific distance greater than the Critical Clearance Zone when they are required to implement their Imminent Threat Procedures.
Response: Thank you for your comment. The proposed standard revision specifies a "Minimum Vegetation Clearance Distance" as a starting point and TOs may apply greater distances at their discretion in order to trigger implementation of the Imminent Threat procedure. The word, "approaching" is not used in the revised standard.		
Baltimore Gas & Electric Company	Agree	Again, each utility is responsible and accountable for it's actions. The Gallet clearances are a much better approximation of a true spark gap than the present requirement. Without a clearance one requirement, the closer tolerance produced by the Gallet equation will leave little room for error when a line is at or approaching it's max. engineered sag. When vegetation gets in the new CCZ (if adopted), it will be likely that an outage will be imminent. With the present clearance 1 and clearance 2 requirements, there is more of a buffer for encroaching vegetation.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4. The proposed standard revision specifies the MVCD as a starting point and TOs may apply multiples at its own discretion in order to achieve its TVMP objectives and adhere to applicable safety standards.		
CenterPoint Energy	Agree	We agree with replacing IEEE 516 standard distances with the Gallet equation standard distances. However, the term "Critical Clearance Zone" refers to the "limits of the Active Transmission Line Right-of-way" which has no specific definition as to its limits within the proposed revised Standard. (See comments to Q3 above.) R2 should be reworded to coordinate with R1.4. (See comments to Q4 above.)

Organization	Agree?	Question 11 Comment
Response: Thank you for your comments. Please see our responses to Questions 3 and 4 comments as well as the summary consideration for this question Based on stakeholder comments, the SDT made significant modifications to Requirement R2 and removed the concept of the CCZ.		
Salt River Project	Agree	Although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method designed specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below. In addition, we feel this clause makes R4 redundant, as per our comments under Comment #15 below.
Response: Thank you for your comment. The Gallet equations indeed are useful in tower design; however it is not exclusively for that purpose. The decision whether to use Gallet is not contingent upon testing and none were considered or conducted. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.		
Southern California Edison Company	Agree	Q11: SCE agrees in part with proposed R2. The use of the Gallet equation and the replacement of the existing Clearance 2 requirement with the Critical Clearance Zone is acceptable. However, SCE strongly disagrees with establishing a separate requirement for implementing an imminent threat procedure should there be an encroachment of the Critical Clearance Zone because it forms the basis of an unnecessary zero-tolerance enforcement policy. Read in context with corresponding Measure 2, R2 appears to require Transmission Owners to prove that a Critical Clearance Zone encroachment did or did not occur and also prove that that an imminent threat procedure was or was not properly invoked. Although SCE agrees that CCZ encroachments should be addressed timely, we disagree with the notion and underlying assumption that a CCZ incursion will always lead to a flash-over or a vegetation-to-line contact. If the goal of FAC-003-2 is to prevent sustained outages (due to vegetation-to-line contacts) that could lead to Cascading, emphasizing “prevention” is understandable, however, enforcing prevention measures is an entirely different matter. Under the proposed requirements, a vegetation-to-line contact could conceivably represent two distinct violations of FAC-003-2. SCE believes this type of regulatory double jeopardy is patently unfair and forcing Transmission Owners to prove a CCZ encroachment did or did not occur is equally unfair and unenforceable. Because R1.4 adequately addresses the Transmission Owner’s responsibility regarding the implementation of an imminent threat procedure, SCE respectfully recommends that proposed R2 and corresponding M2 be removed from

Organization	Agree?	Question 11 Comment
		FAC-003-2.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Buckeye Power, Inc.	Agree	I agree with R2. I like the language changes, but decreasing the clearances will not improve reliability.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Great River Energy	Agree	GRE agrees and believes that the Gallet equation yields a less subjective measurement. GRE believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the Critical Clearance Zone (CCZ). It is GRE's opinion that approaching the CCZ is subjective and as such very difficult to enforce.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	Attachment 1 is very conservative. I think that the clearance distances shown on the attachment should be expanded to create, in effect, a standard that reflects maximum line loading and maximum line sag. I would also like to see some flexibility built into the process so that the Transmission Owner and the USFS could negotiate some consideration for vegetation growth rates. The end result would generate a standard that would give the Transmission Owner the security of knowing that vegetation would not grow into the potential arcing zone for some reasonable amount of time - some kind of entry cycle.
Response: Thank you for your comment. The SDT has retained the use of Gallet equations in the proposed draft standard revision but has discontinued the use of the CCZ. The SDT received a substantial number of negative comments on the matter of R2 and the CCZ. In response, the SDT		

Organization	Agree?	Question 11 Comment
modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Measure M2 requires that the entity have evidence showing dates and activities accomplished to meet the R2 implementation requirement. The SDT notes that the proposed standard revision does not preclude the USFS and the TO from negotiating consideration for vegetation growth rates and in fact it is a good idea.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: Thank you for your comment. Please see the summary response. Many commenters disagreed with this requirement and it has been substantially modified.		
Bonneville Power Administration	Agree	BPA agrees with R2, but refer to comments submitted regarding R4 (please see our response to Question #15) for related recommendations to R2.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
MRO NERC Standards Review Subcommittee	Agree	The MRO agrees and believes that the Gallet equation yields a less subjective measurement. The MRO believes R2 should be modified to be more definitive. The imminent threat procedure should be implemented when vegetation “enters” the critical clear zone. Fines and violations for approaching the zone is not measurable or enforceable. The MRO believes that "approached" is subjective and not enforceable and should be removed from the requirement.
Response: Thank you for your comment. The SDT modified R2 to remove the use of the CCZ to trigger Imminent Threat procedure implementation. Requirement R2 now requires the Transmission Owner to implement its imminent threat procedure upon discovery of such a threat. . The Critical Clearance Zone has been replaced with Minimum Vegetation Clearance Distance (MCVD) in R4.		
Northern California Power Agency (NCPA)	Agree	
Santee Cooper	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	

Organization	Agree?	Question 11 Comment
Arizona Public Service Company	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Kansas City Power & Light	Agree	
National Grid	Agree	
Long Island power Authority	Agree	
Central Maine Power Company		No comment

12. The Standard Drafting Team revised the spark-over (also referred to as “flashover”) distance thresholds utilizing technically-equivalent Gallet equations in lieu of IEEE 516 minimum air insulation distance (MAID) calculations that were used in FAC-003-1. The rationale is that the minimum air insulation distances in IEEE 516 were safety clearances developed under laboratory conditions and thus there exists concern these distances may be too conservative to apply to lines operating in actual field conditions. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (90%) agreed with this change. The minority view favored the continued use of IEEE 516 and four responders advocating removing the tables from the standard.

After reviewing the industry comments, the SDT continues to support the merits of using the Gallet equations and maintaining the tables in the standard. IEEE 516 values are safety clearances developed under laboratory conditions and thus these distances are inappropriate for vegetation spark-over clearances associated with lines operating in actual field conditions. In addition, IEEE Standards are subject to change which the SDT did not desire to have the Vegetation Reliability associated with an IEEE Standard that may change without proper consideration of the impact to the Vegetation Reliability Standard.

By using the Gallet distances, the SDT feels this is a technically sound, independent value that represents a true spark-over threshold distance. One must remember this is a minimum distance and the new requirement of 1.6 specifies the Transmission Owner develop a maintenance strategy to ensure these clearances are never violated.

Organization	Question 12	Question 12 Comment
SERC Compliance Staff	Disagree	While the actual sparkover distance may be more correctly calculated using the Gallet equations, SERC staff believes it is a less conservative approach to the goal of preventing vegetation related outages. If the concept of the CCZ will remain in the standard, we suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the theory behind the establishment of a CCZ. However, the CCZ will continue to be a very difficult, if not impossible, aspect of the standard to implement from the perspective of practical application and compliance enforcement.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document. The revised standard does not use the concept of the CCZ.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.

Organization	Question 12	Question 12 Comment
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Exelon	Disagree	Comments: By using the Gallet equations, the draft standard appears to support reducing the clearance requirements as compared to IEEE 516. Given what we believe would be the difficulties in applying the clearances as developed using the Gallet equation method, we question if dropping the IEEE 516 guidance could have the unintended consequence of reducing reliability.
Response: The SDT thanks you for your response. The reduction in the clearance distances is due to applying smaller transient over-voltage factors and not due to using the Gallet equations. The SDT feels that using the reduced over-voltage factors is a more realistic approach than using the maximum factors in version 1. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Northern Indiana Public Service Company	Disagree	If T.O.'s are serious about public safety and potential electrical hazards or are required to comply with NESC/IEEE safety standards, then the greater, more conservative clearance distances must apply. On an complex issue where the aerial distances between live conductors and trees are dynamic and changing, I would prefer to be on the side of caution and on the side of safety. Given the history of cascading blackouts due to preventable tree contacts, there is a need to be conservative with the standards. I don't see it being in the public interest to argue that established minimum air insulation distances are inappropriately restrictive when applied to UVM.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Consumers Energy Company	Disagree	The Gallet distances severely lessen the reliability of the transmission system since there is not a define imminent threat distance and the Clearance 1 distances have been removed from this draft. The IEEE 516 distances provided a safety margin to allow for vegetation to grow and not be a reliability risk. A transmission owner/operator of a moderate size could not effectively inspect often enough during the growing season to protect lines from outages when trees are permitted to approach the Gallet formula distance and not be a violation. Such close distances would permit utility management to severely cut vegetation management budgets and allow trees to grow for 1-2 years beyond their scheduled maintenance cycle and not be in violation. But, 2-3 years after the budget cut, the field operation would be faced with an insurmountable amount of trees needing addressed and limited timeframes to complete the work. This is basically how the blackout occurred and this standard decreases the requirements to allow this to happen again.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also		

Organization	Question 12	Question 12 Comment
consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
Baltimore Gas & Electric Company	Disagree	As noted in 11 above, the Gallet equation would appear to be a much closer approximation of the actual spark gap/flashover distance. It seems as though the new std. is making the protective zone around the conductors smaller by replacing the Clearance 2 requirement with the CCZ, while at the same time eliminating any other type of consideration for how much clearance needs to be achieved while trimming. All things being equal, if the only demarcation for when vegetation is a threat to the lines is the clearance 2 or CCZ areas, it would make sense to have this area be larger rather than smaller. Accordingly, I would recommend that the Clearance 2 value continue to be used instead of the Gallet equation-created CCZ.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP. Note that the revised standard does not use the concept of the CCZ.		
SERC Vegetation Management Subcommittee (VMS)	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re-numbered or deleted altogether. We suggest that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
SERC OC Standards Review Group	Agree	Developing minimum sparkover distances in this standard is a superior approach for the stated reason in question 12. In addition, referring to tables and values in another standard is problematic if the referenced standard is revised and the tables are re- numbered or deleted altogether. The SERC OOCSRG suggests that the tables based on the Gallet equations be removed from the standard and be kept in the technical white paper solely to assist in developing a common understanding of the threshold for taking actions.
Response: The SDT thanks you for your response. The SDT feels that the tables are an important component and should be part of the standard. The supporting documentation for the derivation of the tables resides in the technical reference document.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		

Organization	Question 12	Question 12 Comment
American Electric Power (AEP)	Agree	AEP agrees that the Gallet Equation method is a reasonable and appropriate replacement for the IEEE 516 method.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, so we have no concerns.
Response: the SDT thanks you for your comments.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	See comment for Question 11.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Salt River Project	Agree	As commented in Comment #11 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your response. The SDT searched for a method other than the laboratory condition based IEEE 516 method to determine minimum spark-over distances. The Gallet equations were derived for both wet and dry conditions and have been successfully used in many design applications. The SDT feels that using these equations to derive these minimum distances is a conservative approach. We also expect that the TO must also consider sag, sway, growth, environmental conditions and other factors when developing clearances for an effective TVMP.		

Organization	Question 12	Question 12 Comment
Buckeye Power, Inc.	Agree	I understand the reasoning for the change, but I do not see how decreasing clearances will increase reliability.
Response: The SDT thanks you for your response. The Gallet equations are only one of the factors in developing clearances. The utility must also consider sag, sway, growth, environmental conditions and other factors when developing an effective TVMP.		
British Columbia Transmission Corp	Agree	BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern California Edison Company	Agree	Q12: No comments.

Organization	Question 12	Question 12 Comment
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	

Organization	Question 12	Question 12 Comment
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	
JEA	Agree	
Independent Electricity System	Agree	

Organization	Question 12	Question 12 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Great River Energy	Agree	

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13. The Standard Drafting Team applied a transient overvoltage factor (T) of 1.4 and 2.0 for ac voltage classes of 345kV and above and sub-345kV facilities, respectively. Version 1, using the IEEE 516 method, assumes a maximum transient overvoltage value. The Standard Drafting Team asserts that in this application of steady-state flashovers and due to the design attributes of higher voltage systems, a lower T factor is applicable. Do you agree with this? If not, please explain.

Summary Consideration: The majority of responders (93%) agreed with this change. Two responders commented that they use a more conservative transient over-voltage factor in their design.

The SDT chose its transient over-voltage factors ("T") as being the most appropriate values for the industry as a whole. The majority of industry stakeholder comments supported this decision. It is permissible to use more conservative values if the Transmission Owner so desires.

Organization	Agree ?	Question 13 Comment
BCTC		BCTC feels that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your response.		
Tennessee Valley Authority	Disagree	TVA agrees with this concept however as stated in Comment Question 11 response, this should be an element of the White Paper and should not be in the Standard Requirement.
Response: The SDT thanks you and refers you to the response to Question 11.		
Exelon	Disagree	We disagree with the T factors that are proposed as our design is more conservative.
Response: The SDT thanks you and also acknowledges that various utilities may employ various T factors in their line designs. However, the SDT chose this value as the most appropriate value for the industry as a whole. Individual Transmission Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
Manitoba Hydro	Disagree	Manitoba Hydro has historically designed the ROW clearance requirements based on an operating limitation of not switching during extreme wind conditions, therefore, beyond a wind pressure of 230 Pa, our design does not account for switching surge over voltages. We do however, agree with the use of overvoltage factors

Organization	Agree ?	Question 13 Comment
		as described above for wind conditions of less than 230 Pa.
Response: The SDT thanks you for your comments. Industry as a whole. Individual Transmisssion Owners are free to establish larger zones around the conductor than that established by the new MVCD. MVCD as currently drafted establishes a minimum value, not the only value.		
National Grid	Disagree	No opinion.
Response: The SDT thanks you for your comments. The SDT believes that it has chosen an approach that is the most appropriate method for the industry as a whole.		
SERC Vegetation Management Subcommittee (VMS)	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
SERC OC Standards Review Group	Agree	See comments in #12 above.
Response: The SDT thanks you for your comments. See response to #12.		
Salt River Project	Agree	As commented in Comments #11 & #12 above, although we agree that using the Gallet equation is more definitive than using IEEE 516, we still question from an engineering prespective as to how and why this method was chosen. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a tower under normal conditions. Because this is not a method design specifically for vegetation management, was there any physical testing involved in choosing this approach, such as testing in both wet and dry conditions? We would recommend additional information to clarify this method to use for vegetation management. See additional comments in Comment #18 below.
Response: The SDT thanks you for your comments. No physical testing was utilized by the SDT; however, the Gallet Equation method and its explanation in the White Paper do have their basis in physical testing in both laboratory and field conditions. The Gallet Equation method is not solely applicable to tower structure design, but to any application requiring spark-over calculations. The SDT believes that the Gallet Equation method holds distinct advantages over the IEEE 516 method for use in vegetation management applications.		
Western Utility Arborists	Agree	The Western Utilities feel that changing this will not have a large impact on its vegetation management

Organization	Agree ?	Question 13 Comment
		operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
American Electric Power (AEP)	Agree	AEP agrees that the choice of transient overvoltage factors is sufficiently sound.
Response: The SDT thanks you for your comments.		
Platte River Power Authority	Agree	Changing this will not have a large impact on vegetation management operations, we have not concerns.
Response: The SDT thanks you for your comments.		
City of Tallahassee	Agree	As long as we do not have to have evidence of using the calculation! We should be able to use Table I as provided.
Response: The SDT thanks you for your comments.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Agree	We feel that changing this will not have a large impact on its vegetation management operations, so we have no concerns.
Response: The SDT thanks you for your comments.		
Southern California Edison Company	Agree	Q13: No comments.
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Progress Energy Florida	Agree	

Organization	Agree ?	Question 13 Comment
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Central Maine Power Company	Agree	
Northern California Power Agency (NCPA)	Agree	

Organization	Agree ?	Question 13 Comment
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Consumers Energy Company	Agree	
Pacific Gas & Electric Co.	Agree	
San Diego Gas & Electric	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Arizona Public Service Company	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree ?	Question 13 Comment
JEA	Agree	
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	
Baltimore Gas & Electric Company		I have no expertise to respond to this question.
Northern Indiana Public Service Company		No comment.
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM		Don't know!

14. R3 has been added to clarify that conduction of inspections is a separate requirement from specifying the frequency that inspections will occur. Do you agree with R3? If not please explain.

Summary Consideration: The majority of commenters (85%) were in favor of the standard as written. There were minority comments that wanted a reformatting of the standard to put documentation and implementation side by side. Following the directives in FERC order 693 and the SAR to bring the standard in line with the Sanction Guidelines, the SDT created a separate requirement, R3 that explicitly requires inspections be conducted. This is to differentiate R3 from Requirement 1, Part 1.2. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.

Organization	Agree?	Question 14 Comment
BCTC		BCTC understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Western Utility Arborists		The Western Utilities understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT considered other sequence options and suggest a new sequence for the industry to comment upon. See related question in the second Comment Form.		
Progress Energy Florida	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Progress Energy Carolinas	Disagree	The standard has established a threshold of compliance. For consistency, compliance should be measured at the threshold not a Registered Entities program requirement.
Response: The SDT thanks you for your comments. R3 clarifies that the inspections in the TVMP are to be conducted. The TVMP defines a Transmission		

Organization	Agree?	Question 14 Comment
Operator's standards. The general application of NERC standards is that a Transmission Operator is to adhere to the standards it establishes.		
Southern California Edison Company	Disagree	Q14: SCE does not agree with the inclusion of proposed R3 and believes it should be replaced with a modified version of proposed R8.SCE respectfully suggests that proposed R8 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your comments. Inspections are a key element of an effective TVMP. The SDT therefore decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. In addition, addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
San Diego Gas & Electric	Disagree	The information should not be separated. It will be much easier to follow if the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Edison Electric Institute	Disagree	Consistent with previous comments, NERC should respond to FERC Order No. 693 Paragraph 721 regarding compliance audit procedures to identify appropriate inspection cycles.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Your comment has been forwarded to NERC staff. The Reliability Standard Audit Worksheet is where the FERC Order is addressed with respect to compliance audit procedures to identify appropriate inspection cycles.		
Baltimore Gas & Electric Company	Disagree	If frequency of inspections are required to be specified, it is implied that the inspections will follow. I suggest that R3 be eliminated and R1.2 be reworded to say: "Vegetation inspections shall occur at least once per year, or more frequently as dictated by local and environmental factors. Specify the frequency of when vegetation inspections will occur."

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs. The STD believes that the phrase "Specify a vegetation inspection frequency…" adequately requires the Transmission Operator to ". . . .specify the frequency…"		
JEA	Disagree	See comment from #3.
Response: The SDT thanks you for your comment. This was addressed in the response to question 3.		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments stated in Comments #4 & #6 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRF and VSLs.		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 14
Response: The SDT thanks you for your comment.		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comment.		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak schedule and higher sanctions and penalties to be assessed for not implementing schedules. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Arizona Public Service Company	Agree	APS understands that it's possible to have a schedule and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the schedule is kept together with the requirement to implement it.

Organization	Agree?	Question 14 Comment
Response: The SDT thanks you for your comment. The SDT decided to explicitly require that inspections be conducted in accordance with the Transmission Owners' requirements. Addressing inspections separately allows for appropriate assignment of VRFs and VSLs.		
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
SERC OC Standards Review Group	Agree	
Florida Power & Light	Agree	
Santee Cooper	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	

Organization	Agree?	Question 14 Comment
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	
Midwest ISO Stakeholders Standards Collaborators	Agree	
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	
Exelon	Agree	
Central Maine Power Company	Agree	
City of Tallahassee	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Tampa Electric Company	Agree	
Orange and Rockland Utilities Inc.	Agree	
American Transmission	Agree	

Organization	Agree?	Question 14 Comment
Company		
Ameren	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Pacific Gas & Electric Co.	Agree	
Hydro One Networks Inc.	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Duke Energy Corporation	Agree	
CenterPoint Energy	Agree	
Entergy Services	Agree	
Pepco Holdings, Inc	Agree	

Organization	Agree?	Question 14 Comment
Independent Electricity System Operator	Agree	
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

15. Several alternatives to R4 were considered by the drafting team. The drafting team explored these significantly different alternatives at length. They are outlined below to provide background to industry during this comment period. (Please refer to pages 22-32 in the Technical Reference Document on the Critical Clearance Zone for further background for this question.) Do you agree that R4 is written in the most effective way to achieve the purpose of the standard? If not, what do you propose as an alternative to R4 that would ensure a level of reliability equal to or better than FAC-003-1?

As written, R4, a new requirement, stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. If vegetation enters the Critical Clearance Zone, a violation will have occurred, regardless of the actual proximity of the vegetation to the conductor at the time. Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at any time during the annual compliance period. This will require the time and effort to postpone vegetation maintenance to perform field investigations and document all possible encroachments.

One alternative to R4 required immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the imminent threat process was not successfully implemented.

Another alternative was a tiered approach. This tiered approach involved a "per thousand mile" metric to determine when a violation had occurred and the severity of the violation. This metric was an attempt to equitably account for varying exposures that exist due to widely ranging system sizes.

Summary Consideration: Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.

Ninety-four percent of the commenters disagreed with the proposed alternatives. The SDT classified the comments into 44 different concepts with many commenters weighing in on several concepts. For 37 commenters the dominant concept was "Measure M4 requires proof of no encroachments, i.e., "prove a negative", compliance certification is difficult." Below is a redlined version of R4. reflecting the changes that were made by the SDT.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances ("MVCD") listed in Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating with the following exceptions: *[Violation Risk Factor VRF= Medium][Time Horizon – Real Time]*

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- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from natural disasters.[2]
- Encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from human or animal activity.[3]
- Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.

The SDT further weighed the NERC interpretation of the vegetation management standard during FERC's consideration of proposed FAC-003-1: A vegetation-related transmission line outage as a result of vegetation that has grown into the pre-defined clearance zone is a violation of the standard. The Commission adopted that interpretation when it approved NERC's proposed reliability standards. It stated, "FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions."4

In reviewing the comments and the FERC opinion the SDT considered 4 options:

- Re-word R4 and keep R4 the way it was originally intended (violation would only be if you had the outage) (Alternative B of Question 15**) {implies that R5, R6, & R7 are retained}
- Remove R2 and R4 from the standard. Keep the Critical Clearance Zone concept in the white paper.
- Remove R4 from the standard and revise R2 to have a "trigger distance" for implementation of the imminent threat process. Keep the Critical Clearance Zone concept in the white paper. Team would need to consider the true definition of an imminent threat.
- Return to the Clearance 2 concept. But define (somehow) that this is a "real time" violation only. Distance could be defined as the Gallet distance or a multiple of the Gallet distance.

The SDT made the following changes in line with bullet 4.

R4. Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, with the following exceptions:

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from natural disasters.[4]

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[2] 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.

[3] 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.

- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from human or animal activity.[5]
- Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation.

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Organization	Agree?	Question 15 Comment
PJM Interconnection		The current version of this standard, FAC-003-1, kept the subject of vegetation outside of the Rights of Way in the standard. Why are outside of Rights of Way vegetation issues not mentioned in FAC-003-2, or some responsibility for looking for outside of Rights of Way imminent threats or issues requiring corrective action plans not addressed?
Response: The SDT thanks you for your comments. Trees outside of the right of way should be identified and removed as necessary as they are identified as a threat to the reliability of the line. This function should be part of a vegetation management program as a follow up to the inspection process. Any vegetation that could pose a threat to the reliability to the line found during the inspection process should be remedied. The purpose statement for FAC-003-2 states that the standard is intended to improve the reliability of the electric transmission system by preventing vegetation related outages that could lead to Cascading.		
BCTC		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. BCTC strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, BCTC recommends removing R4 from the standard entirely.

[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.

Organization	Agree?	Question 15 Comment
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Associated Electric Cooperative Inc.	Disagree	Associated Electric Cooperative Inc believes this requirement, as written, is unreasonable since it would prevent (or at least result in noncompliance) the intrusion within the Critical Clearance Zone (CCZ) of anything or anyone, including qualified line workers and their tools. It is suggested the words "of vegetation" be added between encroachment and within. The requirement would then read, "Each Transmission Owner shall prevent encroachment of vegetation within the Critical Clearance Zone of its applicable lines with the following exceptions:" The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome, requiring engineering calculations and possibly the need for precision measurements. The Transmission Owner (TO) cannot demonstrate compliance with the Requirement and its companion Measure, M4, since a negative cannot be proven. Therefore, since the TO must demonstrate compliance (guilty until proven innocent), it is automatically in violation of the Standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The SDT, for clarity, did add the phrase "of Vegetation" as requested.		
NPCC	Disagree	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". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors

Organization	Agree?	Question 15 Comment
		(VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ . The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and would best support the purpose of the Standard.

Response: The SDT thanks you for your comments. The SDT concurs that the use of ALS – LiDar technology, while expensive, could enhance reliability. However several team members have made the investment and concur that the technology including interpertation software are not sufficiently mature to be put in a standard. In addition in some cases it would not be cost justifiable over traditional methods of inspection. During the course of our deliberations the team questioned both FERC and RE staff's response to a utility finding encrochments with ALS technology and concluded the auditor would not forgive encrochment even though the Transmission Owner went to extraordinary means to find the encrochment.

Initially the team approached the FERC staff in a meeting in Washington with a proposal that an encrochment not be a violation if the Transmission Owner implemented the imminent threat procedure successfully before an interruption occurred. The concept was rebuffed by the FERC Staff as a step

Organization	Agree?	Question 15 Comment
backwards from version 1. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because Standard revisions to already approved standards may not lead to less emphasis on reliability.**		
Western Area Power Administration, Upper Great Plains Region	Disagree	R4 as proposed would do nothing to improve the reliability of the BES. In fact, we believe that R4 (as currently proposed) would impose significantly more stringent requirements than most Transmission Owners have interpreted FAC-003-1 to require. We believe that if the proposed interpretation would have been offered under FAC-003-1 that there would have be a great backlash against that Standard. It is our believe that current annual certifications of compliance for FAC-003-1 by Transmission Owners don't use "any infringement of the CCZ by any piece of vegetation at any time" as their measure for compliance. It could be argued that this proposal would actually do more to curtail accurate reporting of potential violations. We believe that making an infringement into the CCZ a violation and having that violation carry a six (or seven) figure fine would do more to discourage accurate reporting than any other system under discussion. Making the Transmission Owner prove that an incursion into the CCZ didn't happen would force an inventory of every inch of the R/W which is a gigantic waste of resources. Being tasked with proving that something didn't happen could be compared with our justice system declaring suspects will be considered guilty until they are proven innocent. This is a flawed and blatantly unfair concept and not a productive way of attaining the Purpose stated in this document. Western (UGPR) is disappointed by the "zero tolerance" nature of this document and its interpretation that "any infringement of the CCZ by any piece of vegetation at any time" constitutes a violation. We are not aware of any other NERC standard that is zero tolerance and question why vegetation is singled out to bear the brunt when several other factors could contribute to a system cascading event (i.e. relay problems, system configuration, operator issues, etc). In summation, we believe that a zero tolerance document being applied with "guilty until proven innocent" principles would do much to create an increasingly adversarial relationship between regulators and the industry.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	The concept of the CCZ is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining

Organization	Agree?	Question 15 Comment
		an encroachment into the CCZ is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC VMS believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the CCZ concept be kept in the technical white paper and that all references to the CCZ be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Progress Energy Florida	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Kansas City Power & Light	Disagree	As proposed, Requirement R4 and corresponding Measure M4 will be highly subjective and impractical for the industry to implement. The determination of a violation due to encroachments into the Critical Clearance Zone will be subjective in nature due to field judgments, is random and not initiated by a known system event. It also will not be feasible for utilities to fulfill R4 requirements to ensure and provide evidence that any encroachments into Critical Clearance Zones have not occurred on their system throughout the year. Requirement R4 is not required since in the remaining requirements of FAC-003-2 contain the principal elements for compliance in ensuring the reliability of the bulk power system related to vegetation management of the transmission system. Specifically, the remaining requirements provide that a transmission vegetation plan be maintained, implemented and regularly reviewed whereby utilities must perform the requisite vegetation clearance work in order to prevent any sustained outages on the bulk power system. A sustained outage due to vegetation is a known, measurable event to which a penalty sanction will be invoked and therefore provides the required impetus for adherence to standard FAC-003-2.Requirement R4 and the associated measure M4 should therefore be removed from the proposed standard

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		language.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Western Area Power Administration, Rocky Mountain Region	Disagree	As discussed in the Technical Reference document and question #11 above, the CCZ is a complicated theoretical envelope surrounding all rated operating positions of the conductor. Its dynamic shape is constantly changing and is contingent upon location within the span. Calculation of the size and shape of CCZ is based, in part, upon the design parameters of the transmission facility. However, as-built or long term maintenance conditions can often diverge from the original design requirements over time. Ground elevations can also change as a result of man made or natural causes from the original design elevations recorded on plan and profile engineering drawings. Consequently, accurate field measurement of the as-built CCZ is extremely problematic and strategies that utilize the calculation of allowable right-of-way tree heights can be hindered by unrecorded deviations from the original design criteria. Allowable tree height strategies also become increasingly more difficult and impractical with increasing extremes in terrain. While the CCZ is a very important concept for an effective vegetation management program it is far to theoretical, dynamic, and impractical to field measure for use as a clear and precise boundary for regulatory purposes. As such, R4 as written should be deleted from the Standards. Further, the requirement to provide evidence of something that has not occurred (no vegetation encroachments of the CCZ) is also impractical. General industry interpretation of R1.2.2 in version 1 of the Standards is that the specific Clearance 2 distance is the precise boundary that is not to be encroached verses the broader area that is ultimately mapped out as the conductor moves through "all rated electrical operating conditions". Only the Clearance 2 distance value is a clear, precise number that can be accurately observed and measured in the field. If there is a persistence to retain the CCZ concept as a requirement within the Standards, the second bullet option above regarding the initiation of the imminent threat process upon discovery of a possible encroachment is the preferred option. Since a potential encroachment into the CCZ is not a violation under this option, exact determination of the CCZ boundary is no longer as essential. Rather, the focus is on triggering mitigation to vegetation problems to prevent outages. However, as with question #11 above, there is still no practical way to determine for regulatory purposes those "potential encroachment" situations that legitimately require initiation of the imminent threat process from those "potential encroachment" situations that do not. Under this option the utility is really motivated to initiate the imminent threat process to avoid an impending outage. As such, the occurrence of an outage becomes the only clear, precise and observable means to determine a Standards violation. A proposed alternative to ensure a level of reliability equal to or better than FAC-003-1 is to retain the Clearance 2 requirement (without the imprecise "all rated electrical operating conditions" language) in combination with the sustained outage requirements of R5, R6 and R7. If an additional margin of safety is determined to be required, industry performance can be adjusted to become more proactive by increasing the minimum Clearance 2 distance to a value greater than the proposed version 2 Gallet equation (table 1) values. Thinking in terms of the

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		CCZ concept, it is obvious that a larger Clearance 2 value translates into a larger CCZ envelope. A larger CCZ envelope in turn triggers mitigation for possible CCZ encroachments sooner.
Response: The SDT thanks you for your comments and proposed alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Progress Energy Carolinas	Disagree	The definition of Critical Clearance Zone includes too many academic and theoretical elements. It is impossible to provide evidence that vegetation did not encroach into the Critical Clearance Zone during TVMP cycles. Furthermore, the operations staff performing periodic ground and aerial inspections would need to determine the CCZ for each foot of transmission line to assure compliance with the standard as it is currently written. The CCZ concept can neither be implemented or enforced as written. The CCZ refers to Ratings which is defined in the Glossary of Terms as "The operational limits of a transmission system element under a set of specified conditions." This definition is too broad to be a consistently enforceable term from one utility or region to the next. As it is currently written, no exemption exists for vegetation falling from outside the Active Transmission Line Right of Way into, or lodging in, the theoretical CCZ.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Southern California Edison Company	Disagree	Q15: SCE does not agree that proposed R4 was written in the most effective way because it establishes a zero tolerance enforcement policy. SCE agrees that a CCZ incursion should be addressed promptly, but we do not agree that a CCZ incursion is equivalent to a vegetation-to-line contact, or that a CCZ incursion represents an imminent threat of flash-over. As written, proposed R4 would require Transmission Owners to prove that a Critical Clearance Zone incursion has not occurred. Short of a daily ground or aerial inspection of every applicable transmission line, it is clearly impossible for a Transmission Owner to monitor their active Right of Way on a 24/7/365 basis to ensure a CCZ incursion will not or has not occurred. Bearing in mind that even the most robust of Transmission VM programs may occasionally identify an anomalous condition (in or outside the active ROW) that left untreated could lead to a flash-over or vegetation-to-line contact, the identification of such conditions typically occur during scheduled aerial or ground patrols and addressed timely. Of the two alternatives offered, SCE finds the first option (second bullet item) to be the most palatable. However, even that option leaves significant doubt as to practical enforcement, because a Transmission Owner could still be found in violation of two separate requirements (R4 and R5, R4 and R6 or R4 and R7) should a vegetation-to-line contact (resulting in a sustained outage) occur. This situation amounts to regulatory double jeopardy. SCE believes that by any reasonable legal or regulatory measure, requiring a Transmission Owner to prove that a CCZ incursion did not

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		occur is impractical and virtually impossible to enforce in a fair and impartial manner. Further, SCE believes that proposed R4 and corresponding M4 detracts from the purported goal of FAC-003-2 and should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
SERC OC Standards Review Group	Disagree	The requirement, as written, compels the Transmission Operator to allocate precious resources to ensuring that a vegetation encroachment NEVER will occur on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R4, if retained, should begin with "Subject to its legal rights," and insert the word "vegetation" between prevent and encroachment. Vegetation, which falls through the Critical Clearance Zone or falls to lodge within the Critical Clearance Zone, should not be included as violations of the Critical Clearance Zone. The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. The SERC OCSRG believes the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The SDT, for clarity, did add the phrase "of Vegetation" as requested.		
Western Utility Arborists		The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. To provide evidence demonstrating there were no vegetation encroachments into the CCZ would be an extremely onerous task and an expensive requirement for the Utilities. The Western Utilities strongly supports the alternative to R4 as recommended in the

Organization	Agree?	Question 15 Comment
		Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, the Western Utilities recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Florida Power & Light	Disagree	NERC standards require the Transmission Owner certify annually that they are in compliance to the standard for the entire year. Since there is no way that a Transmission Owner could monitor every span of line every minute of every day, Requirement R4 cannot be certified. A Transmission owner can only certify that at the time inspected the system met the specification in the standard and that implementation of its Transmission Vegetation Management Plan maintains these specifications. As stated earlier, the Critical Clearance Zone is difficult to accurately identify in the field and without an outage it would be difficult for an auditing body to find and validate. Requirements R4-R7 are reactive in nature. They are violations after the event has occurred or when the tree - wire relationships are so close that emergency action is the only recourse for the Transmission Owner. The standard needs to drive the Transmission Owner to identify and remove trees threatening the system in a proactive fashion. A Transmission Owner should never be in violation for timely action to remove a threat to the system.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Santee Cooper	Disagree	Recommend replacing the word "prevent" in R4 to "monitor". The first alternative that requires immediate removal of vegetation or immediate implementation of the imminent threat procedure would be a Requirement that could be measured. In addition, if an encroachment is found it needs to be eliminated and the first alternative specifies immediate removal. If R4 is left as written, how can you provide evidence that there has been no encroachments within the Critical Clearance Zone.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

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Southern Company	Disagree	The Critical Clearance Zone is a concept that adequately describes the salient functionality a Transmission Owner must consider when determining acceptable clearances. However, the practicality of a requirement that forbids even one encroachment in the Critical Clearance Zone presents a problem for not only the field personnel doing the vegetation work, but also the Regional Entity that must enforce the requirement. This zone changes not only from one span to another, it also changes at each location along each span. The reality is that the difference in encroaching into the zone and not encroaching into the zone is a matter of a fractional inch. In order to prove non-compliance or to defend compliance at a particular site, all vegetation work would have to be postponed for survey accuracy equipment and appropriately trained personnel to be brought to the site, measurements and calculation to be made and consequently a determination rendered. This hardly seems worthwhile when the vegetation could simply be cut, the threat removed and the vegetation work could continue on down the transmission line. As stated in a previous comment, there could be many examples given of encroachments into this theoretical zone that would neither threaten the transmission line conductor nor cause a reduction in the capacity of the transmission line. This concept would be better suited to be a “trigger point” that, if found, would be incentive for the Transmission Owner to either take immediate action or ensure future activities are appropriately scheduled and implemented. This action may be as urgent as implementation of the immediate threat procedure or as non-urgent as making sure that the upcoming maintenance on that line is scheduled appropriately. If a sustained outage occurs due to an encroachment, the outage should be the compliance measure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
E.ON U.S.	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it remains theoretical in nature and impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. In addition, this complexity leads to questions about the ability to audit this requirement. These complexities introduce reliability and audit issues when encroachments into this conceptual area are defined as violations. We believe the Sustained Outage, as defined by other measures in this standard, should be the non-compliance measure. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		

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Bonneville Power Administration	Disagree	R4 states that the Transmission Owner is in violation of the Standard if the Critical Clearance Zone is encroached upon. The CCZ, as defined by the Standard, changes along the transmission line from the insulator to mid-span, depending on loading, actual operating temperature, wind and ice loading, maximum design rating and operating load, etc. Also, the tandem, Measure M4, requires that the Transmission Owner has evidence demonstrating that there has been no vegetation encoachments in the CCZ along its transmission system. In order to meet the letter of the Standard, that is to provide evidence that no encroachments in the CCZ have occurred under all manner of these fluid environmental and operating conditions, the Transmission Owner would have to employ the highest level of modeling technology available, which would seem to be LiDAR technology. The standard should not be written in such a manner so that it requires, by all intent and purpose, a Transmission Owner to acquire a particular technology. BPA recommends that the Alternative represented by "the second bullet" above, be used rather than R4 in its present state, or that R.4. be simply dropped and R1.4 modified to state that the imminent threat procedures include immediate removal of encroachments into the Critical Clearance Zone. Also, the term "immediate" implies instantaneous response. The use of another term is recommended, such as "as immediate as human health and safety considerations allow, in order to prevent the possibility of flashover".
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Public Service Electric and Gas Company	Disagree	An additional clarifying exception in the footnotes to R4 consisting of a tree that is located off of the transmission owner's right of way falling into the CCZ should be added to the encroachment exceptions. Transmission owners should not be found in violation of the standard for falling vegetation located off of the TO's property.
Response: The SDT thanks you for your comments. The SDT has added the exception you requested. Note that the exception applies to any falling vegetation regardless of its location. **3. Brief encroachment into the Minimum Vegetation Clearance Distances listed in Attachment 1 resulting from falling vegetation.**		
FirstEnergy	Disagree	Providing evidence to prove that there were no encroachments of the CCZ is difficult at best. An occurrence of an encroachment does not necessarily translate to an outage. The CCZ is dynamic and difficult to measure exactly from span to span and day to day and is dependent on environmental and line conditions. The costs to comply with this requirement as written are difficult to justify considering that reliability may not be improved at all. FirstEnergy believes that the first alternative above should be used and is a more logical approach from both a reliability and compliance standpoint. Furthermore, since the first alternative is already covered by the currently proposed wording of R2, the only changes needed to the standard are to remove the proposed R4 and M4 and re-number the requirements.

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Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
MRO NERC Standards Review Subcommittee	Disagree	The MRO believes R4 should be eliminated as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Midwest ISO Stakeholders Standards Collaborators	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The proposed standard revision specifies the MVCD as a starting point and TO's may apply multiples at their own discretion in order to achieve their TVMP objectives and adhere to applicable safety standards.		
SERC Compliance Staff	Disagree	The concept of the Critical Clearance Zone is useful as a mental model to visualize required vegetation

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		management work. While this is a good conceptual tool to drive consistent terminology and proper vegetation management practices, it is impractical to measure on a span by span basis. The complexity of determining an encroachment into the Critical Clearance Zone is overly burdensome due to the need for survey accuracy measurements and engineering evaluations. While it may be a technically sound approach to designate the clearance zone to be tied to the conductor movement envelope as found in the NESC, this results in a banana-shaped zone that is difficult to substantiate in the field by entity and compliance personnel. We suggest that the Critical Clearance Zone concept be kept in the technical white paper and that all references to the Critical Clearance Zone be removed from the body of the standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
ITC HOLDINGS	Disagree	First, it's impossible to determine that no encroachments into the CCZ have occurred at any time and determination of the CCZ from the field perspective is problematic. The standard is ambiguous and it seems like clear cutting is the underlining message that is wanted. Determining an encroachment into the CCZ is problematic due to the need for survey accuracy measurements and engineering evaluations. This will also lead to questions about the ability to audit this requirement. The CCZ changes in size and shapes continuously in each and every span and will be difficult to monitor. This would require field personnel to spend numerous hours estimating and attempting to measure potential encroachments of the CCZ. The way R4 is currently written the Transmission Owners would be required to self-certify compliance with R4, and which we don't think this is possible. This will lead to audit issues with more scrutinizing and potentially more penalties or fines. It is important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and not to precisely measure clearance zones. Alternative 2 would be the most logical choice, depending on easement/legal rights, with changes that would eliminate any reference to a trigger point into the encroachment zone of the CCZ to; measuring encroachment to a fix distance (Gallet tables) observed by field personnel
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Tennessee Valley Authority	Disagree	TVA recommends that R4 be removed from this standard. Since this is a "zero tolerance" standard with substantial penalties for controllable vegetation related outages there is an overwhelming incentive for the Transmission Owner to proactively perform inspections, preventative maintenance, inpections and corrective maintenance to prevent potential outages. As such, R4 does not add any value to improving reliability while causing numerous

Organization	Agree?	Question 15 Comment
		unresolvable problems.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Exelon	Disagree	The first bullet is unworkable in the real world. It will be virtually impossible to prove that "no encroachments of the CCZ have occurred anywhere at any time during the compliance period". The effort to do this will not enhance reliability. In fact, in may harm reliability by requiring unnecessary investments and O&M expenditures that could be better spent on real reliability enhancements. Exelon agrees, subject to the development of a workable definition of the CCZ, that the second bullet is the preferred approach.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Central Maine Power Company	Disagree	Central Maine Power Company suggests the second alternative to R4 as recommended above, which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the critical clearance zone, thus preventing an outage. This alternative is similar to R2, therefore R4 may not be required.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
American Electric Power (AEP)	Disagree	AEP disagrees with the proposed requirement that violations be automatically declared if the CCZ is encroached. Instead, AEP would support a standard utilizing the first alternative proffered in these comment questions. While the CCZ is an interesting theoretical concept, it is not realistically feasible in the field to implement a concept that depends on accurate measurements and calculations. Further, the proposed requirement offends common notions of reliable maintenance methods, because it demands that forestry crews stop work if they see a potential encroachment and that surveyors and engineers be brought in to take detailed measurements and perform complex calculations to determine whether an encroachment has in fact occurred. The need for a reliable transmission grid would be much better served by a standard utilizing the first alternative, in which no violation occurs in the event of an encroachment as long as the TO implements its imminent threat procedure and removes the vegetation. While seemingly technically appealing, the CCZ concept is fraught with implementation difficulties. It should not be used as a Pass/Fail zero-tolerance decision point to determine whether a violation has occurred.

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		After all, a zero-defect condition has not been achieved in many other aspects of electric utility operation. For instance, the utility industry attempts every year to conduct its business without any workplace deaths, yet deaths occur every year. Many millions of dollars are spent by North American utilities to promote safety programs and safe work procedures, but some work-related vehicle accidents and personal injuries still occur. Also, utilities aggressively investigate electric switching errors and have instituted rigorous dispatcher-training programs, but a few switching errors still occur. For an industry in which billions of stems of vegetation must be managed, even a high six-sigma level of quality would still result in a few cases annually of imperfectly managed vegetation. It is unreasonable to expect zero-tolerance perfection with the CCZ concept. Also, with the way R4 is worded, a tree falling from outside the right of way would result in a violation if it passed through the CCZ, whether it resulted in an outage or not. It is not appropriate to place a burden on the TO for such circumstances outside the TO's control. As R4 is written, it appears that there is no way that a TO could certify at the end of the year that it has maintained a CCZ free of encroachments, even if no outages occurred. AEP believes a more effective and reliability-centered approach would be one where TOs are expected to implement their imminent threat procedure if vegetation is encroaching upon the Gallet equation distance. If TOs act accordingly and remove the vegetation without incurring an outage, then they would not be in violation. However, if the TOs knew of vegetation encroaching upon the Gallet equation distance but failed to implement their imminent threat process, they would be in violation and be obliged to report the event.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Platte River Power Authority	Disagree	This requirement should be removed completely. It is too stringent and it is impossible to prove compliance through documentation. Encroachemnt of Clearance 2 (or CCZ) should be addressed in the imminent threat procedure.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
City of Tallahassee	Disagree	VEHEMENTLY DISAGREE! The purpose of the standard is to prevent vegetation related outages. A violation should occur if an outage occurs. As written, R4 and M4 would be impossible to prove or disprove. It is not like we can get up there with a tape measure and measure it. R2 requires action if the CCZ is "approached". This is undefined and subject to a myriad of interpretations. Evidence is hard enough to obtain to the satisfaction of the Compliance Monitor. To require sufficient evidence to prove that something didn't occur is a tremendous burden and is not a wise expenditure of vegetation management dollars. Let us spend the money on trimming and not on paperwork. As an alternative replace "encroachment within the Critical Clearance Zone" with "vegetation caused

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		outages". This would allow the same exceptions and is much easier to prove or disprove with a breaker operation. Although this would result in the cause of every breaker operation being tracked, it is a tangible evidence requirement and leaves very little room for interpretation. The levels of fines have already shown that vegetation management is a serious standard and we had better comply.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Northern Indiana Public Service Company	Disagree	It will be impossible for a T.O. to provide "evidence" that no encroachments of the C.C.Z. occurred at any time during the year. This approach will be a compliance nightmare and is unworkable. How does one prove this never happens? You can't monitor every span of every line at all times. Obviously, whenever a T.O. has a preventable outage, that should be a violation. To address the issue of preventing outages before they occur and penalizing T.O.'s who don't take proper steps to prevent them, I prefer the approach of immediate removal of threatening vegetation that encroaches within a "threat trigger/action threshold" clearance distance per the T.O.'s formal imminent threat procedure. This "threat trigger/action threshold" clearance would be established by the T.O. and be a specific requirement under a revised FAC-003.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Tampa Electric Company	Disagree	This is a good start. The Critical Clearance Zone (CCZ) is a very real and practical concept; however, it is not transferable to field conditions. This could result in a "fill in the blank" standard relative to what the Critical Clearance Zone will be in terms of distance. As I read this, it will be a sliding scale from insulator to mid span and back for each designated line voltage. The max wind speed to be used and other assumptions behind the determination of this zone may be as involved a Gallet's formula. This will lead to complications during operational inspection and verification of these clearances.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Orange and Rockland Utilities Inc.	Disagree	We believe that R4 is not the most effective way to achieve the purpose of the Standard. As previously stated the CCZ and encroachments of it are generally not possible to identify in the field without taking precise measurements. The CCZ changes in size and shape continuously throughout each and every span. In many

Organization	Agree?	Question 15 Comment
		cases the CCZ can be very large, and the position of the conductor with respect to encroaching vegetation within the CCZ can be relatively far apart. Such cases would typically not be identified as encroachments of the CCZ by visual inspections. Only those instances where the vegetation is significantly overgrown would be readily identifiable. R4, as written presents a problem in terms of compliance, certification of compliance, and auditing because precise measurements of every span are impractical and costly to perform. Certification of compliance would require field personnel to spend valuable time estimating and attempting to measure potential encroachments of the CCZ. R4 does not provide incentive for Transmission Owners to deploy modern technology that is better able to identify encroachments of the CCZ with a reasonable amount of accuracy, such as ALS and LIDAR which are described in the response to Question 11. In fact R4 might provide an incentive not to utilize this technology because Transmission Owners who identify encroachments using ALS which would otherwise not have been identified would be in violation of R4. Transmission Owners that choose to be less proactive often would not identify such encroachments and would be at less risk of violating R4. The effect could be less frequent use of ALS and other technology that may emerge. This would result in fewer problems being identified, a small percentage of which may not be discovered until they result in a line trip. We believe that the best way to achieve the purpose of this Standard is to encourage proactive behavior which prevents vegetation-related outages throughout the entire industry. R4 does not achieve this in the most effective way. We recommend the following: Eliminate encroachment of the CCZ as a violation of R4. Require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where vegetation has grown within a specific distance as described in the response to Question 11 regarding R2. This would essentially combine R2 and R4.Require Transmission Owners to report to the Regional Entity any instances where the imminent threat process was implemented due to a vegetation-related clearance encroachment. This would add a reporting requirement for Transmission Owners. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for vegetation-related clearance encroachments. The metrics should be established in the Standard based upon 1000 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. Modify R5, R6, and R7 to include preventing momentary outages as well as Sustained Outages. We believe that this concept would result in a more rigorous standard because of the additional requirements, but would focus the industry's attention in a more effective fashion. We believe it would result in fewer vegetation-related interruptions and a higher level of reliability soon after implementation, and would therefore best support the purpose of the Standard.

Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.

The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation, and chose to address this issue with the language in R4.

Organization	Agree?	Question 15 Comment
American Transmission Company	Disagree	While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and ATC does not think there is a practical way to do that. Clearly, the approach of assessing violations for CCZ encroachment is unworkable. ATC believes that R4 should be deleted.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Xcel Energy	Disagree	The way this requirement is written may require a utility to prove a negative. In other words, prove that we did not have trees encroaching into the CCZ at any time. This is impossible to prove. We propose the following language: ?The TO shall not have a encroachment within the CCZ which was not dealt with by utilizing the imminent threat procedure before experiencing a Sustained Outage, with the following exceptions 1) Encroachment of the CCZ that result for natural disasters 2) Encroachment of the CCZ that result from human or animal activity."
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Ameren	Disagree	The second bulleted alternative above is the best approach, but it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is defined in the Plan. This would allow Transmission Owners to define for field personnel a CCZ that accomplishes some multiple of the Gallet distances referenced in Table I" but is easy to determine and apply. We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4, and we don't think there's any way to do that. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same

Organization	Agree?	Question 15 Comment
		inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Nebraska Public Power District	Disagree	NPPD disagree with an encroachment being a violation. A lot of time would need to be spent to determine if an encroachment occurred and in a self regulating environment, reporting would be minimal if any. The Transmission Owner would be in violation for any non natural event. Even a tree falling into the ROW passing through CCZ would be in violation of R4. Difficult at best to enforce. We need to spend time keeping the ROW cleared and less time inspecting for possible encroachments.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Long Island power Authority	Disagree	The Standard is about preventing outages and having an effective program. An effective program should allow for the identification of a threat and the removal of the threat prior to a vegetation caused outage. I prefer alternative 2. If a vegetation caused outage should occur or if the Regional Entity determines a violation occurred based on a compliance investigation then the entity is in violation of this requirement.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	The wording appears too strong. Who can predict the unforeseen circumstances that inevitably arise. If the standards require the reporting of encroachments, the ensuing report can help determine if the Transmission Owner did everything reasonable to avoid the problem. It seems like the standard should be written to require the Transmission Owner to do everything reasonable to avoid the problem. A judgment call would still be needed to evaluate the performance.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

Organization	Agree?	Question 15 Comment
Manitoba Hydro	Disagree	Manitoba Hydro asserts that the reliability of the system is measured by outage, not by the possibility of an outage, and therefore if the overall vegetation management system (plan-patrol-discover-mitigate) is effective in preventing an outage, then the reliability of the system has been maintained, and the intent of the reliability standard achieved. Therefore, we propose that the second bullet above is the preferred alternative, and that R2 and R4 be combined as the violation of R4 would then imply a violation of R2.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Consumers Energy Company	Disagree	The CCZ does not provide adequate clearance and the imminent threat procedure if successfully implemented only works IF YOU KNOW ABOUT THE VEGETATION THAT THREATENS THE CCZ which cannot be ensured with yearly inspections. Consumers Energy believes that the Clearance 2 distances in FAC-003-1 provide more reliability than the CCZ proposed in this draft or any of the alternatives disused above.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Pacific Gas & Electric Co.	Disagree	PG&E believes a "minimum clearance distance" or "do not encroach zone" is a critical element of this standard and necessary to achieve the stated purpose of preventing vegetation caused outages. Preventing vegetation encroachments will prevent outages. However, PG&E disagrees with using the CCZ as a minimum clearance requirement because it is ambiguous and subject to wide variations and interpretation. CCZ is a good concept to aid in understanding movement of conductors but is a theoretical calculation and would be very difficult if not impossible to enforce. PG&E suggests using a clearly defined distance such as Gallet equation plus a safety margin to assure there is no chance of spark over. Two times Gallet would be a reasonable clearance requirement to assure a spark over does not occur and eliminate the ambiguity of the CCZ as the "do not encroach zone".
Response: The SDT thanks you for your comments. The SDT discussed the Gallet plus alternative suggested by PG&E. Due to the tremendous variation of design standards, the team decided that the decision as to how much a margin for error to use belonged to the individual TO. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The threat of a violation is believed sufficient to motivate a Transmission Owner to maintain a larger clearance.		

Organization	Agree?	Question 15 Comment
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. NV Energy strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
San Diego Gas & Electric	Disagree	The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone (CCZ) occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner have evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually to prove that trees have not encroached upon the CCZ. This would be an extremely oerous and expensive requirement for utilities. We strongly support the alternative to R4 as recommended in the Comment Form, which is wto require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2. Therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Hydro One Networks Inc.	Disagree	A statement is needed that this requirement applies to the active right of way. Outside of the active right of way there is no guarantee that this can be achieved. As noted in the question above, it may be very difficult with the

Organization	Agree?	Question 15 Comment
		first alternative to provide adequate evidence that no encroachment had occurred over the compliance period, as the situation is very difficult to assess along each span to the accuracies (1/100 of a foot) spelled out for the CCZ. It may be more meaningful that the Transmission Owners be able to demonstrate processes, methodologies and actions that can support that vegetation has not entered the CCZ. Another alternative for R4 could then be: Each Transmission Owner shall demonstrate that adequate actions and processes are in place to prevent vegetation from entering the CCZ. The effectiveness of the process can then be evaluated based on methods used for field assessment and performance, i.e., outages and imminent threat reporting. It appears that the second alternative noted above can be combined with R2. It is not clear why there needs to be a separate requirement. Hydro One is not in favour of alternative 3, as this would create added administration with a situation that will be difficult to prove to the accuracy required. LIDAR may be the only means available to provide evidence of a quality needed to produce meaningful statistics, and in many cases this may not be the most efficient use of the limited funding that is available.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Edison Electric Institute	Disagree	Encroachment without a Sustained Outage should not be construed as a violation. The proposed R4 requirement should be removed. EEI strongly believes that this requirement, if approved, is unenforceable. The alternative, to require implementation of the imminent threat procedure, should be considered as a practical approach. In particular, this concern applies to a requirement to prove that no encroachments have existed. This will require extensive work by field personnel, who will be required to make subjective judgments. In addition, determining actual clearance zones in the field would require a span-by-span analysis to be conducted with the rigor of survey level measurements. Calculations made to determine the clearance zones are based on undefined terms and subject to wide variation. Enforcement authorities will be required to make interpretations. EEI believes that the costs of conducting such work will not deliver sufficient benefit to warrant the requirement. Ultimately, there is no basis for determining whether the theoretical clearance zones included in the proposed standard will increase, or even maintain, an adequate level of reliability as provided by the existing standard.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Consolidated Edison Company of New York (CECONY)	Disagree	CECONY disagrees with R4 as currently written. As mentioned in the response to Question 15, performing a field measurement of the CCZ and a field measurement of the vegetation encroaching into the CCZ are complicated, time-consuming efforts. As the CCZ changes along the conductor, so too may the Active ROW dimensions, the vegetation clearances at multiple points, and elevation levels to name a few. Certifying compliance that no

Organization	Agree?	Question 15 Comment
		encroachments have occurred would be very difficult for auditors and field inspectors. Modern laser technology would have to be deployed to take these measurements and CECONY is concerned that, if an encroachment of the CCZ constitutes a violation, utilities would not consider investing in this technology knowing that multiple violations could potentially be found within a single span. Enhanced reliability is achieved when utilities invest in the best available technology and perform proactive inspections on their systems but, as written, R4 would not effectively motivate a utility to follow through with these initiatives. We recommend that the term 'momentary outage' or the phrase 'all outages' be used in R5, R6, and R7 instead of 'Sustained Outages' to avoid confusion throughout the industry. Momentary outages identify a potential failure of the utility's vegetation management program and stating it directly in the Standard clearly sends the message to utilities that all vegetation outages are unacceptable. In summary, we do not agree that encroachments are violations but we do recommend that when a utility identifies vegetation-related imminent threats and takes immediate action, they report this to their Reliability Coordinator. The Reliability Coordinator (RC) could then identify the utilities that have had multiple issues or have exceeded acceptable pre-established reporting limits which, in turn, would help the RC prioritize auditing efforts. This, in our opinion, would enhance reliability more effectively.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. **The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of “momentary outages” are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.**		
Arizona Public Service Company	Disagree	APS agrees with alternative one. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the CCZ occurs at any time. However, the CCZ changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. Further, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the CCZ. These requirements may result in having to LIDAR the lines annually, to prove that trees have not encroached upon the CCZ. This would be an extremely onerous and expensive requirement for utilities. APS strongly supports the alternative to R4 as recommended in the Comment Form (#15), which is to require immediate removal of the vegetation or immediate implementation of the imminent threat procedure upon discovery of a possible encroachment of the CCZ, thereby proactively preventing an outage. This means a violation would occur only if the imminent threat process is not successfully implemented. This alternative is essentially the same as R2.

Organization	Agree?	Question 15 Comment
		Therefore, APS recommends removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Baltimore Gas & Electric Company	Disagree	One concern with the proposed wording is that the verbiage seems to provide a loophole that will count any fallen tree, or tree with the potential to fall from inside or outside of the R/W (that doesn't meet the criteria in footnotes 4 & 5) that passes or could pass through the CCZ, and that may or may not cause an outage, would qualify as a violation in the std. There is no other language that I can detect in the std. that counters this point. Determination of whether or not a fallen tree, or tree with the potential to fall would qualify would be predicated upon height measurements of the fallen or standing tree(s) relative to the CCZ at max. engineered sag. An alternative wording suggestion is: "Each Transmission Owner shall prevent encroachment within the Critical Clearance Zone of it's applicable lines associated with trees that meet the criteria for grow-ins from on or off the Active right-of-way. Fall-ins from inside or outside of the active right-of-way are not applicable to this sub-requirement." If the occurrence is a violation, reporting of the incident will be an ethical issue and rely on the honesty of the inspector or whomever finds the problem. If it's not a violation, it will be more likely that the incident will be reported and can be treated as "Near Miss' reports are with respect to safety incidents - they provide valuable input to help forestall future more serious incidents. Consequently, I recommend that no violation occur as long as the 'Imminent Threat Procedure' is implemented. Further, if there is no violation associated with Imminent Threat Procedure implementation, I would suggest that falling or standing trees originating from within the active right-of-way that encroached or could encroach in the CCZ be added to the requirement to enhance the 'Near Miss' data pool.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Duke Energy Corporation	Disagree	The second bulleted alternative above is the best approach, but Duke believes it should be improved by changing the imminent threat trigger from "encroachment of the CCZ" to "encroachment within some observed, field distance that is a multiple of the Gallet distances referenced in Table I". We have recommended changes to accomplish this in Requirement R2 (see our response to Question #11 above), and R4 should simply be deleted. While the CCZ is valuable to understanding the movement of conductors, it cannot be readily applied in the field. This field application challenge is noted in the Technical Reference Document (pages 29 & 30).The way R4 is currently stated, the Transmission Owner would be in violation of R4 for any CCZ encroachment not due to natural disasters or human or animal activity. This would include a tree falling from outside the right of way corridor that passes through the theoretical CCZ. Furthermore, Transmission Owners would be required to self-certify compliance with R4. The technological requirements for accurately certifying compliance would be impossible to

Organization	Agree?	Question 15 Comment
		administer. Clearly the approach of assessing violations for CCZ encroachment is unworkable. Likewise, the third alternative listed above is untenable. The tiered approach could have a mitigating effect on violations, but it would require the same inspection effort and postponement of vegetation management that makes the first alternative unworkable. Both the first and third alternatives would require very significant additional expenditures for surveys and documentation in an impossible attempt to certify compliance - money that would be better spent controlling vegetation.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
CenterPoint Energy	Disagree	It is not reasonable to expect Transmission Owners to devote resources, both human and financial, to prove that vegetation never encroached into the Critical Clearance Zone, anytime-anywhere. R4 and M4 should be deleted.R2 and M2 are sufficient in ensuring a level of reliability equal to or better than FAC-003-1 with some minor wording changes to adopt similar wording of the alternative to R4 that was considered by the drafting team that includes "immediate implementation of the imminent threat procedure" for imminent threats of a vegetation related Sustained Outage in lieu of a nebulous "encroachment of the Critical Clearance Zone". According to the Technical Reference, it is "nearly impossible to field correlate and accurately 'superimpose' the Critical Clearance Zone around the conductor". It not likely that the Transmission Owner will know when the Critical Clearance Zone is approached through field observation. The previous Clearance 2 provided for a specific radial clearance from the conductor that was much easier to observe. (See comments to Q3 above.)
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Entergy Services	Disagree	1. Entergy believes that outages caused by vegetation are the most reasonable and objective measures for a violation which is not consistent with the proposed R4. See additional comments in section 16 related to R5, 6, and 7. 2. If R4 remains, Entergy proposes that the most reasonable approach to this requirement is a variation of the second bulleted option. This variation would include wording clarifying that only known encroachments of the Critical Clearance Zone would be considered violations. Entergy is willing to include failures to enact the imminent threat process (which is really a violation of R2) and also known vegetation inside the Critical Clearance Zone. This variation should continue to include the exceptions for natural disaster and human activities. 3. Determining objective, quantifiable encroachments into the Critical Clearance Zone is very challenging in field operations because such determination may require a degree of accuracy only obtainable using survey equipment

Organization	Agree?	Question 15 Comment
		or other sophisticated, costly measuring devices. 4. Entergy is concerned about the challenges of uniform audit ability due to noted uncertainties and the statement of absolute criteria that have to be shown in the negative. If the first bullet option is approved for R4, Entergy suggests the sentence “Evidence will be required to prove that no encroachments of the Critical Clearance Zone have occurred anywhere at the any time during the annual compliance period” be deleted. It is very difficult in regulatory terms to attest that no vegetation has ever crossed the Critical Clearance Zone during the time period being reviewed given the wide range of potential conditions that may not have been detected or even been detectable unless the conditions afforded direct observation. Too many assumptions would have to be made for an entity to self certify to this requirement. If R4 is implemented as stated, those assumptions need to be stated and clarified. 5. If any version of R4 is approved, Entergy suggests that the standard include an exception for trees falling from off the right of way and encroaching the Critical Clearance Zone. For example, a tree that falls from off the right of way. During the fall towards the conductor, the tree could possibly break the Critical Clearance Zone without causing an outage or even a threat of an outage yet still be a violation of the proposed standard. 6. If the second bulleted item is approved, it should be altered to read “a violation would have occurred only if no vegetation imminent threat process was initiated.” 7. Entergy does not feel the third bulleted item is adequately defined to use as a requirement in the standard at this time. 8. Conditions for blow-out, in the development of the Critical Clearance Zone, need to be defined in the standard. Their inclusions, in the white paper only, are not appropriate, as well.
Response: The SDT thanks you for your comments and suggested alternatives. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time. The SDT addressed your item 5 in subpart 3 in R4. This exception would apply to any falling vegetation outside the right of way or inside the right of way.		
Pepco Holdings, Inc	Disagree	As discussed in our response to Q11, the concept of encroachment into the Critical Clearance Zone is flawed. It is enforceable almost exclusively through self reports. R5, R6 and R7 provide all incentives for the TO to follow its inspection and maintenance plans, and R2, if properly written to remove references to the Critical Clearance Zone provides additional incentives. R4 is not needed and should be deleted. PHI is puzzled where this concept came from. Nowhere in Order 693 is this concept discussed.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon		

Organization	Agree?	Question 15 Comment
substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time. The concept of the CCZ was originally intended to provide an area that could be used to produce a metric for less than "zero tolerance" however that did not materialize.		
JEA	Disagree	As written, demonstration of compliance may not be feasible and would certainly be prohibitively expensive, consuming resources better spent managing vegetation. In general, putting entities in the position of proving something didn't occur is exptremely difficult and burdensome, without really aiding reliability. If the incident was significant, the region would know about it, and investigations can be pursued, if warranted. The first alternative requiring implementation of the imminent threat procedure is a better choice.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Salt River Project	Disagree	Disagree with R4 as it is written. The new requirement in R4 stipulates that the Transmission Owner is in violation if an encroachment of the Critical Clearance Zone occurs at any time. However, the Critical Clearance Zone changes with each foot of the transmission line from the insulator to the mid-span, depending on loading, actual operating temperature, wind loading, ice loading, maximum design rating, maximum operating load, and so on. See additional comments in Comment #18 below. Furthermore, Measure M4 requires that the Transmission Owner has evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone. To provide evidence demonstrating there were no vegetation encroachments into the Critical Clearance Zone would be an extremely onerous task and an expensive requirement for the utilities. We strongly support changing this to the 1st alternative written in Comment #15 "One alternative to R4 required immediate removal of the vegetation or immediate implementation of the immenent threat procedure upon discovery of a possible encroachment of the Critical Clearance Zone, thereby proactively preventing an outage. A violation would have occurred only if the immenent threat process was not successfully implemented." This alternative is essentially the same as R2, therefore, we recommend removing R4 from the standard entirely.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Northeast Utilities	Disagree	First - the determination of the CCZ is highly problematic in the field. Second - it is impossible for any utility to certify that no encroachments have occurred at any time unless a utility has completely removed all potentially interferring vegetation on all areas of their transmission system. If the standard is to clear-cut and maintain a tree free right of way, the standard should say so. To determine if vegetation may have violated the CCZ the inspector

Organization	Agree?	Question 15 Comment
		must know at the time of the inspection the ambient temperature, the wind speed, the loading of the line and the actual distances between the vegetation and conductors. Then, the information must be compared to possible extreme operating levels of the line under all conditions to know if the vegetation may violate the CCZ. As stated - it is improbable that this could accurately be performed in the field as the data changes within each segment of a span's length. The first alternative provides the most effective means of addressing encroachment of the CCZ - having an encroachment is not a violation - knowing there is an encroachment and not correcting the problem would be a violation. Implementing the imminent threat procedure and correcting the problem is a more effective approach. Having a zero tolerance for encroachments of the CCZ under all situations and operating conditions would sub-optimize the use of resources. No actual event may have occurred on the system, yet the utilities will be in violation just for a possible or potential problem that even under extreme operating conditions may not actually occur. It would be best if the violations were limited to "known encroachments" (not "possible encroachments") such as would occur if a line were to trip due to vegetation contact, or if there is evidence of any burns. If no action was taken on known encroachments to correct the problem (such as implementation of the imminent threat procedure) then a violation will have occurred. It is doubtful that any utility will be able to certify that at no time has vegetation encroached into the CCZ. Utilities will have to spend an untold amount of resources to verify that there have not been any encroachments during a compliance period - instead of using these resources more effectively in taking proactive measures to manage and control encroaching vegetation. As written, any encroachment into the CCZ is considered a violation of FAC-003-2 (R4). There are exceptions provided for encroachments due to natural disasters and human or animal activity. There is no exception for encroachments due to the failure of a tree(s) outside of the active transmission line ROW. Based on R4, a trip and reclose of a transmission line (no outage) is a violation even if the tree is outside of the active right-of-way; whereas per R6 and R7, a line outage would not be a violation if the tree was outside of the active right-of-way. As written - this is not clear - there should be exceptions to allow for trees falling into the CCZ (and into the active transmission line right-of-way) from outside the limits of the active transmission line right-of-way. Also - how are violations of the CCZ requirement to be reported - there is no provision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added?
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the “Minimum Vegetation Clearance Distances”, and Transmission Owners are required to prevent encroachment of vegetation into “Minimum Vegetation Clearance Distances” as observed in real time.		
Hydro-Quebec Transenergie (HQT)	Disagree	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". We believe that R4 is not the most effective way to achieve this purpose because it does not provide incentive for Transmission Owners to take advantage of modern technology, such as aerial laser survey (ALS) using Light Detection and Ranging technology (LIDAR), that is capable of accurately identifying vegetation which is approaching the CCZ or has encroached into it. In fact R4 provides an incentive not to utilize this technology because Transmission Owners who identify encroachments would be in

Organization	Agree?	Question 15 Comment
		violation of R4 for each identified encroachment. On the other hand, Transmission Owners who choose to be less proactive often would not identify such encroachments because the CCZ and encroachments of it are generally not easy to determine without taking precise measurements. Unless the line is heavily loaded or the vegetation is significantly overgrown, encroachments of the CCZ would not be readily noticed. In most cases these Transmission Owners would simply remove or cut back incompatible vegetation without taking measurements. The threat to the line would have been eliminated with no encroachment having been identified.R4 presents a dilemma for Transmission Owners that are considering making the significant investment in ALS technology. While the technology would allow them to identify any potential grow-in or fall-in conditions, it would also expose them to the risk of identifying violations of R4, that would otherwise not have been identified. Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), and Time Horizons are not included in this Draft, but after making a significant investment in ALS, Transmission Owners could be faced with significant additional cost in terms of NERC penalties. In addition, even if the penalties were relatively low they would be exposing themselves to violations that less proactive Transmission Owners would not be exposed to. In our view R4 as written would, in some cases, have the opposite effect of what is intended because the business case for using ALS is more difficult to make. This will result in less use of ALS and other emerging technology that is likely to be developed. This would result in fewer problems being identified, a small percentage of which will not be discovered until they result in a line trip. Still we believe that the concept of the CCZ is a good one and recommend that R4 be changed so that Transmission Owners are provided with an incentive to invest in the best technology available in order to ensure the highest level of reliability. The opportunity exists to develop the standard in a manner that encourages the industry to take advantage of new technology and manage vegetation in a very proactive way. We recommend that R4 be changed as follows: Modify R4 to require Transmission Owners to immediately implement the imminent threat process defined in R1.4 when they identify instances where the CCZ is approached or encroached upon. Failure to do so would be a violation of R4. Eliminate encroachment of the CCZ as a violation of R4. This would eliminate R2 and incorporate implementation of the imminent threat process into R4.Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where the imminent threat process was implemented due to an encroachment of the CCZ. This would add a reporting requirement for Transmission Operators. Require Transmission Owners to report to the Regional Entity on a quarterly basis any instances where either a momentary or sustained outage was caused by grow-ins, Active Transmission Line Right of Way blow-ins, or Active Transmission Line Right-of-Way fall-ins. This would add three additional reporting requirements for Transmission Operators. Require Regional Entities to perform additional audits of Transmission Owners that exceed metrics for violations of the CCZ. The metrics would be established in this Standard based upon 100 circuit miles of applicable lines. This would add an additional requirement for Regional Entities. This concept would result in a more rigorous standard than FAC-003-01 because of the additional reporting and auditing requirements. It would drive proactive behavior throughout the industry and provide a significant incentive for Transmisison Owners to invest in new technology such as ALS that is capable of accurately identifying vegetation that has approached or encroached upon the CCZ. We believe that this change would result in the identification of more incipient vegetation-related problems and fewer vegetation-related outages as soon as it was implemented and

Organization	Agree?	Question 15 Comment
		would best support the purpose of the Standard.
Response: The SDT thanks you for your comments and suggestions. The reporting and documenting concept that you suggest has been incorporated in part in R2. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Buckeye Power, Inc.	Disagree	Proving vegetation is not in a clearance zone will be difficult without having third-party verification.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Great River Energy	Disagree	GRE supports the elimination of R4, as vegetation contacts are covered in R5 and R6. A violation should only occur with a vegetation contact. Assessing a violation and fine for a potential reduction in system reliability is not correct. Actual contacts that trip a transmission element have some measurable impact on system reliability even if it is slight. In the event that the SDT chooses not to eliminate R4, GRE would also support the alternative language that is shown under the second bullet.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
WECC	Agree	Yes, R4 as written provides clear guidance to TOs on the minimum radial distance, dependant on line voltage that vegetation is allowed to approach energized conductors. These industry standardized distances will ensure a level of reliability equal to or better than FAC-003-1.
Response: The SDT thanks for your comments. Please see the summary consideration for this question – based on other comments, the SDT made significant revisions to Requirement R4. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
National Grid	Agree	National Grid agrees that there should be no encroachments into the CCZ. However, encroachments in the CCZ should NOT be considered a violation. Violations should only be for sustained transmission outages.
Response: The SDT thanks you for your comments. Significant changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and		

Organization	Agree?	Question 15 Comment
Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		
Northern California Power Agency (NCPA)	Agree	
WECC Reliability Coordination	Agree	
Response: The SDT thanks you for your positive feedback. Most commenters disagreed with R4. Changes to R4 have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ has been replaced with the "Minimum Vegetation Clearance Distances", and Transmission Owners are required to prevent encroachment of vegetation into "Minimum Vegetation Clearance Distances" as observed in real time.		

16. Requirements R5, R6, and R7 define that Sustained Outages due to vegetation growing into, blowing together with, and falling into transmission lines are violations (subject to certain exemptions). Therefore, all such outages must be reported as violations of the standard. Do you agree with this change? If not, please explain.

Summary Consideration: Seventy two percent of the respondents agreed with the changes. Multiple commenters made the following points: Questionable cost benefit, not all lines are equal, complicated and burdensome to know precisely where edge of ROW is, the standard should read minimize outages and not prevent them. The majority of the team did not agree there was sufficient argument to support making changes to the requirements based on the comments.

Several commenters pointed out that debris that has been detached from the tree and blown into the conductor and trees from outside the ROW should be exempt. The team adjusted the standard to accommodate debris and falling from outside the ROW.

Organization	Agree?	Question 16 Comment
Western Utility Arborists		The Western Utilities strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
BCTC		BCTC strongly recommends that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the

Organization	Agree?	Question 16 Comment
		word "minimize" was present in earlier drafts of the document. BCTC is concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW BCTC's operating area covers rugged and remote terrain, and many areas have accessibility issues. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. Further, it is not economically feasible to accurately survey and marked on the ground the absolute width of all ROW in the province. Therefore, we are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. This could lead to an incident where BCTC is charged unreasonably – for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Kansas City Power & Light	Disagree	Exceptions should include flying debris including vegetation.
Response: Thank you for your comment. Your suggestion has been incorporated.		
Associated Electric Cooperative Inc.	Disagree	Requirements 5, 6 and 7, as written, compel the Transmission Owner to allocate precious resources to ensuring a vegetation related outage will NEVER occur on any applicable transmission line, regardless of the line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those which are an IROL or contribute to IROLs should be held to a zero tolerance standard.
Response: Thank you for your comments. FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in accordance with FERC Order 693.		
NPCC	Disagree	NPCC participating members request clarification if violations of R5, R6, and R7 result in outages that must be reported.
Response: The SDT appreciates your response. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.		
SERC OC Standards Review	Disagree	R5, R6 and R7 should begin with "Subject to its legal rights,". The requirements, as written, compel the Transmission Operator to allocate precious resources to ensuring that a vegetation outage NEVER will occur

Organization	Agree?	Question 16 Comment
Group		on any transmission line, regardless of that line's true importance to maintaining electric transmission system reliability. All lines are not created equal; only those that are involved in IROLs should be held to a zero tolerance standard. R5, R6, and R7 ensure that version 2 of the standard has reliability requirements equal to version 1; therefore R4 should be removed.
Response: Thank you for your comments. **The SDT certainly agrees that all actions taken by a Transmission Owner must be within its legal rights, but believes that inclusion of "*Subject to its legal rights*" will tend to unnecessarily limit legitimate actions that a Transmission Owner must take to maintain reliability.** **FERC Order 693 affirmed that the Standard shall apply to all transmission lines operating above 200kV as well as to designated sub-200kV lines. The Standard was prepared in consideration of the directives and recommendations contained in FERC Order 693.**		
Florida Power & Light	Disagree	As currently written, Requirements R5, R6 and R7 demand perfection. The only acceptable number for all 150K miles of affected transmission line in the US is 0. The standard should be achievable and enable proactively addressing potential threats to facilities from vegetation. Even using a Six Sigma level of quality and control, processes can achieve a level of 3.4 defects per million opportunities for defect. Each tree on the ROW represents one of those opportunities. FPL has outlined an alternative proposal in response to Question 18.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT.		
Santee Cooper	Disagree	Recommend removing R7 because current and proposed standards do not require the entire right-of-way or Active Transmission Line Right of Way to be clear of vegetation. In this case, a utility should not be penalized if a tree falls from within the right-of-way or Active Transmission Right-of-Way as long they are meeting all the other standards (e.g., minimum vegetation clearance distances). Since fall-ins from just outside of the right-of-way is currently not a compliance issue, it makes sense that a fall-in from within the right-of-way be treated the same. This is especially true for a utility who has elected to acquire a wider right-of-way than another utility. That utility may have a tree(s) growing just inside the right-of-way but still maintains a better clearance distance between trees and conductors than a utility with a narrower right-of-way and no tree encroachment.
Response: Thank you for your comments. While it is true that there is a negligible difference in risk to the electric system for trees just within or just outside the active right of way, the major difference is that the Transmission Owner generally has the right to manage vegetation within the active right of way. Also, while Transmission Owners employ differing active right-of-way widths, this is essentially uncontrollable by the SDT or by regulators.		

Organization	Agree?	Question 16 Comment
Exelon	Disagree	It appears to Exelon that the requirements of the standard have been written and modified at different times and as a result the document lacks a degree of consistency and coherence. While the Standard mentions encroachment of the CCZ and Sustained Outages as potential violations, it is completely silent on how momentary outages should be addressed. Exelon views the following events as a risk continuum that should be addressed in the Standard and handled as a part of the VRFs and VSLs - encroachment of the air gap distance, momentary outages and Sustained Outages.
Response: Thank you for your comments. The Minimum Vegetation Clearance Distance is the calculated spark-over distance derived from the Gallet equations. Therefore a momentary caused by a tree under the circumstances defined in R4 would by definition be a violation of R4.		
Platte River Power Authority	Disagree	The requirement under R7 should be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	Disagree	I believe that the text for each element should be re-written with the general philosophy that the Transmission Owner shall do everything reasonable to prevent such problems in line with the comment for section 15.Problems should be reported and investigated and a judgment call should be made about whether the Transmission Owner did everything reasonable to avoid the problem.
Response: Thank you for your comments. The purpose of this standard is to improve reliability of the electric transmission system by preventing vegetation-related outages that can lead to cascading by establishing clear and measureable requirements. While the SDT appreciates the value of judgment in the field FERC has indicated that requirements in proposed Standards be equivalent to or more stringent than the same or similar requirements in already approved Standards.		
Consumers Energy Company	Disagree	R5, R6 and R7 should be rewritten as a single requirement for vegetation within the "Active Transmission Line Right of Way" and the exceptions listed. Additionally, a requirement for hazardous trees outside of the "Active

Organization	Agree?	Question 16 Comment
		Transmission Line Right of Way" should be incorporated into this draft and similar exceptions listed for natural disasters, third-party, and animal causes.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors because blow-in and fall-in interruptions do pose a significantly lower risk of causing a cascading blackout event. **Regarding incorporating a requirement to address hazardous trees outside the Active Right-of-Way, Transmission Owners generally have the right to manage vegetation within the Active Transmission Right-of- Way. These rights will not always exist beyond the Active Transmission Right-of-Way.**		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We strongly recommend that the requirement under R7 be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to vegetation falling into a conductor.” We note that the word “minimize” was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine and document precise clearance zones. Such costly effort would not produce any benefit to the reliability of the bulk electric system.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
San Diego Gas & Electric	Disagree	We recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." The word minimize was present in earlier drafts of the document. We are concerned with the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission Right of Way. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		

Organization	Agree?	Question 16 Comment
Hydro One Networks Inc.	Disagree	A further exception would be a sustained outage where the conductor has moved outside of the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind. These would not necessarily be the result of a natural disaster. Also, it is recommended that the requirement for R7 be revised to "Each Transmission Owner shall minimize ("minimize" replacing "prevent") Sustained Outages of applicable lines due to vegetation falling into a conductor".. A fall in is a random occurrence and the likelihood that this would be the cause or contribute to a cascading event is very remote. These types of outages are rare and can be considered similar in nature to an insulator flashover or a hardware failure, which have not been given any association with cascading events. The purpose of the standard is to prevent cascading events and it is suggested that this remain the focus and not introduce other types of outages on a selective basis.
Response: Thank you for your comment. The Critical Clearance Zone (CCZ) has been removed from the standard. **The SDT concurs that fall in events present a lower risk to the system than grow in events. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.**		
Arizona Public Service Company	Disagree	APS strongly recommends that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor." We note that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement for utilities to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where utilities are charged unreasonably ? for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Further, it is not economically feasible for utilities to survey every ROW in the U.S. and Canada to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Entergy Services	Disagree	1. If a version of R4 that states an encroachment to the Critical Clearance Zone is a violation, Entergy disagrees with the need for R5, R6, and R7 because it is redundant to R4. An outage cause by vegetation: a) growing into the line b) blowing into the line and c) falling into the conductor would require the vegetation to break the Critical Clearance Zone. If these requirements stay in the standard, an outage of the above nature would mean the entity violated two requirements, R4 and R5, R6, or R7. 2. Entergy is amenable to keeping

Organization	Agree?	Question 16 Comment
		R5, 6, and 7 if R4 is removed from the standard. 3. If approved, we suggest that R5, 6, and 7 not apply to trees from off the right of way.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. R4 has been drafted to clarify that clearance encroachments are violations of the Standard. Matters of being assessed two violations for a single event are addressed in the NERC compliance sanctions guideline.		
Salt River Project	Disagree	Recommend that the requirement under R7 be changed from "shall prevent sustained outages" to "shall minimize sustained outages due to vegetation falling into a conductor". We understand that the word "minimize" was present in earlier drafts of the document. We are concerned about the requirement to prevent sustained outages from vegetation falling into the conductor from within the active transmission ROW. It is operationally almost impossible to know precisely where the edge of the ROW is in all situations under all conditions. This could lead to an incident where a utility is charged unreasonably - for example, for an outage from a tree that was one foot within the active ROW line. We should not be held liable when reasonable due diligence is practiced. Furthermore, it is not economically feasible for utilities to survey every ROW to determine precise clearance zones.
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. The SDT believes that the Transmission Owner holds responsibility for knowing the location of the edges of its active rights of way and whether a rooted tree is within or outside the active right of way.		
Hydro-Quebec Transenergie (HQT)	Disagree	HQT request clarification if violations of R5, R6, and R7 result in outages that must be reported. A further exception would be a sustained outage where the conductor has moved outside the critical clearance zone. This could occur under conditions of heavy icing, operating outside the line rating or excessive wind.
Response: Thank you for your comments. Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages. **The Critical Clearance Zone (CCZ) is defined by the movement of the conductor between no load and its rating. The Standard does not apply to events which occur outside of the CCZ.**		
Southern California Edison	Agree	Q16: SCE agrees in part with the establishment of R5, R6 and R7, however, we note that the opening of each requirement repeats a slightly altered version of the FAC-002-2 purpose statement. We find such

Organization	Agree?	Question 16 Comment
Company		repetitiveness unnecessary and note that as written, Requirements 5-7 presents a near identical compliance conundrum for Transmission Owners as Requirement 4. Again, Transmission Owners would be required to prove that they did not incur a sustained outage due to a vegetation caused flash-over or vegetation-to-line contact whether it be a grow-in, blow-in or fall-in. Although proving a sustained outage (for cause) did not occur will be difficult and unwieldy, it is not impossible. The simple difference between a Transmission Owner disproving the occurrence of a CCZ incursion and their disproving vegetation caused sustained outages, is that Transmission Owners do in fact keep records of “outages”. Because a Transmission Owner’s record keeping prowess is the only viable option for proving a vegetation caused outage did not occur, SCE respectfully suggests R5, R6 and R7 be revised to read:R5 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation growing into a conductor operating within its Rating with the following exceptions:"R6 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation blowing into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions:"R7 - "Each Transmission Owner shall document Sustained Outages of applicable lines due to vegetation falling into a conductor operating within its Rating and located within an Active Transmission Line Right of Way with the following exceptions: "We also note that Footnote 6 is misplaced in the draft and should follow the word “Outages” in each of these requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 deal with three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Additionally, the Transmission Owner must document and report outages under NERC’s Compliance Guidelines. However, the SDT chose to break the three requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels. **As to the matter of proving the lack of CCZ incursions, please refer to the SDT’s response to your Question # 15 comments.** **Your suggestion regarding Footnote 6 has been incorporated.**		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 16.
Response: Thank you for your comments.		
American Electric Power (AEP)	Agree	AEP is in agreement with these changes.
Response: Thank you for your supportive comment.		
City of Tallahassee	Agree	Why have we gone backwards with only "Sustained Outages" being a violation? Even a momentary outage indicates that a violation has occurred if the cause was vegetation related (with the same exceptions). This

Organization	Agree?	Question 16 Comment
		would seem to contradict the proposed R4. If it wasn't a Sustained Outage it wasn't a violation? If you have a sustained outage due to vegetation, you must have violated the CCZ.
Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.		
Northern Indiana Public Service Company	Agree	While being more specific & explicit, I don't interpret the overall requirement as being any different from the current standard.
Response: Thank you for your comment. Please note that while the current standard did not specifically define an interruption as a violation, the proposed standard explicitly defines outages as violations.		
Orange and Rockland Utilities Inc.	Agree	We agree, but recommend that momentary outages be included as violations of all three requirements as well. Also, the Standard does not directly require reporting of vegetation-related outages although implicitly, outages which are violations of the Standard must be reported. This has lead to some confusion during this comment phase and we suggest that the reporting requirements be directly stated in the Standard.
Response: Thank you for your comments. Under the Compliance section of the new standard section 2 the Transmission Owner is required to report outages.		
Xcel Energy	Agree	We agree, however please add a reference to ?wind gusts 45 miles per hour or greater? to the exception note for this requirement. The exception would read ?1) Sustained Outages of transmission lines that result from sustained winds (45 miles per hour or greater) or gusts due to natural disasters.?
Response: Thank you for your comments. The SDT believes that a fresh gale (see footnote 4) represents an appropriate threshold for exemptions.		
Manitoba Hydro	Agree	Agree with splitting the various events. We note that there is no specific requirement to actually report an outage. The Requirements say that we should Prevent Sustained Outages, but not actually report sustained outages should they occur. In version 1, R3 clearly stated that the Transmission Owner shall report.
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner.		

Organization	Agree?	Question 16 Comment
National Grid	Agree	National Grid agrees with the proposed change, however, Standard FAC-003-2 does not provide outage reporting requirements in R5, R6, R7, or anywhere else in the Standard.
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
Pacific Gas & Electric Co.	Agree	M5, M6 and M7 do not explicitly exclude the exceptions in R5, R6 and R7 and should do so.
Response: Thank you for your comments. The SDT believes that the requirements and measures are properly aligned. The exceptions language is appropriately located in the technical requirement.		
Consolidated Edison Company of New York (CECONY)	Agree	CECONY agrees that outages caused by the factors mentioned are violations of R5, R6, and R7 but we recommend that either the phrase 'momentary outage' be included in the wording or the phrase 'All Outages' replace 'Sustained Outages' to make the requirements clearer.
Response: Thank you for your comments. The SDT very carefully and thoroughly examined the merits, disadvantages, ease and difficulties of assessing momentary outages as a violation. The result of that effort led to the more precise and field observable aspects of R4. It should be noted that by their very nature the exact causes of "momentary outages" are very challenging to determine and will vary widely from utility to utility. The SDT did not find that such variability was appropriate for a reliability standard, and chose to address this issue with the language in R4.		
WECC	Agree	However reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1
Response: Thank you for your comments. Under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. The revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.		
CenterPoint Energy	Agree	We agree with the exemptions; however, R6 and R7 refer to an "Active Transmission Line Right-of-way" which is not defined as to its limits, so M6 and M7 cannot be determined by definition. See comments to Q3 above relating to the definitions and the examples in the Technical Reference.
Response: Thank you for your comments. The SDT asserts that the Transmission Owner is responsible for defining the Active Transmission Line Right of Way. Additionally please refer to the response to Question 3. Note that the SDT made significant changes to clarify R5, R6 and R7 and the associated		

Organization	Agree?	Question 16 Comment
measures.		
Pepco Holdings, Inc	Agree	There is no need for three separate requirements if the incident is a Sustained Outage, but there is nothing inherently wrong with the three requirements.
Response: Thank you for your comments. Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.		
Northeast Utilities	Agree	Agree that contacts resulting in sustained outages due to vegetation from within the active transmission line right-of-way should constitute a violation of the Standard. However, this Standard is written for a zero tolerance of any vegetation caused outages or encroachment into the CCZ. One vegetation-caused outage or one CCZ encroachment may not result in a potential Cascading effect. Agree with the use of different violation risk factors (VRF's) and violation severity levels (VSL's) for each of the three outage classes. Also - how are outage violations to be reported - there is no provision in the revision for the reporting process and requirements (specifics on the type of violation). Will this be addressed in the Compliance Section yet to be added? Suggest in both R6 and R7, move the phrase "within an Active Transmission Line Right of Way" to immediately follow "vegetation".
Response: Thank you for your comments. The SDT believes it appropriate to require that the Transmission Owner incur no (applicable) vegetation-related outages. Further, industry regulators generally expect Version 2 to be at least as stringent as Version 1 unless a valid technical rationale is presented by the SDT. **Requirements R5, R6 and R7 have been drafted to address three distinct types of outages which may pose different risks or severity in terms of impact to the electric system. The SDT chose to break the requirements apart to allow application of different Violation Risk Factors and Violation Severity Levels.** **Regarding your question on reporting of violations, under NERC's Compliance Guidelines, any violation of a reliability standard requirement must be self-reported; thus, a violation of Requirement R5, R6 or R7 must result in a report from the Transmission Owner. In addition, the revised standard includes compliance elements, including the need to provide periodic reports of specific vegetation-related outages.** **Your suggested wording change to requirements R6 and R7 was evaluated by the SDT. The SDT asserts that the original wording is appropriate.**		
SERC Compliance Staff	Agree	
ITC HOLDINGS	Agree	

Organization	Agree?	Question 16 Comment
Northern California Power Agency (NCPA)	Agree	
Central Maine Power Company	Agree	
Tampa Electric Company	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
SERC Vegetation Management Subcommittee (VMS)	Agree	
Progress Energy Florida	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Southern Company	Agree	
E.ON U.S.	Agree	
Bonneville Power Administration	Agree	
FirstEnergy	Agree	
MRO NERC Standards Review Subcommittee	Agree	

Organization	Agree?	Question 16 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	
Ameren	Agree	
American Transmission Company	Agree	
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Edison Electric Institute	Agree	
Baltimore Gas & Electric Company	Agree	
Duke Energy Corporation	Agree	
JEA	Agree	
Independent Electricity System Operator	Agree	
Buckeye Power, Inc.	Agree	
Great River Energy	Agree	

17. R8 is a new requirement which separates the implementation of the annual plan from the requirement to have an annual plan. Do you agree with R8? If not please explain.

Summary Consideration: The SDT modified the Requirement for implementation of the work plan (now R9 in the revised standard) after reviewing these comments. Commenters focused on two main areas. First, there was a suggestion that the work plan wording be amended to include a note that it was only required on the Active Right of Way. Requirement R1 clearly limits the scope of the TVMP to work on the entity's Active Transmission Line Rights of Way - and the "annual work plan" is one element of the overall TVMP. The second overriding theme was that the standard be re-ordered to better tie the requirement to have a plan and the requirement to implement a plan. Some commenters suggested that the requirement to implement the annual work plan be embedded as part of Requirement R1, and the SDT did not make this change. The requirement to "have" a TVMP is administrative and the requirement to "implement" the annual work plan is a real-time requirement – by keeping these requirements separate, each requirement can be assigned an appropriate VRF. The SDT is offering for comment a proposed re-ordering of the Standard that provides a more logical sequence to the Standard which, if supported by stakeholders, can be applied to Draft 3 of the standard.

For Draft 2, the SDT also removed the wording "within the extent of its easements and/or legal rights." The justification for removing these words was to remove the possibility that the TO would be held to the maximum criteria or be limited to the minimum criteria outlined in their easements.

R9. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard.

Deleted: R8

Deleted: within the extent of its easement and/or legal rights

Organization	Agree?	Question 17 Comment
Central Maine Power Company		Central Maine Power Company suggests that R9 read as A Transmission Owner shall implement its annual work plan within the Active Right of Way to the the extent of its easements or legal rights.
Response: The SDT thanks you for your response. In response to overwhelming industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
British Columbia Transmission Corp		BCTC understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		

Organization	Agree?	Question 17 Comment
Western Utility Arborists		The Western Utilities understands that it's possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Vegetation Management Subcommittee (VMS)	Disagree	While the SERC VMS agrees in principle, we believe that the Requirement, as written, is "open ended" and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. The SERC VMS suggest that the Requirement be reworded to read: ?Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.?
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
JEA	Disagree	See comment from #3.
Response: Thank you for your comment. Please see the response to comments on #3. .		
Salt River Project	Disagree	The document would be easier to follow if the two elements would be kept together in the same requirement (similar to comments in #4, #6, & #14 above). It makes the standard longer than necessary and creates redundancy.
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
SERC OC Standards Review Group	Disagree	The SERC OCSRG suggests that the Requirement be reworded to read: "Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Rights of Way." Any further verbiage is confusing, ambiguous or unnecessary.
Response: The SDT thanks you for your response. The SDT considered your request at length but feels that the Active Right of Way concept is supported adequately in the definition and elsewhere in the standard. The SDT did, however, remove the last phrase of the sentence, "within the extent		

Organization	Agree?	Question 17 Comment
of its easement and/or legal rights.”		
Florida Power & Light	Disagree	The standard goes to great length to specify the Active Transmission Right-of-Way but omits its reference in requirement R9. The inclusion of this term in Requirement R9 adds consistency to the application of the standard. FPL suggests the following change: "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 in the Active Transmission Line Right-of-Way."
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in the Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Southern Company	Disagree	While we agree in principle, we feel Requirement R9 as written is “open ended” and could be interpreted to be in conflict with the “Active Rights of Way” concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
E.ON U.S.	Disagree	E.ON U.S. believes that the Requirement, as written, is “open ended” and could be interpreted to be in conflict with the "Active Rights of Way" concept. Clarifying the intent for the annual plan to focus on the Active Rights of Way will prevent incorrect interpretations. We suggest that the Requirement be reworded to read: “Each Transmission Owner shall implement its annual work plan for vegetation management within the Active Right of Way to accomplish the purpose of this standard within the extent of its easements and or legal rights.”
Response: The SDT thanks you for your response. The SDT agrees with your comments and has removed the words “within the extent of its easements and/or legal rights”. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity’s Active Rights of Way.		
Exelon	Disagree	Strike "within the extent of it's easement and / or legal rights." This is unnecessary and will cause confusion. The annual work plan as required to be developed per R1.3 requires consideration of permitting, scheduling and regulatory limitations.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
NV Energy (fka Sierra Pacific / Nevada Power Co.)	Disagree	We understand that it is possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
San Diego Gas & Electric	Disagree	We feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement the plan.
Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
Baltimore Gas & Electric Company	Disagree	As in question no. 14 above for R1.2, it would seem to make more sense to combine R1.3 & R9 as follows: "Require development and implementation of an annual plan that?."
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan.		
Pepco Holdings, Inc	Disagree	THE SDT has introduced the term Active Transmission Line Right of Way. R9 should use this term to avoid any misinterpretation.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		

<table>
<tr><th>Organization</th><th>Agree?</th><th>Question 17 Comment</th></tr>
<tr><td>Great River Energy</td><td>Disagree</td><td>GRE both Agrees and Disagrees. GRE agrees with the separation between having an annual plan and implementing it. However, GRE suggests removing all the words after vegetation management.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.</td></tr>
<tr><td>City of Tallahassee</td><td>Disagree</td><td>Combined with Question 6. R9 needs to have the same flexibility that R1.3 has. As written, it could be argued that you have to do everything in your annual plan, AND anything in addition due to the changing conditions. This contradicts what is put forth in the white paper. I would add "as modified per R1.3" after "implement it's annual work plan for vegetation management"</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. The SDT feels that the “flexibility” of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation.</td></tr>
<tr><td>Tampa Electric Company</td><td>Disagree</td><td>Good start. R9 must also address the flexibility which is addressed in R1.3. As written, R9 does not do this. In addition, R9 states "within the extent of its easement and/or legal right..". This could create another set of conflicting criteria, where the utility has a long term "interim corrective action plan".</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. The SDT feels that the “flexibility” of the annual plan is built into the development of the plan and that same flexibility carries through to the implementation. The SDT does agree with the possible confusion the words “within the extent of its easement and/or legal rights” could cause and has consequently removed these words from the requirement.</td></tr>
<tr><td>USDA Forest Service, Southwestern Region, Regional Office for AZ and NM</td><td>Disagree</td><td>This standard needs to be broadened to include evaluation of the good faith efforts by the Transmission Owner to coordinate with the USFS on development of the work plan. A mechanism should be developed to allow the Transmission Owner to evaluate the good faith efforts of the USFS.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. The Standard is a continental reliability standard. While the SDT agrees with you that every Transmission Owner should strive for mutually beneficial relationships with the various landowners and other entities involved in vegetation management, it would be outside the purvey of this effort to outline specific relationships.</td></tr>
<tr><td>Arizona Public Service Company</td><td>Disagree</td><td>APS understands that it’s possible to have an annual plan and not implement it. However, we feel that the document itself would be easier to follow if it was re-organized so that the requirement to have the plan is kept together with the requirement to implement it.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your response. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation</td></tr>
</table>

Organization	Agree?	Question 17 Comment
requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
SERC Compliance Staff	Agree	Vegetation management practices should be extended areas outside of the active rights-of-way (ROW) to the extent necessary to prevent vegetation-related outages. This should include the identification and removal of trees that could impact transmission line operation similar to the practice of identifying danger trees off of the ROW. The requirement as written could serve to reward those entities that, for whatever reason, have insufficient right-of-way widths. From a practical perspective, it should not be necessary to perform clear cutting of non-active ROW, but Entities should be held responsible for any outages that occur due to contact with vegetation within their legal rights to control.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support to remove any wording referring to the easement rights. The SDT agreed with this view and has revised the requirement.		
ITC HOLDINGS	Agree	Clarifying the intent for the annual plan is to focus on the Active Rights of Way will prevent interpretation conflicts
Response: The SDT thanks you for your response. The SDT agrees with your observation, but also points out that the requirement for an annual work plan (sub-part 1.3) is part of Requirement R1, which specifically states its applicability to Active Transmission Line Rights of Way. Therefore, the SDT respectfully feels that your concern is addressed without additionally placing such verbiage in R8 (now R9).		
American Electric Power (AEP)	Agree	AEP agrees with this change.
Response: The SDT thanks you for your comments. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Tennessee Valley Authority	Agree	TVA agrees with Comment Question 17
Response: The SDT thanks you for your comment. The SDT modified the requirement, based on stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
Platte River Power Authority	Agree	The separation allows lower sanctions and penalties to be assessed for a weak plan and higher sanctions and penalties to be assessed for not implementing an annual plan. However, we feel that the standard itself would be easier to follow if it was re-organized so that the requirement to have a plan is kept together with the requirement to implement it.

Organization	Agree?	Question 17 Comment
Response: The SDT thanks you for your response. The reason that the development of the annual plan and the implementation of the plan were separated was to apply the appropriate VRF's and VSL's to each. The SDT feels that the current organization is appropriate because development of the annual work plan is a sub-part of the development of the Transmission Vegetation Management Program and should be separate from the implementation requirement for the annual plan. The SDT proposes a new sequence for the technical Requirements R1-R11 and seeks industry feedback as requested in Question 4 of the Second Comment Form.		
American Transmission Company	Agree	ATC agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "implement its annual work plan for vegetation management." Propose Changes to R9: Each Transmission Owner shall implement its annual work plan for vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Ameren	Agree	We recommend striking, or modifying, the words "within the extent of its easement and/or legal rights" as they may be introducing an unintended compliance quagmire. For example, if the easement is extraordinarily wide but reliability and the work plan do not dictate that the work plan apply to the entire easement, how will compliance be measured? The work plan should recognize easement or legal rights issue. Therefore, the emphasis for this requirement should be to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. If a clarifying sentence is required, we would suggest that R9 stop with the word standard and a new sentence be added, "The work plan should address easement or legal/rights"
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
MRO NERC Standards Review Subcommittee	Agree	The MRO both Agrees and Disagrees. The MRO agrees with the separation between having an annual plan and implementing it. However, the MRO suggests removing all the words after vegetation management.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		

Organization	Agree?	Question 17 Comment
Midwest ISO Stakeholders Standards Collaborators	Agree	We recommend striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. By tagging the words on to the requirement, we are adding unnecessary compliance validation to this requirement for both industry and the regulators. By the way this is written, it could be interpreted different ways. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner would be accountable to manage compliance with this standard and public relations in their service area.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Duke Energy Corporation	Agree	Duke agrees with the requirement to implement the annual work plan, but recommends striking the words "within the extent of its easement and/or legal rights". The emphasis for this requirement is to execute the annual work plan. The white paper already speaks to the point that it is a best practice for utilities to exercise their legal rights. If we agree that the goal is to prevent outages, then we can simply end this requirement with "accomplish the purpose of the standard". Each Transmission Owner will be accountable to manage compliance with this standard.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
CenterPoint Energy	Agree	R9 requires implementation of the annual work plan "within the extent of its [the Transmission Owner's] easement and/or legal rights." All measures and compliance should be determined on this basis as well. This concept should also be carried through the definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone", or for any definition of clearances should the Standard continue to utilize such terms.
Response: The SDT thanks you for your response. In response to industry comments The SDT has removed the words "within the extent of its easements and/or legal rights". The SDT also feels that the Active Right of Way concept is supported adequately in the definition and in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
Progress Energy Florida	Agree	While Progress Energy agrees with the change, the term "annual plan" should be a defined term including threshold elements.
Response: The SDT thanks you for your response. The SDT feels that the annual plan is adequately defined between the descriptions in the Standard (sub section 1.3) and in the technical reference document.		

Organization	Agree?	Question 17 Comment
Southern California Edison Company	Agree	Q17: SCE agrees in part with the inclusion of R9, however, we believe R9 should be revised and renumbered to replace proposed R3. In SCE's view, the act of implementing a Transmission VM program encompasses both inspection and maintenance activities. SCE respectfully suggests that proposed R9 be revised to read: "Each Transmission Owner shall implement and follow its Vegetation Management Program to the extent allowed by existing easement and/or legal rights."
Response: The SDT thanks you for your response. The SDT separates the vegetation inspections from the annual work plan because of partly due to the fundamental importance of the inspection process, and partly because a key purpose of an inspection is to provide input to the formation of the annual work plan. The SDT also points out that the TVMP is comprises the overarching processes and standards for program management, while the annual plan is the specific annual activities to accomplish the goals set forth in the program. In addition, the SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		
FirstEnergy	Agree	FirstEnergy agrees with the intent of R9, but the standard should be clarified by removal of the word "easement". As written the standard is open to interpretation between "easement" and active right of way. It is important to have the term "legal rights" remain in the standard. The Transmission Owner should be held accountable to fully enforce the legal rights outlined in maintaining the active right of way. This will lead to a more reliable transmission system.
Response: The SDT thanks you for your response. Due to industry comments the SDT revised the wording on this requirement to delete the words "within the extent of its easements and/or legal rights". While we agree and state in the technical reference document that clearing to the maximum extent is in most cases the best practice, there are particular situations where a clear cut policy would not be in the best interest of the Transmission Owner or the landowner. The SDT also feels that the Active Right of Way concept is supported adequately in Requirement R1 which limits the scope of the TVMP (and the annual work plan) to the entity's Active Rights of Way.		
Pacific Gas & Electric Co.	Agree	PG&E agrees with the requirement to implement the annual work plan, but recommends removing the language "within the extent of its easement and/or legal rights".
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad support for your suggestion and the requirement has been revised to reflect your suggestion.		
Entergy Services	Agree	Entergy would like to note that requirements R1.3 and R9 are administrative requirements that add marginal value to the reliability of the Transmission System. Since entities are required to have flexible annual plans, deviations from the annual plan only need to be documented and these requirements will be met. Entergy utilizes annual plans as a good practice but sees limited value with the inclusion in this standard.
Response: The SDT thanks you for your response. After reviewing the industry comments there was broad concern that the current wording could		

Organization	Agree?	Question 17 Comment
cause confusion with the wording "within the extent of its easements and/or legal rights". Consequently the SDT agreed with this view and has revised the requirement to address these concerns. The SDT respectfully disagrees that sub section 1.3 and R9 are administrative requirements and only add marginal value to the reliability of the system. Requirement R8 (now R9) is a real-time requirement, not an administrative requirement.		
Nebraska Public Power District	Agree	
Long Island power Authority	Agree	
Northern California Power Agency (NCPA)	Agree	
Northern Indiana Public Service Company	Agree	
Bonneville Power Administration	Agree	
Orange and Rockland Utilities Inc.	Agree	
Manitoba Hydro	Agree	
Consumers Energy Company	Agree	
National Grid	Agree	
Hydro One Networks Inc.	Agree	
Edison Electric Institute	Agree	
Consolidated Edison Company of New York (CECONY)	Agree	
WECC	Agree	
Independent Electricity System	Agree	

Organization	Agree?	Question 17 Comment
Operator		
Northeast Utilities	Agree	
Hydro-Quebec Transenergie (HQT)	Agree	
Buckeye Power, Inc.	Agree	
Santee Cooper	Agree	
Associated Electric Cooperative Inc.	Agree	
NPCC	Agree	
WECC Reliability Coordination	Agree	
Western Area Power Administration, Upper Great Plains Region	Agree	
Kansas City Power & Light	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Progress Energy Carolinas	Agree	
Response: Thank you for your positive response. The SDT modified the requirement, based on many other stakeholder comments, to remove the last phrase, "within the extent of its easement and/or legal rights."		

18. If you have further suggestions for improving this standard or the technical reference document, please offer them.

Summary Consideration: The overall industry feedback provided to this question reiterated concerns expressed in previous comments above. Most were related to the Critical Clearance Zone and associated issues of measurability, enforceability and practicality.

Organization	Question 18 Comment
Associated Electric Cooperative Inc.	R10 and R11: Associated Electric Cooperative Inc does not believe the Reliability Coordinator (RC) is the appropriate entity to determine whether or not selected sub-200 kv transmission lines should be subject to this standard. The planning horizon for the RC is typically much shorter than the time needed to incorporate a sub-200 kv transmission line into a vegetation management program. Associated recommends Planning Coordinator be designated as the applicable functional entity and be substituted wherever Reliability Coordinator appears in the Standard. M1.4: The language in M1.4, requiring immediate communication of an imminent threat to the Transmission Operator, is inconsistent with the Applicability in Section A.4.1.1 which designates the Transmission Owner as the responsible entity. M4: The preparation and retention of inspection reports, imminent threat reports, quality assurance reports, etc. is appropriate. These reports would not, however, absolutely demonstrate the Transmission Owner had experienced no vegetation encroachments into the Critical Clearance Zone. A negative cannot be proven. M6 and M7: The Transmission Owner is again expected to demonstrate a negative to prove compliance. Section C: Associated Electric Cooperative Inc recognizes the Standard, as posted, is a first draft for comments and will likely be revised before submittal for ballot. However, the Compliance section should be posted for an adequate comment period prior to balloting.
Response: The SDT thanks you for your comments. **The drafting team has made significant changes to the draft standard in response to industry comments, including the replacement of RC with PC.** **R1.4 and M1.4 are changed and the inconsistency has been resolved.** **R4 and M4 are changed such that real time observations during inspections and patrols replace the previous condition of proving a negative. In addition, the revised standard does not use the concept of the Critical Clearance Zone.** **M6 and M7 have been changed so that the proof of a negative is not required.** **The SDT had developed compliance elements for the industry to review in the second comment period.**	
NPCC	NPCC requests that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy.

Organization	Question 18 Comment
Response: The SDT thanks you for your comments. The drafting team has made significant changes to the draft standard in response to industry comments. Compliance elements have been added to the second draft of the standard.	
WECC Reliability Coordination	R10 Should a dispute arise, how are those disputes resolved. Who keeps the list. R10 What is acceptable methodology given the lack of interpretation of unacceptable risk of instability(R 10.2) or cascading failures. There is no definition of the consequences if a sub 200kv line is left off the list for vegetation management, and caused a cascading outage or placed the grid at an unacceptable risk of instability.
Response: The SDT thanks you for your comments The drafting team has made significant changes to the draft standard in response to industry comments. **The RC has been replaced with the PC in R9 and R10.** **This standard requires the PC to prepare and keep the list. Requiring the list to be developed in consultation with the TO ensures that the list will be available to the TO for the purposes in this Standard. The revised language should eliminate any disputes as the PC is ultimately the responsible entity for developing the list.** **R10 was revised and now uses terminology that replicates terms within the IROL definition in the NERC Glossary of Terms for reliability standards. The intent is for the PC to use the same methods that determine those lines which are elements of an IROL be used to determine sub 200kV lines which are applicable to this standard.** **While the planning study or similar analysis as cited in M10 could contain errors, it is not the intent of this standard to determine the competency of the PC or the results of PC any PC's analysis.**	
Western Area Power Administration, Upper Great Plains Region	1) Proactive utilities are implementing policies that call for the removal of all vegetation that could grow into the Critical Clearance Zone . Such policies are not without resistance from landowners, environmental groups, etc. One of the arguments used by such groups is that NERC/FERC do not require removal of the trees. It would very helpful if this document included the practice of removing vegetation capable of encroaching within the Critical Clearance Zone as a reasonable or acceptable practice under this Standard. 2) We can foresee a possible public backlash if this Standard is adopted as written. We see many utilities needing rate increases to cover the additional costs of implementing and monitoring the more stringent requirements of this proposal. We also believe that the more stringent requirements will have no noticeable impact on reliability. So you'll have the public paying more and seeing no change in reliability and questioning why.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum vegetation clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The Standard Drafting team has found that this Standard can not establish any legal basis to require Transmission Owners to exercise rights that do no	

Organization	Question 18 Comment
exist within their transmission line easements or permits.	
Progress Energy Florida	To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.** **The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.**	
Kansas City Power & Light	The title and explanation for Table 1 in Attachment 1 is not clear as to it’s usage and applicability. It is being confused with the correlation with a minimum clearance and not as a component or building block of the Critical Clearance Zone. Under R10, there may be other methods for consideration of assessing reliability significance of the sub-200 kV lines other than what is

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	listed. Suggest the Drafting Team consider other criteria that an RC should consider in its processes. R10.2 is redundant with R10.1. IROL by definition are those operating limits that represent instability, uncontrolled separation or cascading. Suggest removing R10.2. Under M1.3 the measure requires the annual plan to cover a calendar year. An annual plan may cover a cycle growing season to growing season using the inspection to verify the next seasons work. Suggest removing the language for calendar year.M5, M6, M7 The measures should be requesting the evidence that it has violated the requirements. Good standing programs should not have to defend good practice by providing useless reports. The FAC-003-1 existing requirement R4 for reporting sustained outages is a reasonable and sustainable method that should be retained.R10 should include a periodic review period of annually. Any requirement to maintain current documentation should have a review period.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **Under M10 (now M11) the language now allows the criteria used in planning studies and analysis to be acceptable measures for R10 (now R11).** **The redundancy in 10.1 and 10.2 you found has been removed.** **The reference to the calendar year that was in M1.3 has been removed.** **M5, M6, M7 language has been changed. These measures now rely on the certification reports to the RE reporting will occur for both full compliance and any violations. The revised standard includes data retention periods as well as more detailed compliance information.**	
Western Area Power Administration, Rocky Mountain Region	1. Further clarification of the definition of the active right-of-way appears to be required. For example, if a tree falls from an area controlled by the utility which is outside of the normal width of the actively managed right-of-way, but this area is not reserved or "intended for other facilities", could this be a violation of a Standards requirement? The narrative discussion within the white paper seems to imply that it is not, but the "intended for other facilities" requirement within Standards definition implies that it would be. 2. As currently presented, FAC-003-2 requires an impractical and unrealistic level of performance from the industry. This level of performance is unwarranted for the overwhelming number and expanse of transmission facilities to which the Standards are applicable. Many of these facilities, such as radial load lines, are not critical Transmission OwnerT or IROL facilities and have a minimal impact on overall grid reliability. The rigorous zero tolerance level of performance is only warranted for those lines that are critical Transmission OwnerT or IROL facilities. 3. The Standards should clearly identify any and all reporting requirements.
Response: The SDT thanks you for your comments. **1. The definition of the Active Transmission Line Right of Way states it is “A strip of land that is occupied by active transmission facilities. This corridor**	

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does not include the inactive Right of Way or unused part of the Right of Way intended for other facilities." This definition is not limited only to those parts of the Right of Way intended for other facilities. The SDT has also further clarified the concept in the white paper. **2. Due to the directive given by FERC Order 693 your suggestion for removing some lines above 200 kV from the Standard's Applicability was not considered. (Excerpt from order 693 paragraph 706 "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability").** **3. Reporting requirements are included in standard in the second posting.**	
Progress Energy Carolinas	To avoid interpretation errors and provide clarity, the Applicability section for Facilities (4.2) of FAC-003 should include a statement that the standard only applies to vegetation within the Active Transmission Line Right of Way. For example, a fall-in from outside of the Active Transmission Line Right of Way that causes a sustained outage is not a violation of this standard. Any encroachment/outage initiated by vegetation falling from outside of the Active Transmission Line Right of Way should be excluded from violations. The Critical Clearance Zone concept is academically elegant, but when applied in the field, it presents significant implementation, interpretation and enforcement issues: the complexity of determining compliance could have the unintended negative consequences to reliability; removal of vegetation will likely be delayed because of the complexity and accuracy required to determine compliance prior to tree removal; certification that no violations have occurred will require lengthy and costly calculations and survey measurements; the standard refers to Ratings in the determination of line sags and Ratings is not a tightly defined term, PRC-023 requires relays to hold lines in beyond the line Ratings; how will PRC-023 requirements be factored into the Critical Clearance Zone concept. The Critical Clearance Zone concept introduces more complexity and ambiguity into the standard than it resolves. The drafting team needs to develop an alternative to the Critical Clearance Zone concept that is simple, easy to apply and clearly defines at what point a violation occurs. There are over 158,000 line miles of AC Transmission above 200kV in the United States, covering a Right of Way area potentially as large as 3,000 to 4,000 square miles (an area roughly equivalent to Rhode Island and Delaware combined). With billions of stems of managed vegetation, in and along the right of way, even six-sigma performance would result in a number of outages on a system this large. With countless VM processes and assessments that take place daily, it is unrealistic/unreasonable to expect zero-tolerance for random vegetation events (the transmission system is planned/operated to handle at least any single contingency).
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff, because Standard revisions may not lead to less emphasis on reliability.** **The PRC-023 Standard seeks to ensure that transmission protective relays are properly set such that they do not trip a transmission element unnecessarily. This FAC-003 Standard seeks to prevent vegetation related Sustained Outages by requiring Transmission Owners to maintain their**	

Organization	Question 18 Comment
Active Transmission Line Rights of Way to be sufficiently clear. These two Standards are not mutually exclusive nor conflict with each other.	
Southern California Edison Company	SCE notes that Section C (Compliance) is incomplete and that the associated levels of Non-Compliance listed in FAC-003-1 may be different from those proposed for FAC-003-2. SCE reserves the right to revise its initial comments and submit additional comments regarding the requirements, measures and compliance portions of FAC-003-2.
Response: The SDT thanks you for your comments. Draft 2 will be a complete Standard for you to review.	
SERC OC Standards Review Group	The SERC OCSRG recommends that the definition of "Active Rights of Way" be revised as follows: "A strip of land, designated by the Transmission Owner, that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way set aside by the Transmission Owner for other facilities or uses." The SERC SOSRG recommends that this standard should exclude radial to load facilities and, for consistency, all 200 kV and above lines should not be included in the standard unless they meet the same requirements as sub 200 kV lines.
Response: The SDT thanks you for your comments. The SDT opted to retain the "bright line" of 200kV without further qualifications such as radial to load transmission facilities, due to the directive given by FERC Order 693 (paragraph 706 "we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability".	
Western Utility Arborists	Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. ADDITIONAL COMMENTS We have prepared, and will submit via email, additional comments regarding our online submission. If the ability to submit them electronically is not available on this website, we will send the complete document via email to Harry Tom and would ask that it be reviewed and considered by the drafting team.
Response: The SDT thanks you for your comments. The phrase in R1.4, "and may include actions" has been removed from the revised standard in support of your suggestion. **Please refer to the various responses to your comments provided in the individual questions. The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various comments.**	
Florida Power & Light	FPL believes the Vegetation Management standard should concentrate on grow-in tree issues that contribute to cascading or blackout events as stated in the purpose statement. Fall-in trees from either on or off ROW do not in-and-of themselves cause cascading or blackout events. Transmission systems are appropriately designed to handle incidental outages under N-1 conditions which are the case in fall-in type outages. Requirements relating to fall-in and blow-in outages (R6 and R7), which deal with incidents resulting from

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	force majeure or acts of God, should be removed to allow resources to be allocated to addressing events related to grow in interruptions. Because of an utter lack of control or such situations, no Standard or regulation places a duty on one to control force majeure or acts of God, yet that is precisely what R6 and R7 intend to do. If R6 and R7 stay in its current form, this will be yet another reason why this Standard as written will be unenforceable. FPL recommends the following approach. The entire US Transmission system was built under the National Electric Safety Code (C2). That code uses the Reference Component as the initial building block for establishing the lowest height of a conductor for all operating and designed environmental conditions. Over most open land this distance is 14 feet. FPL recommends creating a new requirement to clearly define a trimming standard. New Requirement At time of trimming, trees under conductors should be trimmed or removed so that the average growth would remain below the Reference Component of Rule 232 in the National Electric Safety Code C2. The wire zone should extend to the blowout distance calculated at 39 miles per hour (Fresh Gale) not to exceed the Active Transmission Right-of-Way. Where the Transmission Owner can not achieve that clearance, they shall have a permanent (ex. raised conductor) or interim (ex. short trim cycles) corrective action plan in place to prevent tree wire conflicts. Permanent corrective action plans should reside in the Transmission Owner's vegetation program record keeping system (database) for application when that line is maintained or inspected. Trees to the side of the ROW should be maintained at the edge of the Active Transmission Right-of-Way. The value in this approach is in its application by arborists and tree trimmers in field conditions. This approach is clear and measurable without a surveyor or an engineer present. The line design calculations were made to the NESC Standard at the time the line was built and incorporate all potential conductor locations within its flight path. As it stands now if there is a violation to R4, R5, R6, or R7 it is already too late. The standard should seek to identify and correct poor performers before they create a reliability threat to the system. In the field, a poor performer has many trees close to the line and will have to do many emergency cuts. It will also have more momentary interruptions before it has a single Sustained interruption. Sustained Interruptions have a history of contributing to cascading and blackout events. The standard should measure performance and penalize poor performance. The changes below reflect performance measurements with a graduated penalty applied to the metric. Change R2 to read 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 tree / conductor distance is less than the minimum clearance distance as specified in Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees). Transmission Owners are to document and report activation of the Imminent Threat Procedure for violation of Table 2. Activation of the Imminent Threat Procedure for other causes shall not be reportable. The Violation Severity level should read: Activation of the Imminent Threat Procedure for encroachment of Table 2 of ANSI Z133.1-2006 (the minimum approach distance for qualified line-clearance arborists or qualified line-clearance trainees) has the following severity level: Lower ? Greater than 5 per 1000 miles of line and less than 7 Moderate ? Greater than 7 per 1000 miles of line and less than 9 High - Greater than 9 per 1000 miles of line and less than 13 Severe - Greater than 13 per 1000 miles of line

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	Trees inside of Table 2 can only safely be trimmed under a clearance from the system operator, using special techniques under a line right of way from the system operator, or by a lineman with a live line permit from the system operator. No utility wants to let a tree get so close to energized lines such that it has to take the line out of service for a tree trim. It should be noted that Table 2 represents an established industry standard which is normally found placarded on the side of every tree trimming easement truck and bucket truck. It is minimum knowledge for every qualified line-clearance tree person under OSHA regulations. This is a distance that field personnel understand. New R5 to read: Each Transmission Owner shall minimize Momentary Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Having Momentary Outages Greater than 3 per 1000 miles of line and less than 6 Moderate ? Having Momentary Outages Greater than 6 per 1000 miles of line and less than 8 High - Having Momentary Outages Greater than 8 per 1000 miles of line and less than 12 Severe - Having Momentary Outages Greater than 12 per 1000 miles of line New R6 to read: Each Transmission Owner shall minimize Sustained Outages of applicable lines due to vegetation growing into a conductor with the following exceptions:? Sustained Outages of applicable lines that result from natural disasters.? Sustained Outages of applicable lines that result from human or animal Activity. The Violation Severity level should read: Lower ? Moderate ? High - Having Sustained Outages Greater than 1 per 1000 miles of line Severe - Having Sustained Outages of 2 or greater per 1000 miles of line These VSL's listed above constitute a strawman for discussion. The drafting team could request historical performance data from Transmission Owners to statistically evaluate where the VSL should be set. As time progresses, future performance data could be re-evaluated to reset the limits. These changes bring the standard back in line with measurable and auditable requirements which provide practical field measurements to the personnel who can make the difference. These parameters provide measurements to indicate the tree health of the system. On a separate note, FPL believes that clarifying information captured in footnotes within the standard should specifically be referenced and made part of the standard. These notes add clarity and better define the standard requirements.

Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive

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industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **The Drafting Team reviewed the exclusion in R6 and R7 and reached consensus that the stated exclusions are adequate to exclude force majeure or acts of God.** **This posting includes under R1 the new section 1.6. That would make the proposal you offer related to maintaining the height of trees above ground level to be a method for the TO to select. The language also allows TOs to select a separation distance between the conductor and the vegetation. When lines traverse terrain with significant changes in elevation within spans the latter method may be more practical.** **Changes made to utilize the MVCD as observed in real time will provide the clarity and measurability you requested.** **R2 has been revised to ensure that the process is used only for conditions that require immediate actions to prevent a sustained outage. Other factors which under some conditions would not pose an imminent threat of a sustained outage were purposely omitted to provide clarity and consistency of application.** **Since R2 is binary requirement its VSL cannot be gradated as you suggest.** **R5 has been left as a binary requirement with a zero tolerance in lieu of a gradated metric in the requirement as you suggest. Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages.** **Momentary outages are purposely not included because of the challenges they pose during investigation. These problems often lead to unreliable, inconsistent, false, or missing reports. Furthermore momentary outages caused by vegetation have not been a historical cause of cascading or widespread outages.**	
Santee Cooper	The SDT should clarify that Transmission lines operated at 200 kV and above is for lines that are network facilities. Radial load transmission facilities operated at 200 kV and above should not be subject to this standard as they would not lead to SOLs or IROLs. M2 requires evidence that a Transmission Owner implemented its imminent threat procedure upon knowledge of a Critical Clearance Zone breach. M4 requires evidence that there were NO encroachments into the Critical Clearance Zone. These two measures are in conflict with one another. If a utility provides evidence for M2 then they are in violation based upon M4.M4 and M5 requires a utility to provide "proof to the negative". These measures should be removed from the standard. R10, R11, M10, and M11 should be removed from this standard as critical facilities are identified through the PRC standards.
Response: The SDT thanks you for your comments. **Regarding your request to line applicability to only network lines above 200 kV FERC in order 693 paragraph 706 stated “we did not intend to make this Reliability Standard applicable to fewer facilities than it currently is with the 200 kV bright line applicability, but to extend the applicability to lower-voltage facilities that have an impact on reliability”. The standard drafting team therefore does not see that honoring your request as one that would be**	

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permissible. **Regarding the conflicts you cite between M2 and M4, please note the revisions in this posting for R2, R4 and the associated measures. The conflict you reference should now be resolved since the distance in R4 is not the exclusive basis for implementing R2 and the concept of the "CCZ" has been removed from the revised standard.** **In M4, the language is now changed to remove the "proving a negative" dilemma.** **There is a 200 kV bright line for applicability in this standard; therefore it is appropriate for the applicability for sub 200 kV lines to be determined within this standard in lieu of the PRC standards.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.**	
Southern Company	We would like to re-emphasize our concern over the zero tolerance philosophy of FAC-003-1 which is continued in this proposed revision. FAC-003 has been singled out as the only zero tolerance NERC standard. Compliance should not be based on the encroachment of vegetation into a theoretical, pre-defined zone, but on the occurrence of a sustained outage, as stated in the document's Purpose Statement. We agree with the philosophy utilized in other NERC standards where a clearly discernible compliance event signals a review of the Transmission Owner's plans, policies, and procedures to determine the effectiveness of the entity's programs and spirt toward compliance. Applicability Section 4.2 describes the Facilities pertinent to this Standard. Recommendation is to restructure the sentence by relocating the parenthetical phrase: Transmission lines operated at 200kV or higher, and transmission lines operated below 200kV designated by the Reliability Coordinator as being subject to this standard ("applicable lines") including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities. Requirement R3Recommend rephrasing to say: Each Transmission Owner shall conduct vegetation inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program. Requirement 10The standard does not mention whether or not the results of this specific assessment methodology are supposed to be compiled and maintained. The resulting information could be labeled as sensitive and possibly critical since the loss would place the grid at an unacceptable risk of instability, separation, or cascading failures. If the resulting information becomes auditable (subject to discovery and posting) then precautions must be taken that are comparable to those designed to preserve the integrity of critical assets or critical cyber assets. We would like to express our sincere appreciation and thanks the drafting team for their efforts.
Response: The SDT thanks you for your comments. **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable FERC staff**	

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because revisions to a Standard may not lead to less emphasis on reliability. **The standard has been revised to remove the violation for encroachment into a theoretical zone and is now based on an observed encroachment in real time inside a distance where flashover becomes a possibility.** **The Drafting Team considered the applicability wording with the ("applicable lines") to be acceptable as written.** **R3 has been revised as you recommended.** **The Drafting Team agrees that documentation regarding the methodology used to determine applicability of lines below 200 kV should have similar precautions for confidentiality as other critical assets or critical cyber assets.** **The issue of transmission line applicability is addressed in FERC Order 693.**	
Bonneville Power Administration	There is a typographical error / omission in the Technical Reference on Page 36, which states, "R6. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor with (sic) Active Transmission Line Right of Way) operating within design blow-out conditions) with the following exception: . . . " I believe the intent is for the statement to read "due to the blowing together of vegetation and a conductor WITHIN Active Transmission Line Right of WAY". This change is needed to make the technical reference consistent with R6. as it appears in the Standard, the definition of Active Transmission Line Right of Way on Page 5 of the Technical Reference, as well as the terminology used on Page 37 in describing Fall-into outages. This needs correction.
Response: The SDT thanks you for your comments. The technical reference error is noted and has been corrected by the SDT.	
Public Service Electric and Gas Company	These comments were prepared by Richard Wolowicz, Manager Vegetation Management, on behalf of Public Service Electric and Gas Company ("PSE&G"). PSE&G also joins with and supports the comments filed by the Edison Electric Institute (EEI) in this matter.
Response: The SDT thanks you for your comments. Please see our response to EEI.	
FirstEnergy	FE provides these additional comments for consideration: 1. Regarding the Applicable Facilities - Section 4.2.2 would be more appropriately placed under Sec. 5 "Effective Dates" since it deals with the timeframe the Transmission Owner has to implement its Transmission Vegetation Management Program on sub-200 kV lines.- Section 4.2.3 - We suggest removing this section. First energy does not agree that this standard should dictate the amount of time a Transmission Owner has to obtain compliance with this standard for newly acquired transmission lines. It should be the responsibility of every organization to "self-report" its compliance issues and planned mitigation plans for all standards when they acquire new lines or facilities. If the SDT believes this should be explicitly stated, then it should recommend to NERC that explicit language be placed in the NERC Rules of Procedure. No other standards set timetables for newly acquired facilities and this standard should be no exception. 2. Regarding R1.1, this subrequirement requires the Transmission Owner to specify the methodologies it uses to control vegetation. It

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	should be clear that not all of these methodologies are required to be deployed in every situation (as explained in the white paper pg.12). We suggest rewording the requirement as follows: "R1.1. Specify the methodologies that the Transmission Owner may use to control vegetation." 3. R1.5 requires a process for "interim corrective action" be specified in the Transmission Vegetation Management Program. However, the standard does not explicitly specify that this corrective action be implemented when the Transmission Owner is constrained from performing vegetation maintenance as planned. 4. As written, in addition to the responsible RC, R10 may imply that this requirement is also the responsibility of the Transmission Owner(s) and neighboring RC(s) due to the use of the term "jointly". Also, R10 should require the RC submit the list of designated lines below 200 kV to the Transmission Owner(s) and neighboring RC(s) within a reasonable time-frame after its completion. We suggest rewording and addition of subrequirements to R10 as follows: R10. Each Reliability Coordinator, in consultation with its Transmission Owner(s) and neighboring Reliability Coordinator(s), shall prepare and keep current a list of designated applicable lines that are operated below 200kV, if any, which are subject to this standard. R10.1. The RC shall submit the list to the impacted Transmission Owner(s) within 30 calendar days of completion and/or revision. R10.2. The RC shall submit the list to its neighboring RC(s) within 30 calendar days of completion and/or revision. Lastly, measure M9 will need to add sub-measures for the proposed additions above. 5. Requirement R10 should require that the RC ONLY uses the assumptions detailed in R10.1 and R10.2 to designate a line as significant. Also, R10.1. should reference the IROL methodology standard FAC-011 since it directly ties into this requirement. Also, in R10.2, "grid" should be replaced with "BES" and the term "failures" is not necessary. We suggest re-wording R10, R10.1 and R10.2 as follows: R10. Each Reliability Coordinator shall document its method for assessing the reliability significance of sub-200kV lines and shall be based only on the following: R10.1 Transmission lines whose loss would result in the exceedance of an Interconnection Reliability Operating Limit (IROL) as determined by standard FAC-011. R10.2 Transmission lines whose loss would place the BES at an unacceptable risk of instability, separation, or cascading.

Response: The SDT thanks you for your comments.

The placement of Section 4.2.2 was chosen to allow the TO time to bring those lines into compliance which are identified by future studies well after the effective dates in Section 5.

The SDT chose to leave Section 4.2.3 as it does provide a reasonable time allowance (limitation) to bring the subject lines into compliance. {note for a newly acquired line to have not previously been subject to the standard it may have been 1) owned and operated by a private entity such as a mining company that was not connected to the grid, 2) was a de-energized line not in operation until it was acquired by the TO, 3) was previously operated at

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less than 200kV but was insulated for an operated at 200kv or higher, or 4) some similar situation to 1-3 above} The SDT sees this Section as following the Rules of Procedure Standard Applicability Section as noted on page 9 to "identify any limitations on the applicability of the standard based on electric facility characteristics". **The SDT modified Requirement R1, Part 1.1 as suggested. The standard does not explicitly state that the interim corrective action process in 1.5 must be implemented. The SDT suggests that the other requirements in the standard related to outages and imminent threats and encroachment provide necessary and sufficient incentives for TOs to utilize the process when and if required.** **R9 and R10 (now R10 and R11) have been revised to replace the RC with the PC as the applicable functional entity. The verbiage "in consultation with" has been replaced by "shall consult with its Transmission Owner(s) and neighboring Planning Coordinators to obtain input to develop the list". Since this list is prepared by the PC for the TO to know of any sub 200 kV line(s) that the TO must maintain, the SDT does not see a benefit to adding a requirement that the PC will provide the list to the TO.** **The SDT chose to keep the word "grid" in lieu of BES to avoid confusion related to the fact that the BES generally includes all lines above 100 kV as defined by the Regional Reliability Organization and this standard does not.** **Other changes were made in the language of R9 and R10 to which incorporate parts of recommendations from other commenters and FE. Requirement R10, Parts 10.1 and 10.2 were redundant, and Part 10.1 was deleted and Part 10.2 was translated into a separate requirement, R11.**	
Midwest ISO Stakeholders Standards Collaborators	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes should add the clarity and simplification that your and other commenters suggested was needed for field implementation.	
SERC Compliance Staff	SERC staff continues to find the Applicability section of the standard to be confusing and contentious. While we recognize it is the intent this section to make the standard applicable t all entities that own transmission lines that operate at greater than 200 kV, this section should not be written to be applicable to transmission lines. Only registered entities can be held accountable for compliance with the standards. SERC staff believes the applicability should be rewritten to include Transmission Owners, Distribution Providers, and Generation Owners that own transmission lines with the characteristics defined in Section 4.2. This would eliminate the need to make register, for example, a Distribution Provider that own a 230 kV line that serves load as a Transmission Owner and make them subject to the requirements of FAC-001 and FAC-002. SERC Staff also suggest the applicability could be handled as it is in PRC-005-1 where the applicability is qualified as 'distribution provider that owns..' and 'generator owner that owns..' or in a similar manner that captures the appropriate subgroup but does not include unintended entities. SERC Staff believes a flashover between vegetation and overhead ungrounded supply conductors that occurs, whether or not the

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	flashover results in a Sustained Outage, is clear evidence of an unallowable encroachment of vegetation into the space that should be avoided and thus should be identified as evidence of a violation of the standard. SERC staff has also found that excluding outages resulting from "earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, major storms as defined either by the Transmission Owner?" results in inconsistencies in reporting because of the inconsistency of the Transmission Owners' definitions of same. If such exceptions are to be allowed, a consistent method of determining the acceptability of those exemptions should be pursued.

Response: The SDT thanks you for your comments.

The intent of the Facilities section under Applicability which you suggest is confusing and contentious, was chosen to follow the Reliability Standards direction under Applicably, specifically "if not applicable to the entire North American bulk power system, then a clear identification of the portions to which the standard applies…"

The issue you raise with respect to Distribution Owners and Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that your suggestion will add confusion to the standard." PRC-005-1 properly addresses the coordination needed between transmission protection and the interface with distribution protection at the point of transformation. There is no comparable expectation for vegetation maintenance on the low voltage side of a transmission to distribution transformer to be subject to this standard. Simply put, either someone owns transmission or does not. It is of no matter whether they may also be a DP or GO. Until the functional model includes provisions to state that "all transmission is not equal", the applicability should remain.

Your concern about flashovers that do not result in Sustained Outages needing to be stated as violations of this standard has been discussed at length by this SDT. The interest is to have a Standard that is not subject the levels of uncertainty associated with any automatic operation which is returned to service by either manual or automatic means. These events are very often not possible to identify, many times misidentified often occur during conditions that have several possible explanations (such as high winds blowing conductors together, wind-blown debris, lightning, contamination flashovers during the onset of wind and rain storms) and do not have a historical basis for ever creating a cascading event. Inclusion of these events as violations in the standard could also cause significant additional costs for extensive investigations by TOs to prove their "innocence" for events that any properly designed and operated transmission system should withstand with no more challenge that the far greater number of lightning, and equipment failure events (cross-arms, insulators, conductor splices, poles) nor ever been the subject of momentary opera being.

Members of the SDT attempted to get the TADS reporting requirements to clearly identify those faults on transmission lines that required maintenance to return the line to service. If such a definition was entertained, then a great deal of the uncertainty is cleared. However there are still conditions where trees and poles are found down after apparent high wind conditions in locations remote to the nearest weather reporting station that depend on assumptions as to which fell first the pole or the trees. The zero tolerance nature of this standard and the Penalty Matrix values should not be tied to anything with a high degree of assumption and uncertainty. Therefore the standard has been revised and worded to have the violation of MVCD as observed in real time.

As an added note there is unnecessary confusion caused by simply labeling the automatic operation line operations as momentary, sustained, and/or locked-out. If a line is not reclosed within moments of the automatic interruption, but is later "test closed" was the line truly unavailable? Was the

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reclosing signal/command properly performed initially? Did the TOP ever truly lose control of this line if all that was required was another close attempt? The true nature of the loss of a line is manifested when it is known that a clearance must be issued such that the line is removed from the TOP's control. **The SDT has reviewed the data on vegetation related reported outages on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TOs are supplying supportive information to indicate that the level of any disaster exclusion is sufficient to identify that design criteria was exceeded. Further specifics on the threshold for each disaster would not ensure that weather data would be adequate to support each location/situation.**	
ITC HOLDINGS	V1 was a better written standard and had clear requirements on reporting and who was to report violations etc. When and how are violation to be reported is not mentioned in the V2. The standard should clearly identify all reporting requirements. Standard development should focus on practicality for the field personnel in terms of implementing the standard and enforceability. Version 2 is not as user friendly for field personnel and ambiguous at best which requires an impractical and unrealistic level of performance from the industry. This standard needs to stress that it applies to vegetation within the Active Transmission Right of Way. Vegetation from outside the active ROW, falling through the Critical Clearance Zone should not be a violation. V2 needs further clarification of the definition of the active ROW.
Response: The SDT thanks you for your comments. The issue of reporting has been addressed in the compliance section of the revised standard. **The changes made to R4 focus on the practicality for field implementation that you suggest. The exclusion you request for vegetation falling through the MVCD, regardless of its being form inside or outside the right-of-way, has been added.** **The definition of the active right of way was debated at length and determined to be best stated in its current form.**	
Exelon	Applicability. 4.2.2 is unclear. If 4.2.2 is intended to cover Generator Owner interconnections, say so uniquivocally. Do not rely on future changes to the NERC Registry Criteria or other "global" solutions if the intent is to make the standard applicable to Generation Owners who own generator leads. Exelon would like to reemphasize our concern with implementing the requirements if the Gallet equation derived Critical Clearance Zone is used. ANSI A300 part 1 and part 7 should be part of the standard as they provide independently recognized valid methods and guidance to conduct maintenance on the ROW corridor.
Response: The SDT thanks you for your comments. **The issue you raise with respect to Generation Owners does not appear to be supported when one reviews the definition of a Transmission Owner in the NERC Glossary "The entity that owns and maintains transmission facilities." The SDT is concerned that this suggestion to add the Generation Owner will add confusion to the standard." The SDT does not agree there is ambiguity. Either an entity is a TO or not.** **The Gallet Equations distances were chosen in lieu of ANSI A300 for clearances because the Gallet is a distance that is necessary to prevent flashover.**	

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The ANSI values are related to worker and public safety not flashover between the conductor and the vegetation.	
Central Maine Power Company	The White paper is an important support document and should remain as an attached reference to FAC 003. The white paper should clarify that capable tree species should always be removed from the border zone, except in selected areas where topography includes deep ravines.
Response: The SDT thanks you for your comments. The standard was designed to allow the Transmission Owner the flexibility to design its TVMP. Further, ANSI A300 is also footnoted in the standard as a "best practice". The White Paper will remain a reference for this Standard and text has been added to try to provide additional guidance as you suggest.	
American Electric Power (AEP)	The definition for Critical Clearance Zone (Critical Clearance Zone) on page 2 of the proposed draft Standard does not specify the Rating (summer, winter, normal, emergency, etc.). This suggests that different Critical Clearance Zone s apply at different times of the year and thus that vegetation in the area might be outside the Critical Clearance Zone at certain times of the year and inside the Critical Clearance Zone at other times. AEP suggests that this may not have been the intent of the drafting team. Also, the term "design blowout" is not defined; thus, it appears that it will be up to the Transmission Owner and the auditor to determine the bounds of the Critical Clearance Zone . AEP again suggests that this may not have been the intent of the drafting team. Requirement R9 contains the clause "within the extent of its easement and/or legal rights". This intent of this clause is unclear and its rationale is not obvious. AEP suggests that this clause be removed or at least reworded for clarity.
Response: The SDT thanks you for your comments. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. The verbiage you suggested removing form R8 (now R9) was removed. Finally, the new Requirement R1 should address the concern about sag and blowout in that it talks about planning to keep vegetation out of all positions the conductor may be for all design conditions.	
Platte River Power Authority	The white paper ensures consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations.
Response: The SDT thanks you for your comments. The White Paper will accompany this Version as a Reference document.	
City of Tallahassee	Attachment I. Titles are different between page 8 and 9. Page 8 should have (D) after Distances. Page 9 should have indication that it is "continued" since the table spans multiple pages.
Response: The SDT thanks you for your comments. The SDT has reformatted the table in Attachment 1 of the Standard.	
Northern California	Section A. 5. Effective Dates: This is extremely vague and I would not know the actual effective date. Whose regulatory approval is

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Power Agency (NCPA)	needed? If this is meant to leave flexibility between FERC and the Canadian entities, please write it that way. Most effective dates are clear and concise, i.e., "the first month following approval by FERC". Let's clear this up and avoid a subsequent interpretation request.
Response: The SDT thanks you for your comments. The wording of this portion of the standard (the Standard's effective date) is governed by NERC policy. The process for approval is different in different jurisdictions – some Canadian Provinces approve a standard when it is approved by the NERC Board of Trustees, other Provinces have other mechanisms for approving standards. For entities that operate in the United States, the FERC is the regulator that must approve the standard. As written, the standard will become effective in the United States the first calendar day of the first calendar quarter one year after FERC approval.	
Northern Indiana Public Service Company	While I very much respect the industry commitment and expertise of the drafting team members, the resulting revised standard reflects an effort to "revolutionize" the standard, when an "evolution" of the current standard would better serve the interests of system reliability. The kinds of wholesale changes proposed in this revision evoke real concerns about governmental regulations being a moving target and in many aspects, backs away from requirements that have led to real progress in UVM made since the 2003 blackout. For example, our company has invested tens of thousands of dollars and countless man-hours to comply with provisions of the existing standard only to see them simply done away with under the proposed revised standard. These investments were made based on an industry consensus standard as well as a realization that the requirements were reasonable and essential to improving system reliability. Where is the evidence that the current standard is not working as intended? What has changed in the last few years to warrant a complete re-write of the current standard? Most UVM professionals will agree there are some changes that need to be made to address FERC's concerns and to clarify intent. However, as presently written, I will recommend our T.O. vote against adoption of FAC-003-2.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The Critical Clearance Zone concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Moreover, certain language changes were needed to comply with directives in FERC Order 693. The changes proposed are meant to capitalize on programs already implemented, not to discard them.	
Tampa Electric Company	Good start. However, this will need additional work and review predicated on the above comments.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time.	
Orange and Rockland Utilities Inc.	Clearance 1 has been eliminated from this draft. Version 2 as drafted only requires that Transmission Owners address vegetation that approaches the Critical Clearance Zone . This is essentially equivalent to Clearance 2 in version 1, a minimum clearance. Although unlikely this could result in some Transmission Owners adopting a just in time vegetation management concept that focuses on

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	maintaining minimum clearances, rather than removing incompatible vegetation or achieving greater clearances. Although R1 requires Transmission Owners to design their Transmission Vegetation Management Programs to control vegetation there is no clear requirement to address incompatible vegetation early and aggressively. The drafting team should revisit this and consider returning to some form of Clearance 1 or requiring the Transmission Vegetation Management Program to address removal of incompatible vegetation within their easement rights.
Response: The SDT thanks you for your comments. **The SDT did revisit and reconsider reinserting a Clearance 1. The issue of how and when to remove or control "incompatible vegetation" was also revisited. The SDT decided to leave C1 and the methods to control (or remove) "incompatible vegetation" to the discretion of the TO. Such discretionary measures do not meet the qualifications to be a requirement within a standard.** **Please take a comprehensive look at all the requirements in the standard we are now re-submitting with this posting. Compliance with these requirements will ensure that the TO maintained vegetation such that 1) no controllable sustained interruptions have occurred, 2) no imminent threats were left unaddressed, 3) all the separation distances between the conductors and vegetation every time they were observed were greater than the distance necessary to prevent a flashover.** **Compliance with each of the above requirements can be achieved with inspection and pruning cycles on a frequent basis such as annually, or on a longer term basis such as every 4 years where warranted by local conditions. There are numerous examples in the industry of these different approaches being both appropriate and effective. Just because a "shorter cycle" is utilized, does not mean that a compromised or "just-in-time" concept is has placed the adequate level of reliability of the grid at risk.**	
American Transmission Company	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability. Requirement 1.3: The proposed requirement does not allow enough flexibility for making changes to the Annual Plan. We believe that changes to the Annual Plan should be allowed even if that means delaying something until the next Annual Plan. Our Proposed Changes: Have an annual plan that identifies the applicable lines to be maintained and associated work to be performed. Adjustments to the annual plan are permissible. We believe that our proposed language accomplishes the SDT's intent while allowing for appropriate flexibility.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes, including the removal of the concept of the CCZ, address and provide the clarity and simplifications you suggest are needed for field implementation of the standard. R1.3 has been revised for to provide clarity. **These R1.3 changes do not explicitly remove the "within the year" clause as you requested, however we do not see the inclusion of that language as restricting appropriate flexibility. It is expected that the annual work plan will be flexible to adjust to changing condition and findings which occur after the plan is first issued for the year, then adjusted within the year as appropriate. Adjustment made within a year may mean accelerating work to the current year that was not in the current year's plans as well as extending work that was initially planned for this year into the future. And when**	

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disasters occur, the SDT has addressed an appropriate extension.	
Xcel Energy	Attachment 1, Table I- Change the title of the table from "Proposed Minimum Vegetation Clearance Distances" to "Critical Clearance Zone Distances". The reason being is that the general public could interpret this table to mean that this is all the clearance that is required by a utility at the time of pruning. Section C, Violation Severity Levels- There is some inconsistency between the C.2 chart and the contents of the Standard and the White Paper. For example, the White Paper specifies that an exception to an R6 blowing together violation would exist for sustained winds of gusts of 45 miles per hour or greater. As to R7, the Standard itself notes that a violation only occurs if the vegetation falling into the line is from within the ROW ? C 2 does not incorporate that requirement. There are two approaches: either note the exemptions within the C 2 chart, or add a footnote to the chart along these lines: "This chart summarizes various provisions, the details of which are more fully set forth in the Standard and White Paper?. We would recommend the later approach. General suggestions: 1) It appears that the FAC-003 Standard is the only "zero tolerance" standard, in some respects. Is this reasonable? 2) There appears to be "advisory" language in this version of the Standard. This type of language should be part of the White Paper, not the Standard itself. 3) Utilities need more support from FERC to deal with regional roadblocks within the USFS regarding the implementation of IVM. The Memorandum of Understanding is not universally accepted within all regions of the USFS.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment parts of those changes address or remove the issues you raise for exemption and footnotes for Table 1. **Table 1 in not intended to be used by TOs to determine how much to prune. This table provides the actual physical separation distances, which if observed, will ensure that flashover from the line to vegetation will not occur. When conditions exist such that the separation is reduced the risk of flashover will become significant. The risk increases as the separation is reduced. Therefore this value represent a threshold which if not violated will prevent flashover, as such it is a valid physical basis for R4 compliance.** **This standard allows the TO to use any combination of pruning, removals of vegetation at ground level, frequency(cycles) of planned maintenance, enhanced inspections, off-cycle corrective maintenance, etc to prevent violations occurring due to vegetation causing a non-exempted sustained outage or MVCD violation.** **Due to the industry impact that arises from zero tolerance for vegetation-related sustained outages, the Drafting Team tried several approaches but could not find a mechanism in the standard development process to establish a non-zero threshold for outages that was acceptable to FERC staff because revisions to Standards may not produce less emphasis on reliability.**	

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The advisory language in R1.4 has been removed. **The SDT discussed with NERC and FERC the need for support with the USFS issues. The SDT concluded that FERC has no power to change the rights or restrictions within any permit or easement document across privately owned or publicly owned.** **Therefore any efforts to improve permits or reduce limitation on permits or easements on federal lands must be handled through other available methods.**	
Ameren	While FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance, the proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplicity needed by Transmission Owners to implement and regulatory bodies to monitor in a manner that will enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes address and provide the clarity and simplification you suggest are needed for field implementation of the standard.	
Long Island power Authority	1) Disagree with R1.1. The proposed standard is too lenient on the program documentation required for an effective program. R1.1 should include the words " the program will document the program objectives, method of site evaluation, the definition of action thresholds, the control methodologies, and how the monitoring program is established". There is a wide gulf between listing IVM methodologies and a vegetation program implementing A300. 2) CHANGE: Within Applicable Facilities listed in section 4.2 the phrase Transmission Line should be changed to Overhead Transmission Line. The NERC Glossary definition of transmission Line is: " A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances." The accompanying white paper states the standard is addressing the impact of vegetation growth on overhead transmission lines. The intent of this standard is the development and implementation of a vegetation management program for overhead transmission lines only. By specifically stating "overhead transmission lines in Section 4.2 there will be no possibility of an occurrence of an auditor requesting a vegetation management program for underground lines.
Response: The SDT thanks you for your comments. In R1.1 the SDT chose to direct the TO to specify the methods used to control vegetation vs specifying a menu of items that may not be applicable to several TOs due to the limited types of vegetation in their areas. The SDT considered the issue of overhead versus underground and concluded that no further clarification was needed. Further, ANSI A300 is referenced in the Standard as a best management practice. The SDT leaves up to the TO the extent to which it wishes to apply A300.	
USDA Forest Service, Southwestern Region, Regional Office for AZ and NM	I'm having trouble getting comments to "stick" in this section of the form. I have a general concern with the opening paragraph of R1. The wording seems to encourage a Transmission Owner to develop a Transmission Vegetation Management Program in a vacuum. The US Forest Service definitely wants input into the development of an annual work plan and USFS land use authorizations include a requirement for USFS approval of vegetation management plans. It seems much more reasonable to require the Transmission

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	Vegetation Management Program to reflect USFS or any other landowner resource management considerations. This tactic would require more "up front" work, but the end result is a plan which would reflect reasonable landowner input and where the disagreements could be settled ahead of time rather than being left for the night shift. I also believe that some kind of dispute resolution process is needed outside the control of either the Transmission Owner or the USFS. I think that NERC could fill that role very well.
Response: The SDT thanks you for your comments. Underlying landowner rights are outside the purview of this Standard. However, the SDT recognizes the value in "up front" input between landowners and transmission Owners. Notice that in this posting of the standard within Requirement 1 at 1.3.4 the transmission vegetation management program shall "take into consideration permitting and scheduling requirements from landowners and regulatory authorities". Such consideration should aid in addressing the issues you raise.	
Consumers Energy Company	The annual work plan should be designed to avoid vegetation growing into a violation of the Critical Clearance Zone or whatever minimum distance is acceptable. Since the plan can change throughout the year, it needs to be flexible, it should be stated that the plan at a minimum must provide adequate funding to prevent vegetation growth from violating the minimum clearance distance. The flexibility of change should be limited to changing to address emergent needs for vegetation management and not reductions in funding that delay maintenance in the hopes that additional funding at some future point in time will be adequate to remove the backlog of vegetation maintenance. The Purpose of the standard should be revised to state "(To maintain minimum clearance sufficient to avoid any vegetation-related Sustained Outages for all applicable conditions) for all Transmission Lines covered by this Standard" as provided by FERC in Order 693, Paragraph 731. The purpose as stated in FAC-003-2 waters down the intent of FERC to "improve the reliability" and is only applicable to "outages that could lead to cascading".
Response: The SDT thanks you for your comments. The purpose statement language was chosen to explicitly state the outcome to be achieved by this standard. The requirements themselves address, among other things, the Sustained Outages and minimum clearances along with the required supporting language. This separation between the purpose and the requirements appears more appropriate to the SDT. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The essential changes are: The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Further, funding is not an issue addressed by this Standard.	
National Grid	National Grid has the following comments: 1. Transmission Owners should be able to define their own inspection "year" and not be locked into a calendar year time frame. National Grid performs inspections at least once per vegetation growth year. Under our Vegetation Management Program, growth years are not skipped, and our inspections occur prior to new growth every year. For example, a transmission right-of-way may be inspected in December 2008 and the right-of-way is next inspected in February 2010. Under this scenario, the inspections occurred 14 months apart, but only one growth year occurred between inspections, and each inspection is ahead of the next year's growth. Transmission Owners need this flexibility to deal with regional growth rate differences and climate. 2. Section C., Compliance, of Draft Standard FAC-003-2 states "To be added". Issuance of Draft Standard FAC-003-2 should have been delayed for comments until all sections were complete. This section is likely to include the outage reporting and self-certification

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	requirements. Transmission Owners need the opportunity to comment on these items. 3. With the elimination of Clearance 1 and reducing Clearance 2 clearances, there is concern that FERC will view Standard FAC-003-2 as a watered down version of Standard FAC-003-1.
Response: The SDT thanks you for your comments. **1. It is recognized that most work management systems typically allow for planned work to be performed within a "band of dates" around a specific end date, such as one-third or one-fourth of an interval. These partial intervals allow for the normal variations that occur in work scheduling. When work is completed within that band of dates it is considered completed "as scheduled". Compliance to R2 should be examined for the example conditions you offer since you are addressing the implementation of the inspections. If the frequency was stated in the vegetation management program as once per calendar year, and if the work was completed "as scheduled" then the TO would be compliant.** **2. The compliance elements are included with the second posting of the standard and will be subject to stakeholder comments.** **3. Effort were undertaken to address in the standard various elements for outages, imminent threats and clearances in a manner that was responsive to a substantial number of industry concerns. The SDT is striving to meet industry stakeholder concerns with a standard that will be approved by its ballot pool, the NERC BOT, and regulatory authorities, including FERC**	
Pacific Gas & Electric Co.	1) The standard should be clear that it applies to all Federal and Non-Federal land. PG&E further recommends additional language specifically dealing with Federal land such as application of ANSI A300. 2) The standard should specify applicability inside substations.
Response: The SDT thanks you for your comments. This Standard states in the applicability section that all lands are subject to the standard. Further, ANSI A300 is footnoted in the Standard. Substation facilities are not included in this Standard. This will be addressed in the White Paper.	
NV Energy (fka Sierra Pacific / Nevada Power Co.)	These comments were made with collaboration with other Western Utilities in a conference on this topic held in Denver. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins "and may include actions" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. NV Energy and the other Western Utilities support the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. Please refer to the various responses to your comments provided in the individual questions. (R1.4 was modified to eliminate the list of possible actions and the use of the word, "may.") **The changes to the standard in this reposting and the responses to your comments on questions 1-17 are intended to serve as a reply to your various**	

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comments.	
San Diego Gas & Electric	We feel that any advisory-type language should be removed from the standard and replaced with wording that is in a declarative tone. We support the development of the white paper as a way to help ensure consistent interpretation of the standard.
Response: The SDT thanks you for your comments. The advisory-type language has been removed form R 1.4	
Hydro One Networks Inc.	Please see our comments on question 3.
Response: The SDT thanks you for your comments. Please see the response to comments on question 3.	
Edison Electric Institute	Overall Comments EEI strongly believes that companies are responding assertively to the requirements in FAC-003-1 and that the existing standard is effective in supporting an adequate level of reliability. The central issue with FAC-003-1 and the draft version 2 centers on circumstances where vegetation encroachments into clearance zones take place and do not result in interruptions. EEI understands that a potentially broad range of interpretations are being applied to the existing standard, resulting in potential violations due to clearance encroachments of any possible design position of the conductor being violations, as well as Sustained Outages. Version 2 should clarify this issue in the context of focusing the industry in the direction that is most effective in establishing an adequate level of reliability. The technical comments provided by EEI seek to address this critical issue. Quantitative analysis on vegetation-related line outages or violations made publicly available do not support the need for a substantive revision of the standard. Analysis needs to recognize a broader range of facts in a consistent manner. Analysis needs to consider whether violations resulted in a Sustained Outage, whether all outages and vegetation encroachment were voluntarily reported prior to enactment of Section 215, or the facts and circumstances surrounding violations. For example, while some entities may perceive a decline in industry performance, it may be that companies are reporting much more completely than in the past. Much more rigorous analysis is needed before concluding that the existing standard must be made tougher. Rather than focusing on whether the standard should be more stringent, EEI believes that the emphasis in the standard development process should focus on practicality, both for field personnel in terms of implementing the standard, and enforceability. Revisions to the existing standard should therefore seek to a) respond to issues raised by FERC in Order No. 693 b) where possible, clarify ambiguities in the requirements, and c) improve industry understanding, practicality, and enforceability. For example, it is impractical to seek development of a ?bright line? set of performance requirements. The standard needs to recognize both the diversity of the continent in terms of geography, topography, and climate, and the critical need to provide field personnel with workable performance requirements. Bottom line; it is very important to recognize that the ultimate goal of the standard is to ensure that vegetation management is conducted in order to maintain an adequate level of reliability, and the industry is achieving this goal. The standard should aim for increasing clarity in the requirements without sacrificing flexibility, since companies expect high monetary penalties associated with Sustained Outages caused by vegetation. In addition, a continued ?zero tolerance? approach to vegetation management will emphasize operational excellence. Seeking ?zero tolerance? on momentary outages is equivalent to pursuit of

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	operational perfection, which is achievable only at extraordinary expense to customers. Therefore, the Standard will be most effective if its elements encourage proactive behavior and provide incentives for Transmission Owners to identify and address vegetation clearance issues before they result in momentary interruptions or Sustained Outages. Vegetation Outage Data In Order No. 693, Paragraph 732, FERC ordered NERC to collect and analyze transmission outage data to inform development of the revised standard. EEI encourages the drafting team and NERC Standards Committee to request that NERC collect and analyze this critically important information. Such analysis provides an important foundation for determining whether the standard can ensure an adequate level of reliability as required by Section 215.Applicability Order No. 693, Paragraph 708, directs NERC to 'develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.' In the order, FERC appears to accept the 200-kv threshold, however, continues to ask about these other critical facilities. EEI recommends that the drafting team develop a definition of 'sub- 200kv critical facilities' for use in the standard. Reliance on Reliability Coordinators for developing their own definition raises the likelihood of inconsistent approaches and applications of the term. In addition, the drafting team should consider whether such critical facilities might require expanding applicability to entities other than Transmission Owners. Annual Plan as a Defined Term In order to aid in compliance enforcement and industry compliance, the term 'annual plan' should be a defined term.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. In the revised standard, to address the sub 200 kV facilities to be subject to the standard, the SDT chose the Planning Coordinator (rather than the Reliability Coordinator) for that task. The Planning Coordinator has the wide area view and appropriate time horizon perspective to identify sub 200 kV facilities. The SDT considered the situation where non-TO facilities such as generator "leads" would be subject to this Standard. There is an ongoing discussion within NERC with regard to registration of Generator Owner's as limited TO's. Annual plans have relevance within this Standard's context and are not needed elsewhere. Therefore a glossary definition is not necessary.	
Consolidated Edison Company of New York (CECONY)	CECONY does not feel that, as currently written, the Standard would effectively enhance reliability throughout the industry. We recommend that stricter language be used in the Standard specifically requiring the industry to remove incompatible species on Active ROWs. This should reduce the number of outages resulting from vegetation grow-ins and vegetation fall-ins from inside the Active ROW and help maintain a higher level of reliability. This is currently done at the state level (in NY) and the revised wording in the Federal Standard may help promote consistency industry-wide and avoid confusion. Also, the concept of the Critical Clearance Zone is theoretically strong but it needs to be made simpler for the auditors and field inspectors.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. We agree with many of your points. The SDT developed R2 to promote proactive behavior by requiring the recording and documentation of imminent threat procedure implementations. The NERC Transmission Availability Data System is set up to collect the outage data as directed by the FERC. . In the revised standard, To address the sub 200 kV facilities to be subject to the standard the SDT chose the Planning	

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WECC	Reporting requirements are not identified in the standard. WECC believes that sustained outages caused by vegetation should be reported to the Regional Entity using the existing reporting requirements in FAC-003-1 (Transmission Owners report outages to the Regional Entity). Reports of sustained outages to the Reliability Coordinator should be made for reliability purposes and not compliance purposes. The Reliability Coordinator should not be required to report vegetation outages of individual Transmission Owners to the compliance department.
Response: The SDT thanks you for your comments. The revised Standard reflects changes in reporting requirements.	
Arizona Public Service Company	APS has a comment to NERC on picking the standard drafting team. FAC-003 is a vegetation management standard not an engineering standard. The team members should have been chosen based on managing the vegetation program not because they were engineers. Any standard that is developed should not contain advisory-type language? it should be declarative in tone. For example, in R1.4, the ending clause that begins “and may include actions” should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. APS supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack of such a paper in the first version of the standard contributed to the varying interpretations by the auditors. The utilities understand however that this document is not a legal document and is not binding.
Response: The SDT thanks you for your comments. The members of the SDT were selected based on their expertise – the following was taken from the SDT Nomination form: **Candidates should have expertise in one or more of the following areas:** - **Transmission line rights-of-way (ROW) vegetation management or ROW maintenance** - **Transmission line design and ratings** - **Regulatory or legal considerations in ROW maintenance** - **Existing codes and good practices in vegetation management** **Most of the SDT members have expertise in vegetation management.** **The SDT has removed the advisory language in R1.4. The SDT has professional foresters, vegetation managers, system operators and regulators.**	
Baltimore Gas & Electric	The Applicability Section of the Reliability Standards (4.2 Facilities) defines the Transmission Lines (Applicable Lines) that must comply to the reliability standard. This section should clearly state that the scope is limited to the facilities that are Bulk Electric System facilities

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Company	consistent with the Bulk Electric System definition as defined by the Regional Entity. Regarding M5, M6, M7:The intention of these paragraphs is unclear to me as written. At first glance, it appeared that the paragraphs were asking for a negative to be proven, e.g. prove that you didn't have any tree-related outages. Anther possible meaning is that utilities have to justify the cause of any outage that may occur. As such, the burden of proof is on the Transmission Owner to provide evidence that an outage was not caused by trees. If an outage were to occur but the Transmission Owner could not find any evidence of the cause, the wording in these paragraphs suggests that by default, the outages will be classified as tree-related. If these paragraphs are intended to assign an outage cause to an outage that has already occurred, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide results of investigation into all transmission outages?? "If these paragraphs are not intended to assign an outage cause to an outage that already occurred, but to provide a mechanism to report outage performance that is currently covered in M3 and M4 in FAC-003-1, then perhaps they could be reworded to say something to the effect of: "Transmission Owner shall provide documentation of tree-related outage performance on a quarterly basis. Investigation results for unknown outages shall also be provided on a quarterly basis." Or as one last suggestion, the wording could simply be: " The Transmission Owner has evidence that there was a Sustained Tree-related Outage?. Regarding the Tech. Reference, I thought that overall it was helpful and will be valuable to help provide guidance for Transmission Vegetation Management Program development and implementation. The area that covers the Active/Inactive R/W should be more clearly explained and illustrated, particularly with respect to the towers with space for another circuit on one side of the structures.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The old M5, M6, and M7 have changed in a manner that should clarify their interpretation as you requested. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are now required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. **Reporting requirements are included in the compliance section with this posting.** **The SDT will attempt to incorporate your suggestions on illustrations for double circuits in the white paper with the final posting of this standard.**	
Duke Energy Corporation	FAC-003-1 lacks clarity that is essential for understanding what is necessary for compliance. The proposed FAC-003-2 needs to be simplified to aid with field implementation and compliance interpretation. Currently, it does not provide the clarity and simplification needed by Transmission Owners and regulatory bodies to enhance reliability.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. The CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. These changes are directed at the clarity and simplification you requested for effective field implementation and compliance interpretation.	
CenterPoint Energy	The proposed FAC-003-2 has gone FAR beyond what was contemplated by the Commission in FERC Order 693 and equates to a total re-writing of the Standard for no apparent reason. The Commission's determination dealt with the following areas: (1) applicability; (2)

<table>
<tr><th>Organization</th><th>Question 18 Comment</th></tr>
<tr><td></td><td>inspection cycles; and (3) minimum clearances on National Forest Service lands. For instance in Paragraph 729, the Commission states, “As proposed in the NOPR, the Commission approves Reliability Standard FAC-003-1 with no proposed modification on the issue of clearances. The Commission reaffirms its interpretation that FAC-003-1 requires sufficient clearances to prevent outages due to vegetation management practices under all applicable conditions?.” Rewriting the minimum clearances introduced a new set of confusing definitions, and further burdens the Transmission Owners with new documentation requirements with little if any benefit when compared to the Clearance 2 concept in the existing Standard. A preferred approach would have been to incorporate the following few items into the existing Standard: (1) the RC versus the RRO; (2) the designation of a specific inspection frequency; (3) the Gallet equation; and (4) the applicability to National Forest Service lands. We agree that the removal of requirements for quarterly reporting of outages, Clearance 1, and personnel qualifications reduces the burden on the Transmission Owners and does not affect the purpose of the standard to prevent vegetation outages. The Standard could meet its purpose and be streamlined by considering the following changes:1. Delete the new terms and definitions for "Active Transmission Line Right-of-way" and "Critical Clearance Zone" and revert back to a Clearance 2 requirement while replacing the IEEE 516 standard distances with the Gallet equation standard distances.2. Delete R2, M2, R4 and M4 which refer to the "Critical Clearance Zone" and rely on R5, M5, R6, M6, R7, and M7 which refer to the prevention of Sustained Outages.3. Delete R1.5 and M1.5 as a requirement and measure, but footnote the "interim corrective action process" as a best practice as was ANSI A300 in R1.1.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Note that the SAR for this project included a list of items to be addressed in the revised standard – and these items included not only the directives in Order 693, but other issues identified during the initial implementation of the standard and during the refinement of the SAR.</td></tr>
<tr><td>Entergy Services</td><td>Entergy requests that the proposed FAC-003-2 revision continue work on clarifying the above mentioned “Disagree” items and appreciates the consideration of the above comments in the development of the standard. A clear understanding of all standard requirements by the industry is needed to make certain field implementation is achieved and that ultimately we improve system reliability.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Those changes were made in part for the clarity that you and others requested in order to ensure that practical field implementation may be achieved.</td></tr>
<tr><td>Alberta Electric System Operator</td><td>The AESO is also a signatory to the joint ISO/RTransmission Owner Council Standards Review Committee comments which reflect our comments to the other questions in the Comment Form.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. Please see the SDT’s responses to the ISO/RTO SRC comments.</td></tr>
<tr><td>JEA</td><td>M5, 6 and 7 ask the entity to prove the negative. This type of evidence is problematic, and may result in nothing better than the entity</td></tr>
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	making an attestation that the event did not occur, thus this measure is not useful. With well over 100,000 miles of transmission covered by this standard, even six-sigma performance would result in vegetation related issues. It is unreasonable to expect zero-tolerance for vegetation events and unnecessary for the industry (and customers) to expend resources to attempt to meet this level of compliance when the transmission system is planned and operated to handle any single contingency, which means that a vegetation contact should not, in isolation, cause a major problem to the bulk power system. This standard needs work to make it clear, unambiguous, feasible and enforceable.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment. **The SDT pursued an approach to develop a metric that would not have a zero-tolerance for outages. Discussion with FERC led the SDT to the conclusion that such an approach would not be acceptable.** **Changes made to the old M5, M6 and M7 in this new draft should alleviate the "prove a negative" dilemma.**	
Independent Electricity System Operator	We recommend removing the Transmission Owner as the one to define a major storm, this task should be left to an applicable regulatory body only, for consistency in assessing such an event. Also, we recommend footnote #5 specify that planned removal of vegetation by the utility is not part of the exceptions, because in our view this activity is a component of the vegetation management program and that outages should be preventable. There is a typo in R6. The numeral "4" should be superscripted.
Response: The SDT thanks you for your comments. Significant changes have been made to the current draft of the Standard based upon substantive industry comment **The SDT has reviewed the data on vegetation related outages that TO have reported on the NERC website. There are 223 reports of outages in that data covering the period January 2004 to March 2009. The associated documentation with these events indicate that TO are supplying supportive information to indicate that the level of any disaster exclusion (including major storms) is sufficient to reasonably identify conditions that exceed design criteria. Further specific on the threshold for each disaster (or storm) would not ensure that weather data would be adequate to support each location/situation.** **Random human error in felling trees whether by loggers, homeowners or vegetation removal crews has not been associated with cascading events and remains a valid exclusion. The related safety risks and equipment damages tend to effectively self-control this type of activity.** **The typographical error in what was R6 (now R7) has been corrected.**	
Salt River Project	We question the method used in determining the clearance distances for Vegetation near Transmission Lines. First is the use of the Gallet Equation. Although the Gallet Equation is more definitive than using IEEE 516 as identified in the current standard, we have questions from an engineering prespective as to how and why this method was chosen for vegetation management. It is stated in the Technical Reference paper that the Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding it's purpose is for designing towers, to define the "tower window" or opening inside of a

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	tower under normal conditions. Because this is not a method designed specifically for vegetation management, what is the basis for applying this to vegetation management? Was there, or could there be testing done? We would find it definitive to substantiate the calculated equation assertions with test data from actual energized flashover distances to vegetation. The testing ought to include dry and misting conditions at 200+ kilovolt levels on a sampling of fresh cut common vegetation types. Reputable EHV testing facilities where such tests can be performed exist within the United States and Canada. Is there additional information to clarify why this method was used to help establish clearance distances for vegetation near transmission lines? Second, it is expected that each utility needs to define their "Critical Clearance Zone". It is outlined in the Technical Reference document how complicated it is to define this clearance area. As the conductor moves throughout its "flight path", the minimum clearance shell surrounding the conductor moves along with it. The shape and size of the Critical Clearance Zone around the conductors 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. 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. There are many variables that are involved at any point along a line and at any given time (loading, operating temperature, wind, maximum design rating, maximum operating loading and so on). 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. Therefore, it seems unreasonable to expect each utility to develop and implement a defensible and auditable clearance zone. We strongly support the development of the Technical Reference document. This would have been helpful if it was available for the first version, as it will help both utilities and auditors. We recommend that this be included in the revised version and subsequent future revisions. Please note that as FAC-003-2 goes through additional revisions prior to finalization, the Technical Reference document needs to be revised to reflect the final revisions prior to implementation.
Response: The SDT thanks you for your comments. The SDT engaged TO personnel who were technical experts with significant experience and credentials in transmission line insulation coordination theory and applications. The purpose of the change to the Gallet derived distances was to provide a set of specific distances that would ensure that flashover would not occur provided those distances were not breeched under expected outdoor operating conditions. These distances are applicable to the wire with respect to structure components, vegetation or any other object at ground potential level. These values have already been proven for dry and wet conditions and need no further testing. **We have made changes in R2 and R4 that should remove the problems you have raised regarding the CCZ and how it is "nearly impossible" to apply under field conditions.**	
Northeast Utilities	In section 4.2.2. the time period for bringing sub 200-kV lines into compliance with the standard states a 12 month period following the designation of the lower voltage lines by the Reliability Coordinator. This can present problems if the RC designates the lines during the course of a plan year, because budgets may not have been established or funded for the additional work. It is suggested that the time period be revised to state, "by the end of the following calendar or budget year after the designation of lower voltage lines", allowing for a full calendar/budget year that can be planned and budgeted to bring lines into compliance.

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	There is concern over the use of the Critical Clearance Zone and making this the "bright line" where encroachment at any time under any conditions is a violation of the standard. The Critical Clearance Zone is a very detailed and calculated zone. It is improbable that an accurate determination of the Critical Clearance Zone could be made in the field. Mere encroachment should not constitute a violation. If the encorachment can be determined and corrected once found - this should be an acceptable practice. It is reasonable for utilities to spend the time, money and manpower to actively manage rights-of-way, and dealing with encroachment issues which can be identified. Many potential encroachments will not be identifiable unless one can accurately identify the Critical Clearance Zone in all cases in all areas at all times. Also, there is some concern over how the requirements are set up for violations of the Critical Clearance Zone and for sustained outages. A sustained outage due to vegetation within the active transmission right-of-way is a violation under R.5, R.6 and R.7. It is also possible that the outage is a violation of the Critical Clearance Zone under R.4. The standard implies that a utility could be assessed multiple violations of the standard for one outage with multiple penalties. Is this the desired intent? Finally, version 1 had clear requirements on what was to be reported, when the reports were required, and who was to submit reports. Is it intended that the standard rely solely on self-reports? Version 2 makes no mention of what is to be reported when a violation occurs, or of any other reports. Is reporting going to be left up to the Regional Entity to establish?
Response: The SDT thanks you for your comments. **The standard was revised to replace the Reliability Coordinator with the Planning Coordinator as the entity responsible for identifying lines sub 200 kV for which there should be a TVMP. By moving to the Planning Coordinator, there should be ample time to address the annual work plan. With its focus on "planning horizon" issues (> 1 year), the PC provides the necessary look-ahead that the RC did not. As soon as a sub-200 kV line is designated as being applicable to this standard, it is understood the subject line could potentially place the grid at risk of instability, separation or cascading. A 12 month period to perform any vegetation maintenance seems reasonable to the SDT.** **Significant changes have been made to the current draft of the Standard based upon substantive industry comment. Items such as the CCZ concept has been replaced with the concept of minimum clearance distances, and Transmission Owners are required to prevent encroachment of vegetation into minimum vegetation clearances distances as observed in real time. Reporting requirements have been addressed in the compliance section of the revised Standard.**	
Hydro-Quebec Transenergie (HQT)	HQT recommends that the Standard Drafting Team review the compliance and reporting requirements for consistency and adequacy. Applicability 4.2.3 contradict first part of Applicability 4.2.1 and that of former Applicability 4.3
Response: The SDT thanks you for your comments. The SDT reviewed your concern and did not see a contradiction.	
BCTC	Any standard that is developed should not contain advisory-type language—it should be declarative in tone. For example, in R1.4, the ending clause that begins "…and may include actions…" should be removed because it is advisory in nature. The suggested actions are not even the responsibility of the vegetation management program. BCTC supports the development of this white paper as a way to help ensure consistent interpretation of the standard. Perhaps the lack

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Response: The SDT thanks you for your comments. R1.4 has been changed to remove the advisory type language.	