NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Vegetation Management FAC-003-2 Standard — Project 2007-07

The Vegetation Management Standard Drafting Team thanks all commenters who submitted comments on the proposed FAC-003-2 — Transmission Vegetation Management Standard. This standard was posted for a 30-day public comment period from September 10, 2009 through October 24, 2009. The stakeholders were asked to provide feedback on the standard through a special Electronic Comment Form. There were 66 sets of comments, including comments from 156 different people from more than 85 companies representing all 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

On January 14, 2010, the NERC Standards Committee endorsed the use of Project 2007-07 Vegetation Management as the prototype for the proof-of-concept for using the results-based criteria for developing a reliability standard. The results-based initiative is intended to focus the collective effort of NERC and industry participants on improving the clarity and quality of NERC reliability standards by developing performance, risk and competency-based requirements that accomplish a reliability objective through a defense-in-depth strategy, while eliminating documentation-driven requirements that do not have an impact on bulk power system reliability.

The Standards Committee directed the Vegetation Management SDT to stop work in refining its second draft of the Vegetation Management standard but to inform stakeholders on how the team had used stakeholder comments to refine the technical requirements carried over into draft 3 of the standard. The drafting team did not develop individual responses to the comments submitted by stakeholders on the second draft of FAC-003-2. Instead, the drafting team produced a special summary report that shows all the questions asked and provides a summary indicating how the drafting team used stakeholder comments submitted in response to that question. The special report is posted on the FAC-003 project page identified in the URL above under the title, “Summaries.”

Index to Questions, Comments, and Responses

The Industry Segments are:

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates (PHI)	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Pat Byrne	Potomac Electric Power Company	RFC	1
2. Dave Paduda	Potomac Electric Power Company	RFC	1
3. Steve Benn	Delmarva Power & Light	RFC	1
4. Olivia Watts	Atlantic City Electric	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council--RSC										X

Additional Member	Additional Organization	Region	Segment Selection
1. Ralph Rufrano	New York Power Authority	NPCC	5
2. Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3. Gregory Campoli	New York Independent System Operator	NPCC	2
4. Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5. Kurtis Chong	Independent Electricity System Operator	NPCC	2
6. Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Saurabh Saksena		National Grid	NPCC					1				
8.	Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	NPCC					1				
9.	Brian D. Evans-Mongeon		Utility Services	NPCC					8				
10.	Mike Garton		Dominion Resources Services, Inc.	NPCC					5				
11.	Brian L. Gooder		Ontario Power Generation Incorporated	NPCC					5				
12.	Kathleen Goodman		ISO - New England	NPCC					2				
13.	David Kiguel		Hydro One Networks Inc.	NPCC					1				
14.	Michael R. Lombardi		Northeast Utilities	NPCC					1				
15.	Randy MacDonald		New Brunswick System Operator	NPCC					2				
16.	Greg Mason		Dynegy Generation	NPCC					5				
17.	Bruce Metruck		New York Power Authority	NPCC					6				
18.	Chris Orzel		FPL Energy/NextEra Energy	NPCC					5				
19.	Robert Pellegrini		The Untied Illuminating Company	NPCC					1				
20.	Michael Schiavone		National Grid	NPCC					1				
21.	Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC					3				
22.	Gerry Dunbar		Northeast Power Coordinating Council	NPCC					10				
23.	Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
3.	Group	Jim Butler	Public Service Co. of New Mexico	X									
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Anne Beard		PNM	WECC					1				
4.	Group	Deborah Schaneman	Platte River Power Authority Vegetation Management Group	X		X		X					
	Additional Member		Additional Organization	Region					Segr				
1.	Scott Rowley		Platte River Power Authority	WECC					1, 3, 5				
2.	Gary Whittenberg		Platte River Power Authority	WECC					1, 3, 5				
5.	Group	John Neagle	Associated Electric Cooperative, Inc.	X				X	X				

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

	Additional Member	Additional Organization	Region	Segment
1.	Chris Bolick	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
2.	John Bussman	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
3.	Kevin Hopper	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
4.	Jeff Neas	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
5.	Gary Highfill	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
6.	Ted Hilmes	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
7.	David McDowell	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
8.	Bill Price	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
9.	Bob Schreiner	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
10.	Ralph Schulte	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
11.	John Settle	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
12.	John Stickley	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
13.	Craig Thomas	Associated Electric Cooperative, Inc.	SERC	1, 5, 6
14.	Kevin White	Associated Electric Cooperative, Inc.	SERC	1, 5, 6

6.	Group	Joe Spencer	SERC Vegetation Management Sub-committee (VMS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Randy Gann	Alabama Power Company	SERC	1, 3, 5
2.	Jeffrey Hackman	Ameren Services Company	SERC	1, 3, 5
3.	Gerald Beckerle	Ameren Services Company	SERC	1, 3, 5
4.	John Neagle	Associated Electric Cooperative, Inc.	SERC	1, 3, 5, 6
5.	Billy George	Duke Energy Carolinas	SERC	1, 3, 5, 6
6.	Robert Trimble	E.ON U.S. Services Inc. for LG&E & KU Companies	SERC	1, 3, 5, 6
7.	Ralph Hale	Entergy	SERC	1, 3, 5, 6
8.	Jim Case	Entergy	SERC	1, 3, 5, 6
9.	Marc Tunstall	Fayetteville Public Works Commission	SERC	1, 3

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Reggie Wallace		Fayetteville Public Works Commission	SERC					1, 3				
11.	Terry Wilson		PowerSouth Energy Cooperative	SERC					6, 1, 3, 5				
12.	Jack Gardner		Progress Energy Carolinas	SERC					1, 3, 5, 6				
13.	Jerry Lindler		South Carolina Electric & Gas Company	SERC					1, 3, 5, 6				
14.	Richard Dearman		Tennessee Valley Authority	SERC					1, 3, 5, 9				
15.	Ron Adams		Duke Energy Carolinas	SERC					1, 3, 5, 6				
16.	Joe Spencer		SERC Reliability Corp.	SERC					10				
17.	Dane Jonas (VMS visitor)		Va. Electric and Power Co.	SERC					1, 3, 5				
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	John Jamrog		Transmission Vegetation/Access Road Mgmt	WECC					1				
2.	Mike Staats		Transmission Engineering	WECC					1				
3.	Jerry Reding		Transmission Line Design	WECC					1				
4.	Marian Wolcott		Transmission Real Property Services	WECC					1				
5.	Jennifer Bailey		Transmission TLM Technical Svcs	WECC					1				
6.	Berhanu Tesema		Transmission Planning	WECC					1				
7.	Mark Newbil		Transmission Vegetation/Access Road Mgmt	WECC					1				
8.	Mike Viles		Transmission Technical Operations	WECC					1				
9.	Dan Tuominen		Transmission Line Design	WECC					1				
10.	Steve Narolski		Transmission Vegetation/Access Road Mgmt	WECC					1				
11.	Frank Weintraub		Transmission Line Design	WECC					1				
12.	Allen Chan		Office of General Counsel	WECC					1				
8.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Rebecca Spach		FE	RFC					1				
2.	Shawn Standish		FE	RFC					1				
3.	Katrina Schnobrich		FE	RFC					1				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Mike Ferncez		FE	RFC					1				
5.	Sam Ciccone		FE	RFC					1, 3, 4, 5, 6				
6.	David Folk		FE						1, 3, 4, 5, 6				
9.	Group	Carol Gerou	NERC Standards Review Subcommittee										X
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Neal Balu		WPS Corporation	MRO					3, 4, 5, 6				
2.	Terry Bilke		Midwest ISO Inc.	MRO					2				
3.	Jodi Jenson		Western Area Power Administration	MRO					1, 6				
4.	Ken Goldsmith		Alliant Energy	MRO					4				
5.	Alice Murdock		Xcel Energy	MRO					1, 3, 5, 6				
6.	Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7.	Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8.	Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9.	Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10.	Scott Nickels		Rochester Public Utilties	MRO					4				
11.	Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
10.	Group	Ben Li	ISO/RTO Council		X								
	Additional Member		Additional Organization	Region					Segment Selection				
1.	Charles Yeung		SPP	SPP Region					2				
2.	Matt Goldberg		ISO-NE	NPCC Region					2				
3.	Patrick Brown		PJM	RFC Region					2				
4.	Bill Phillips		MISO	MRO Region					2				
5.	James Castle		NYISO	NPCC Region					2				
6.	Steve Myers		ERCOT	ERCOT Region					2				
7.	Mark Thompson		AESO	WECC Region					2				
8.	Lourdes Estrada-Salinero		CAISO	WECC Region					2				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Individual	Chip Turner	Tampa Electric Company	X		X		X					
12.	Individual	Michael Davis	WECC RC										X
13.	Individual	Tom Glock-	Arizona Public Service	X		X	X	X		X	X		
14.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
15.	Individual	Derek Vannice	Utility Arborist Association										
16.	Individual	Mary Hetz	Ameren	X									
17.	Individual	Jim Fulton	Vegetation Management Team	X									
18.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
19.	Individual	Silvia Parada-Mitchell	Transmission Owner	X				X	X				
20.	Individual	Hugh Francis	Southern Company	X		X		X					
21.	Individual	James P. Fama	Edison Electric Institute	X									
22.	Individual	Jody Nelson	Georgia Transmission Corporation	X									
23.	Individual	Frank Gaffney	Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Kissimmee Utility Authority	X		X	X	X	X				
24.	Individual	Linwood Blacksmith	Superintendent Transmission Maintenance	X		X		X					
25.	Individual	Weston Davis	Central Maine Power an Energy East Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	James Starling	SCE&G	X		X		X	X				
27.	Individual	Anthony Johnson	Northeast Utilities	X									
28.	Individual	Thomas E. Sullivan	National Grid	X		X							
29.	Individual	Virginia Cook	JEA	X		X		X					
30.	Individual	Richard Dearman	TVA	X	X			X					
31.	Individual	Pat Simons	Idaho Power Company	X									
32.	Individual	Diana Gilman	Lee County Electric Cooperative	X									
33.	Individual	Stephen Tankersley	Pacific Gas and Electric Co.	X		X		X					
34.	Individual	James Manning	North Carolina Electric Membership Corporation			X	X	X					
35.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
36.	Individual	Gwen shrimpton	BC Transmission Corporation	X									
37.	Individual	Larry Akens	TVA	X									
38.	Individual	Rao Somayajula	ReliabilityFirst Corporation										X
39.	Individual	Ian S Grant	Tennessee Valley Authority	X		X		X				X	
40.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
41.	Individual	ron turley	Western Area Power Administration, Rocky Mountain Region	X								X	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
42.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
43.	Individual	Doug Bailey	TVA	X		X						X	
44.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
45.	Individual	Patricia Metro	NRECA - National Rural Electric Cooperative Association			X	X						
46.	Individual	Larry Rodriguez	Entegra Power Group LLC					X					
47.	Individual	David Kiguel	Hydro One Networks inc.	X		X							
48.	Individual	Edward Bedder	Orange and Rockland Utilities, Inc.	X									
49.	Individual	Brian Scott	New Brunswick Power Transmission	X									
50.	Individual	Michael Pakeltis	CenterPoint Energy	X									
51.	Individual	John Humphrey	Nebraska Public Power District	X		X		X					
52.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
53.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
54.	Individual	Russell Hardison	Tennessee Valley Authority	X	X			X				X	
55.	Individual	Kathleen Goodman	ISO New England Inc.		X								
56.	Individual	Martin Bauer	US Bureau of Reclamation					X					
57.	Individual	Jason Shaver	American Transmission Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
58.	Individual	Jack Gardner	Progress Energy Carolinas, Inc.	X		X		X	X				
59.	Individual	Gary Cox	Tucson Electric Power Company	X		X							
60.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
61.	Individual	Karen Powell	Salt River Project	X		X		X	X				
62.	Individual	Steve Rueckert	WECC										X
63.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
64.	Individual	Dan Rochester	Independent Electricity System Operator		X								
65.	Individual	George Czerniewski	Consolidated Edison Company of New York Inc.	X									
66.	Individual	Catherine Koch	Puget Sound Energy	X									
67.	Individual	Jason Lietz	Northern Indiana Public Service Company	X									

1. As stated in the background information above, in response to industry comments, the Requirement for documentation of a TVMP (the new R1) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
Duke Energy	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Co.	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain	Agree	

Organization	Yes or No	Question 1 Comment
Region		
Orange and Rockland Utilities, Inc.	Agree	Although ORU agrees that each TO should be required to have a documented TVMP, we recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, ORU recommends the wording to read, ‘Specify a Vegetation Inspection of at least once per calendar year.’ The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase ‘...and methods to be used...’ should be changed to read, ‘...and methods that may be used....’ to be consistent with the wording in Section 1.1. Also, the terms ‘operating range’ and ‘rated conditions’ in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion.
Southern California Edison Company	Agree	Comments: SCE appreciates and agrees with the Drafting Team’s efforts and approach to revising R1. We agree with the assignment of a Violation Risk Factor of “Lower.” However, we would like to suggest certain revisions (included below) for the sake of clarity.R1. Each Transmission Owner shall institute 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 specify: [Violation Risk Factor - Lower][Time Horizon -Long-term planning]1.1. The methodologies methods that the Transmission Owner may use to control vegetation.1.2. A Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors.1.3. An annual work plan that identifies:1.3.1. The applicable lines to be maintained.1.3.2. The work to be performed and methods to be used.1.3.3. Sufficient flexibility to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible. 1.3.4. Necessary permitting and scheduling requirements from landowners or regulatory authorities. 1.4. A process or procedure for responding to an imminent threat of a vegetation related Sustained Outage. The process or procedure shall specify actions that include communication of the threat to the responsible control center.1.5. An interim corrective action process for use when the Transmission Owner is constrained from performing planned vegetation maintenance. 1.6. 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.
Edison Electric Institute	Agree	EEI generally agrees with changes to draft revised R1. In addition, EEI recommends that the SDT consider an alternative structure for the wording of R 1.6, where the current wording states ‘...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.’ To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, EEI suggests consideration of the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: “Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible

Organization	Yes or No	Question 1 Comment
		locations of the conductor for rated design conditions." Companion M 1.6 could be revised to state: "Transmission Owner has evidence of its consideration of the range of all possible positions of conductors and line loading variables."FERC Order No. 693 does not direct NERC to establish minimum inspection cycles. Rather, FERC stated a goal for the Standard to '...assure that transmission owners conduct inspections at reasonable intervals.' (Order 693, P. 720) EEI recommends the SDT consider an alternative to the proposed annual inspection minimum requirement. In some regions of North America for some companies, or for parts of service territories for some companies, inspections for vegetation issues are irrelevant, or, needed significantly less frequently than an annual basis. At the other end of the spectrum, a company-wide annual requirement could inadvertently 'lower the bar.' On either side of the spectrum, a 'one size fits all' approach may have unintended consequences that challenge the ability for companies to maintain realistic inspection cycles. Therefore, EEI recommends that the SDT consider an alternative to R 1.2 to state that descriptions of inspection cycle frequencies should be included in the vegetation management program annual plan under R 1.3, including reasoning for inspection frequency basis. Should the SDT choose to not revise this requirement, EEI notes that provisions of the Standards Development Procedures manual, both for entity variance and regional variance for an area less than an Interconnection in size (Standards Development Procedures, p. 27), may be an alternative to the extent that vegetation issues within a company service territory, or a geographic area that includes parts of several company service territories, reflect conditions that do not require performance at the level stated within a requirement.Revised draft R 1.6 states that maintenance strategies in companies' vegetation management programs must consider 'sag and sway of the conductor throughout its operating range under rated conditions.'Since neither 'operating range' nor 'rated conditions' are defined NERC terms, this requirement could be open to broad interpretation. As a result, EEI recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests to EEI that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. EEI recommends that the SDT consider additional specificity. If the term 'operating range under rated conditions' is retained, it should be clearly defined. For example, the Requirement could include explicit references to Normal Ratings and Emergency Ratings used in other FAC -class Standards, coupled with a Measurement that a Registered Entity can demonstrate that Ratings applied to FAC-003 are the same as those used elsewhere.
National Grid	Agree	National Grid encourages the drafting team to leave the reference to A.N.S.I. A300 in the standard.
PacifiCorp	Agree	PacifiCorp thinks it is very important for improved reliability to directly reference ANSI A300, rather than relegate it to a footnote. ANSI A300 is science-based, and proven to be effective. Directly referencing adherence to A300 will encourage uniform compliance with FAC-003 across North America. Without this reference, PacifiCorp fears grid stability could be threatened by ineffective practices applied by utilities that lack sufficient expertise to manage their systems. PacifiCorp believes that those utilities could create future

Organization	Yes or No	Question 1 Comment
		blackouts due simply to a lack of understanding about proper utility vegetation management practices. Consequently, PacifiCorp urges direct reference to A300 within the standard. PacifiCorp believes eliminating clearance 1 will be detrimental to reliability. Clearance 1 is important for utilities to account for the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives utilities leverage with landowners, governmental agencies and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance, landowners and local regulators will push the utility to maintain a little more than those clearances rather than properly taking tree growth into account.
Pepco Holdings, Inc - Affiliates (PHI)	Agree	PHI understands that the SDT was responding to FERC Order 693, but feels there has been a one-size-fits-all approach. An approach as taken in PRC-005 could be used whereby the Transmission Owner could state its basis for vegetation maintenance cycles.Neither -operating range- nor -rated conditions- are defined NERC terms; this requirement could be open to broad interpretation. As a result, PHI recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for -all rated electrical operating conditions-. This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. PHI recommends that the SDT consider additional specificity.
Xcel Energy	Disagree	(a) The requirement in R1.2 that mandates an annual inspection is too onerous. Xcel Energy urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, we feel this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, Xcel Energy believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. It is suggested that R1.2 be revised to read as follows: Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local and environmental factors, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.(b) R1.5: the word “temporarily” needs to be removed. Some constraints are not of a temporary nature. One example would be the U.S. Forest Service’s refusal to allow trimming or removal in accordance with the Transmission Owner’s vegetation management guidelines; another exists in the case where the easement or other instrument allowing the Transmission Owner to occupy the land does not allow vegetation management

Organization	Yes or No	Question 1 Comment
		in accordance with the Transmission Owner guidelines. In such situations, an interim corrective action process is appropriate but the word “temporarily” is not.(c) Section R1.6 should be reworded. The existing language is troublesome and confusing. A better alternative would be: "Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions."
MRO NERC Standards Review Subcommittee	Disagree	A. The requirement in R1.2 that mandates an annual inspection is too onerous. The MRO NSRS urges the retention of the provision in the existing standard that allows the Transmission Owner to set the frequency of inspection. In some areas of the country, annual inspections may not be adequate. Yet in other areas, a longer inspection frequency may be perfectly reasonable and practical. Our point is that inspection frequency should not be treated as if it were “one size fits all”. If treated this way, the MRO NSRS feels this could pose a risk to reliability and is not likely to be cost-effective. The Transmission Owner should be allowed some flexibility. However, if the drafting team disagrees and determines that an annual inspection is to be mandated, the MRO NSRS believes that an exception to the annual inspection is appropriate when a non-subjective advanced technology such as LIDAR is utilized to achieve actual clearance distances. This places the Transmission Owner in a situation where it can rationally determine that the objectively measured distances result in a situation where an inspection need not be performed within the next year. Additionally, the MRO NSRS feels “that takes into account local and environmental factors” is explanatory text and is inappropriate for a requirement. It is suggested that R1.2 be revised to read as follows: Specify a Vegetation Inspection frequency of at least once per calendar year, unless the Transmission Owner, based on a non-subjective advanced technology, such as LIDAR, determines that a longer inspection period is appropriate.B. R1.5: the word “temporarily” needs to be removed. Some constraints are not of a temporary nature. For example, the U.S. Forest Service’s refusal to allow trimming or removal in accordance with the Transmission Owner’s vegetation management guidelines, or in the case where the easement or other instrument allowing the Transmission Owner to occupy the land does not allow vegetation management in accordance with the Transmission Owner guidelines. In such a situation, an interim corrective action process is appropriate but the word “temporarily” is not. What happens if it’s more than “temporarily”?C. R1.6 should be reworded. The existing language is troublesome and confusing. A better alternative would be: "Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions." D. R1.3.3 states that the annual work plan shall....”Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.” The MRO NSRS is concerned that the wording would not allow a situation where the work plan is not entirely implemented “within the year”. There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into early part of the following year. We understand that this was the SDT’s intent; however, the text is not clear that it allows for such deferments. We recommend modifying the requirement to read, “Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan including work deferments into a subsequence

Organization	Yes or No	Question 1 Comment
		year's work plan are permissible." E. R1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. The MRO NSRS believes that the term "imminent threat" should be a NERC defined term. F. (R1) Since neither "operating range" nor "rated conditions" are defined NERC terms, this requirement R1 could be open to broad interpretation. As a result, the MRO NSRS recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. The MRO NSRS recommends that the SDT consider additional specificity. Or, we recommend these two terms ("operating range" and "rated conditions") be defined by the SDT.
Consolidated Edison Company of New York Inc.	Disagree	Although CECONY agrees that each TO should be required to have a documented TVMP, we recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, CECONY recommends the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary.
FirstEnergy Corp	Disagree	Although we mostly agree with Req. R1, we offer the following suggestions for improvement:Main Req. R1 - We suggest replacing the phrase "that describes how it conducts work" with "that describes vegetation control methods on its Active Transmission Line Right Of Way". We feel our proposed change more accurately describes the intent of the TVMP.Part 1.2 - We feel the phrase "local and environmental factors" is ambiguous and open to varying interpretations. We suggest R1.2 read "Specify a Vegetation Inspection frequency of at least once per calendar year." (Delete the remainder of the sentence).Part 1.3.3 - Regarding the second sentence "Adjustments to the plan within the year are permissible", we feel it would be clearer if it was changed to simply "Adjustments to the plan are permissible". There may be situations beyond the entity's control, where the work plan is not entirely implemented "within the year". These situations would justify the work being postponed and completed in the early part of the following year. FE believes this change maintains the intent of the drafting team based on the reference White Paper that permits deferral of work for various reasons. Part 1.6 - FE believes that this sub-part of R1 is redundant and and suggests it be removed. The primary R1 requirement text already references the need to consider all possible conductor locations and the effects of swag and sway. Additionally, sub-parts 1.1 - 1.5 will achieve the outcome which 1.6 is seeking. Parts 1.1 - 1.5 identify the strategies used to ensure that Table 1 clearances are not violated, which is accomplished through specifying vegetation control methods, requiring an annual inspection, adjusting the work plan to incorporate the inspection findings, allowing time for permitting and scheduling, having an imminent threat procedure and requiring an interim corrective action process. Requiring the Transmission

Organization	Yes or No	Question 1 Comment
		Owner to meet 1.6 by either identifying vegetation to conductor clearance in addition to Table 1, removing all trees on the active ROW, or managing vegetation at a maximum height, as the SDT has suggested, adds specificity that is burdensome and may lead to greater potential for a Transmission Owner to violate its own TVMP, in addition to the requirements already in place. If the SDT wants to merely assure that the TVMP adheres to the clearances specified in Table 1, then we suggest removing Part 1.6, and adding the following wording after "documented transmission vegetation management program" in the body of the text of main Requirement R1: "that adheres to the minimum vegetation clearance distances specified in Table 1 of Attachment 1".
Northern Indiana Public Service Company	Disagree	As written, the definition of "Active Transmission Right of Way" leaves it up to each T.O. to determine what is "active" and what is "inactive" R.O.W. The dimensions or physical description of these areas for any given R.O.W. are not required to be defined or documented by the T.O. in the TVMP or anywhere else for that matter. This creates the possibility for a T.O. to avoid violations of this standard or to inappropriately reduce maintenance activities by simply declaring that any offending vegetation resides in an inactive area. For Example: The T.O. typically maintains a R/W clear of trees 75 ft. to the side of the conductor. However, over a period of time, the T.O. allows trees to encroach in from the sides in several spans so that there is only 50 ft. of side clearance. A tree 60 ft. to the side in this narrowed area falls into the conductors but the T.O. declares the tree to have fallen from an inactive R.O.W. area since it wasn't actively being maintained. This is a major loophole that needs to be addressed. Am in agreement with R1.1 through R1.4. Disagree with the inclusion in R1.5 of the term "temporarily" when there are constraints on completing vegetation maintenance work. It is unimportant whether or not a constraint is temporary or permanent. What is important is that work cannot be completed as planned. When this happens, the T.O. needs to use a corrective process or implement mitigation measures in response to the constraint. The Technical Reference provides examples of permanent constraints such as "the discovery of easement stipulations which limit the T.O.'s rights" along with temporary constraints. This acknowledges the fact that any constraint, regardless of duration, should be addressed through a corrective action process or mitigation plan.
Oncor Electric Delivery	Disagree	Comments: Part 1.3.3. allows adjustments to the plan within the year but does not allow work to be deferred until the next year. This deferral of work impacts 1.3.1, 1.3.2 (possibly 1.3.4) but does not impact the reliability of the line. “Following the Annual Plan” should accommodate a TO responding to changing conditions (to include permitting and scheduling) and should not necessarily place a TO out of compliance. Are adjustments made outside of the plan year considered to be “missing” in Part 1.3.3 by definition of High VSL for R1?Part 1.3.4 states a TO should consider permitting and scheduling requirements in developing their annual plan. What if a TO took into consideration these requirements and the timing of these issues took longer than anticipated? These types of variables may result in the deferral of some line work until the next year. Requirement 1.3 should clarify what the compliance status of a TO if plan specified line work was not implemented that year due to permitting and scheduling issues?Consider: Adjustments to the plan within

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		the year are permissible. This could be inserted at 1.3 to cover all parts or just 1.3.3 and 1.3.4. In its current state, only 1.3.3 (Changes to conditions and Findings from Vegetation Inspections) is addressed.
Vegetation Management Team	Disagree	Comments: Disagree with R1.2 - Inspection Frequency. Very prescriptive. Please consider allowing TO's to select the frequency that best fits their requirements. BGE currently defines their inspection frequency as annually during the non-growing season, October 1 to May 1. Under the proposed language scheduling would be very challenging. Disagree with 1.3.3 which states that the annual work plan shall "Be flexible to adjust to changing conditions and to findings from vegetation inspections. Adjustment to the plan within the year are permissible."This wording would not allow a situation where the work plan is not entirely implemented "within the year". There may be times where one may be justified to postpone work that is planned for the end of the year to be moved to the first part of the following year. We suggest removing the words "within the year" from R.1.3.3Disagree with R1.6 and M1.6 The purpose of the TVMP is to prevent vegetation related outages and improve the reliability of the electric system. The imminent threat provision allows for a procedure to address imminent threats before they become violations. (R1.4). Therefore, as long as the TO follows the imminent threat procedure, then a violation will not result. A violation will result only if the TO does not have an imminent threat procedure or fails to implement that procedure. Merely having an imminent threat is not a violation. By comparison, the new draft states any observed encroachments are reportable violations because the requirements do not permit a procedure to address encroachments. (See R1.6, R3. R4). The better approach would be to require the remediation of encroachments according to a TVMP but not make every found encroachment a violation. An encroachment is not necessarily "likely to cause a Sustained Outage at any moment," the level of severity required to be an imminent threat. (p.20). It is logical to conclude that imminent threats are more severe than encroachments. In fact, the technical report states that an encroachment due to operation of a transmission line beyond its recognized rating is beyond the scope of R4, the requirement for prevention of encroachments. (p.31). If this is the case, just like the process by which the TO is given the opportunity to address imminent threats, encroachments should also be addressed via a pre-determined process before becoming a violation of the standard. Further the requirement as drafted is a disincentive to deploy more sophisticated tools to identify threats to its system, such as software-enabled LiDAR Therefore, we suggest the following changes to the requirements: R1.6: require a process or procedure for response when any [REMOVE: specify the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that] Table 1 clearances in FAC-003-2-Attachment 1 are never violated are encroached upon.M1.6: The Transmission Owner's transmission vegetation management program documentation specifies [REMOVE: the maintenance strategies used (such as minimum vegetation-to-conductor distance or maximum vegetation height) to ensure that] an encroachment process or procedure for responding if any Table 1 clearances in FAC-003-2-Attachment 1 [REMOVE: are never violated] are encroached upon. The maintenance strategies consider the sag and sway of the conductor throughout its operating range under rated conditions.

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Hydro-Quebec TransEnergie (HQT)	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, 'Specify a Vegetation Inspection frequency.' The minimum frequecy should be left to the TO according to its system and environment characteristics. also, the additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Independent Electricity System Operator	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.If the above suggestion is not accepted, recommend changing the wording in Section 1.2 to read,

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		'Specify a Vegetation Inspection of at least once per calendar year.' Also, the additional wording regarding local and environmental factors may cause unnecessary confusion for some.
ISO New England Inc.	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Northeast Power Coordinating Council--RSC	Disagree	Each TO should be required to have a documented TVMP. Recommend changing the wording in Sections 1.2 and 1.3.2.In Section 1.2, recommend changing the wording to read, 'Specify a Vegetation Inspection of at least once per calendar year.' The additional wording regarding local and environmental factors may cause unnecessary confusion for some. In Section 1.3.2, the phrase '...and methods to be used...' should be changed to read, '...and methods that may be used....' to be consistent with the wording in Section 1.1. Also, the terms 'operating range' and 'rated conditions' in R1.6 should be clearly defined in the Standard and added to the NERC Glossary to avoid confusion. There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be

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		located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
American Transmission Company	Disagree	FERC Order No. 693 does not direct NERC to establish minimum inspection cycles. Rather, FERC stated a goal for the Standard to '...assure that transmission owners conduct inspections at reasonable intervals.' (Order 693, P. 720)ATC recommends that that the SDT drop the "once per year" language from the requirement and replace it with the following language:"Document a Vegetation Inspection frequency that considers local and environmental factors." ATC believes that this language is in alignment with Commission's Order 693 and responsive to maintaining system reliability.The current language a) limits the ability of an entity to set a longer inspection cycle if its local / environmental and b) requires entities to justify the once per year cycle. ATC believes that the SDT needs to address this concern by making modifications to the requirement in order to prevent entities from allocate funds on efforts that do not benefit the BPS. R 1.3.3 states that the annual work plan shall...."Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible."ATC is concerned that the wording would not allow a situation where the work plan is not entirely implemented "within the year". There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into early part of the following year. ATC recommends removing the words "within the year "in R1.3.3.R 1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. ATC believes that the term "imminent threat" should be a NERC defined term. An alternate option is to include the following language "imminent threat as defined by the entity". This makes it clear that the entity is allowed to define the term. ATC recommends that the SDT consider an alternative structure for the wording of R 1.6, where the current wording states '...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.'To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, ATC suggests consideration of the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: "Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible locations of the conductor for rated design conditions."R 1.6 states that maintenance strategies in companies' vegetation management programs must consider 'sag and sway of the conductor throughout its operating range under rated conditions.' Since neither 'operating range' nor 'rated conditions' are defined NERC terms, this requirement could be open to broad interpretation. As a result, ATC recommends that the SDT consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for 'all rated electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. ATC recommends that the SDT consider additional specificity.

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JEA	Disagree	Please review the work being done by the ad hoc committee headed by Gerry Cauley that is attempting to guide standard development towards results or performance based requirements. It seems that vegetation management can be handled by this approach and that the paperwork requirement for a documented policy produces a heavy paperwork burden without requisite benefit to reliability added. However, the requirement for a documented procedure for "Imminent Threats" is appropriate as this is in essense an emergency response planning requirement. The requirement for an annual work plan is also appropriate as it is a requirement to demonstrate that appropriate planning is being done to meet the objectives of this standard.
Public Service Co. of New Mexico	Disagree	PNM prefers the Clearance 1/Clearance 2 setup. PNM does not like the MVCD classification as it implies - to the general public - that the MVCD is the only clearance needed. The distances are extremely small. We as a utility company realize this is only the "minimum" distance however it will not be interpreted that way by others outside our industry. Either go back to the Clearance 1 & 2 designation or change the MVCD name to illustrate the criticality of these clearances. Suggestions: Critical Vegetation Clearance Distance or Imminent Threat Vegetation Clearance Distance.Secondly, PNM believes there needs to be some sort of minimum qualifications for those individuals responsible for development and implementation of TVMP.
Manitoba Hydro	Disagree	R 1.2 states that the TVMP shall “Specify a Vegetation Inspection frequency of at least once per calendar year that takes into account local3 and environmental factors.”R 1.2 should read: “Specify a Vegetation Inspection frequency of at least once per calendar year.” (and remove the balance of the sentence)R 1.3.3 states that the annual work plan shall....”Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible.”The wording would not allow a situation where the work plan is not entirely implemented “within the year”. There may be instances where you may be justified to postpone the work planned at the end of the year and must be moved into the following year, or an alternative strategy assigned, pushing the work even further out. Remove the words “within the year “in R1.3.3.R 1.4 states that a process or procedure for response to an imminent threat of vegetation-related sustained outage is required. The term “imminent threat” should be a NERC defined term. The SDT should consider an alternative structure for the wording of R 1.6, where the current wording states ‘...specify...maintenance strategies ... to ensure that Table 1 clearances are never violated.’To improve clarity and better reflect the intent for this requirement as stated in the Technical Paper, consider the language directly from the Technical Paper (p. 24). Thus, the requirement could be edited to state: “Maintenance strategies must be designed to a) meet the Table 1 clearances in Attachment 1 and b) consider all possible locations of the conductor for rated design conditions.”R 1.6 states that maintenance strategies in companies’ vegetation management programs must consider ‘sag and sway of the conductor throughout its operating range under rated conditions.’ Since neither ‘operating range’ nor ‘rated conditions’ are defined NERC terms, this requirement could be open to broad interpretation. As a result, the SDT should consider alternatives that will reduce potential ambiguity. FAC-003 currently requires Clearance 2 to be maintained for ‘all rated

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		electrical operating conditions.' This suggests that vegetation clearances should be set in a manner such that required clearances will be maintained for conditions that include line loadings at both Normal and Emergency Ratings. The SDT should consider additional specificity.
Progress Energy Carolinas, Inc.	Disagree	R 1.3.3 states that the annual work plan shall...."Be flexible to adjust to changing conditions and to findings from Vegetation Inspections. Adjustments to the plan within the year are permissible."The wording as proposed would not allow situations where the "work plan" is not entirely implemented "within the year", which conflicts with the requirement to be flexible and adjust to changing conditions. To eliminate this conflict between requirements, PEC recommends removing the words "within the year "in R1.3.3.
Lee County Electric Cooperative	Disagree	R1 1.5 - define 'temporarily'. Alternative: Define a maximum period of time. ex: beyond one inspection cycle, or based on environmental conditions, one growth cycle; or based on when access was restricted - when the last or next inspection occurred or is scheduled to occur.
CenterPoint Energy	Disagree	R1 refers to "Active Transmission Line Rights of Way" which are not defined as to their limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the "...Transmission Owner is responsible for defining the Active Transmission Line Right of Way." However, that determination clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase "on its Active Transmission Line Rights of Way" from R1. The phrase, "...considering all possible locations the conductor may occupy under the effects of sag and sway throughout is operating range and under rated conditions" , by itself defines the airspace that must be maintained. R1.6 adds the MVCD distance requirement to the sag and sway geometry further defining the airspace that must be maintained. R1 requires no specific definition of a right of way.As written, R1 does not address how a utility conducts its work to address the fall-in of trees into an adjacent transmission line. The determination of the limits of the right of way are only necessary in the Standard for determining the reporting exceptions for certain Sustained Outages in R8 (fall-in) as evidenced in measure M8 through self-certification reports.The Standard and the Technical Reference provide no specific justification for defining a 1-year inspection frequency in R1.2. The requirement itself does not take into account "local and environmental factors", which may indicate a longer inspection frequency is warranted. The Technical Reference states that the inspection frequency is required to be "at least once per calendar year". The SDT's only justification for this determination is found in its response to 1st Draft Comments, "...the consensus of the SDT is that inspection of any operating transmission line should be done annually... ". This statement alone is not compelling. No further supporting arguments have been provided. CenterPoint Energy believes that this minimum inspection frequency is arbitrary and is not necessary or appropriate for all registered entities. Registered entities are in the best position to determine appropriate inspection frequencies that take into account local and environmental factors found in their service territories. CenterPoint Energy strongly recommends that R1.2 be revised to allow the registered entity to determine the appropriate inspection frequency for their service territory. The

Organization	Yes or No	Question 1 Comment
		revised R1.2 would read “Specify a Vegetation Inspection frequency that takes into account local and environmental factors to prevent Sustained Outages.”
Platte River Power Authority Vegetation Management Group	Disagree	R1. currently says "...under rated conditions". It should say "...under Rated Electrical Operating Conditions" a NERC defined term. Defined as: The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate.Although we appreciate the SDT’s need to address a minimum vegetation inspection frequency as ordered by FERC directive 693, we believe that system conditions vary too widely from utility to utility and even within utilities to specify a Vegetation Inspection (VI) frequency of at least once per calendar year in R1.2. We think the SDT should consider making the minimum VI broader to cover different vegetation types and local factors. R1.3. Should be consistent in wording with R1.1. and R1.2. as follows: 1.3. Specify an annual work plan that shall:We agree with the SDT to remove the ‘fill in the blank’ requirement for personnel requirements in FAC-003-1.R1.3.2. "Identify the work to be performed and methods to be used", is redundant as it is address in other requirement in the standard. The work to be performed is included under R1. “...that describes how it conducts work” and the methods to be used is included under R1.1. Specify the methods that the TO may use to control vegetation. R1.3.3. Should read: Be flexible to adjust to changing conditions of the vegetation on the Active Transmission Line ROW, emergencies, and other significant changing conditions found during Vegetation Inspections. Adjustments to the plan within the year are permissible but must always ensure the reliability of the electric transmission system.R1.4. Should be consistent in wording with R1.1. and R1.2. as follows:1.4. Specify a process or procedure...We believe that mitigation measures in R1.4 of FAC-003-1 are better than the new corrective action process in R1.5 of FAC-003-2. However, if it is decided to keep R1.5. the SDT should remove the words “interim” and “temporarily” as they do not provide clarity. Some constraints are permanent or long-term and it would be appropriate to have a corrective action process to address all constraints. R1.6. currently says, "... under rated conditions". It should say, "... under Rated Electrical Operating Conditions" a NERC defined term. We have some concern that the general public will misinterpret the Table 1 clearances in Attachment 1 and expect constant maintenance in order to allow their vegetation to be as close to line as possible at all times. The addition of a critical clearance distance to be achieved at the time of work, similar to the Clearance 1 in FAC-003-1 may explain why you need more clearance distance.
Transmission Owner	Disagree	R1., 1.3.,1.3.2. Should read: Identify the work to be performed. The method does not contribute to reliability and places an un-needed burden on auditor and Transmission Owner. R1., 1.4. The term Imminent Threat is vague. FPL recommends that the Transmission Owner should be directed to define it based on its construction and local environmental conditions.
Salt River Project	Disagree	R1.3: In “Require an annual work plan” recommend changing the word “require” to “define”. R1.5: This appears to replace the old R1.4. Suggest changing back to how it was worded in R1.4, a better description.

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		As there was a need to replace “mitigation” and alternative would be to place with “corrective action”.
Puget Sound Energy	Disagree	Requirement 1.6, while a good theory statement, does not have the impact of Clearance 1 in the existing standard. When agencies and reluctant landowners look at this standard, they will not see this requirement the same way Clearance 1 is seen. Requirement 1.6 will be seen as a procedural, not a justification for utilizing utility best management practices for vegetation management. R1.6 indicates that the maintenance strategy used must be specified and then identifies “minimum vegetation to conductor distance” as an example strategy. The minimum vegetation to conductor distance as table 1 is titled is the goal of the strategy, but not a strategy. This creates confusion regarding the intention of this requirement. Modify R1.6 to read “Ensure Table 1 Attachment 1 clearances are never violated considering sag and sway of the conductor throughout its operating range under rated conditions and local vegetation characteristics and factors under non-storm weather variances.” Because the distances in Table 1 are so small, it could appear to a non-familiar customer or local agency that the standard is becoming less stringent raising even more opportunity for customer resistance and the need to create more unique interim corrective actions to manage. The inability of an entity to follow a consistent plan raises the risk of non-compliance.
Central Maine Power an Energy East Company	Disagree	Suggest that NERC define operating range and rated conditions.
Nebraska Public Power District	Disagree	The requirement in R1.2 should allow the Transmission Owner to set the frequency of inspection. The T.O. should be able to determine what frequency based on their system. We also agree with Xcel on an exemption if new technology such as LIDAR is used. This will allow the T.O. to determine objectively what vegetation needs to be addressed and when.R1.4: “imminent threat” needs to be defined.R1.5: delete “temporarily” from the requirement. This is a difficult word to define and provide guidance on.R1.6 should be reworded using language from the Technical Paper (p. 24). “Maintenance strategies must be designed to (a) meet the table 1 clearances in attachment 1, and (b) consider all possible locations of the conductor for rated design conditions.”
Utility Arborist Association	Disagree	The Utility Arborist Association (UAA) considers it imperative to include a requirement for transmission operators to adopt the science-based, industry accepted practices in ANSI A300. ANSI A300 was designed to ensure appropriate and effective practices are implemented, while allowing each utility the flexibility to develop a program that considers site specific factors. The UAA recognizes that there are varying levels of technical competency within the industry among individual utility vegetation management (UVM) programs. While the majority of utilities currently apply A300 routinely, there are still those that do not. We believe that utilities that have failed to implement A300 could potentially become involved in future incidents due to insufficient understanding of effective utility vegetation management practices. The UAA thinks that FAC-003-02 should ensure that all utilities have successful programs to mitigate tree and power line conflicts,

Organization	Yes or No	Question 1 Comment
		regardless of their size, budgets and other available resources. A specific requirement to adherence to A300 will ensure that compliance with FAC-003-02 across North America will be uniform and effective. Without this requirement, we fear that utilities with less robust resources and knowledge may become the weakest link in the electrical system. As such, the UAA strongly encourages the direct reference to A300 within the standard rather than as a footnote.
E.ON U.S.	Disagree	This will add significant cost to vegetation management budgets. The MVCD concept will require the use of LIDAR and will add approximately $250k per year to utility company expenses. These costs include equipment, training, LIDAR survey and personnel costs.
Arizona Public Service	Disagree	Utilities should be held to following ANSI A-300 standards and BMP's for best management practices. By following these standards there wouldn't be a need for the FAC-003 standard. There should not be a footnote but a requirement. Personnel qualifications should be a requirement. There are certification programs through the International Society of Arboriculture that certify a minimum level of competence to manage a vegetation management program. This also requires ongoing training and education to keep up with the latest technologies on UVM. NERC and FERC still need to be aware that federal land agencies are making decisions without any education or knowledge on UVM activities which affect transmission reliability. There needs to be a clearance 1 requirement in the standard. If utilities are required to follow this standard it gives them leverage with dealing with these federal land agencies.
Idaho Power Company	Disagree	We agree with letting the Transmission Owner decide on methods to control vegetation management. We believe personnel qualifications should be included but as determined by the Transmission Owner. We agree that annual inspections should be required. However, we would prefer R1.3 to read as "Specify an annual work plan..." rather than "Require an annual work plan..." to be consistent with the other subsections of the R1 requirements. We believe R1 should allow flexibility to integrate technology, in particular Lidar, as an acceptable patrol.
Ameren	Disagree	Would suggest the term "normal" in front of "sag and sway throughout its operating range"...or " design of" to address the exceptions for environmental conditions.
ISO/RTO Council		The SRC has no comment on this question.

2. As stated in the background information above, in response to industry comments, the Requirement for implementation of Imminent Threat process/procedure (the new R2) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 2 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	

Organization	Yes or No	Question 2 Comment
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	

Organization	Yes or No	Question 2 Comment
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	

Organization	Yes or No	Question 2 Comment
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	PHI agrees with the requirement but notes that Operating Process is a NERC defined term. The SDT should review the definition and use capitalization for Glossary terms.
NERC Standards Review Subcommittee	Agree	Prefer the distances specified in the current IEEE Standard as opposed to the Gallet equation.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement and the assignments. However, it is unclear why the Violation Risk Factor is rated as "Medium," rather than "Lower."
FirstEnergy Corp	Disagree	Although we mostly agree with Req. R2, we offer the following suggestion for improvement. The phrase "actual knowledge" is ambiguous and could be difficult to measure. For instance, if the responsible entity receives a voice mail or email regarding an imminent threat, then that would technically mean he has actual knowledge of the alleged threat; however, only after the entity reviews and confirms the alleged situation can it be judged a true imminent threat. Therefore, we suggest a change from "actual knowledge" to

Organization	Yes or No	Question 2 Comment
		"confirmation".
E.ON U.S.	Disagree	E.ON U.S. believes that requirement to prove "no incident occurred" for an audit would be impossible to accomplishE.ONU.S. believes that the SDT should clarify what is meant by "normal Operating Practices," specifically identifying what practices are necessary to ensure compliance with the standard.E.ON U.S. believes that the proposed standard is in conflict with TOP-1 (the imminent threat procedure could require an operator to take a line out of service thereby putting the grid at risk).
PacifiCorp	Disagree	PacifiCorp thinks it is very important for improved reliability to directly reference ANSI A300, rather than relegate it to a footnote. ANSI A300 is science-based, and proven to be effective. Directly referencing adherence to A300 will encourage uniform compliance with FAC-003 across North America. Without this reference, PacifiCorp fears grid stability could be threatened by ineffective practices applied by utilities that lack sufficient expertise to manage their systems. PacifiCorp believes that those utilities could create future blackouts due simply to a lack of understanding about proper utility vegetation management practices. Consequently, PacifiCorp urges direct reference to A300 within the standard. PacifiCorp believes eliminating clearance 1 will be detrimental to reliability. Clearance 1 is important for utilities to account for the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives utilities leverage with landowners, governmental agencies and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance, landowners and local regulators will push the utility to maintain a little more than those clearances rather than properly taking tree growth into account.
Arizona Public Service	Disagree	The SDT needs to come up with a standardized format for the imminent threat process. All utilities need to be audited the same way. This requirement is too vague since it has a VSL of severe. In the beginning of this document it states the requirement will be clearer and in an unambiguous manner. Here each utility can make up their process and will be audited differently.
BC Transmission Corporation	Disagree	The STD needs to specify a standardized format for the imminent threat process, this will allow for consistency in the audit process which is important because the VSL is severe. If each utility specifies their own process it will be up to the subjectivity of the auditors who often do not have a vegetation management background to determine if the process is adequate.
Lee County Electric Cooperative	Disagree	This requirement seems redundant to R1. 1.4 The process or procedure required in R1. 1.4 includes implementing the procedure. Steps taken to mitigate the threat would be documented and could be considered as implementing the process/procedure. Alternative: either eliminate the new R2 or edit R. 1.4 to

Organization	Yes or No	Question 2 Comment
		include evidence.
ISO/RTO Council		The SRC has no comment on this question.

3. As stated in the background information above, in response to industry comments, the Requirement for conducting Vegetation Inspections (the new R3) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 3 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	

Organization	Yes or No	Question 3 Comment
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	

Organization	Yes or No	Question 3 Comment
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
ReliabilityFirst Corporation	Agree	Do we need the parenthetical statement “as measured in line miles”?
Central Maine Power an Energy East Company	Agree	Inspection frequency should be designed to meet the objective of this standard.
MRO NERC Standards Review Subcommittee	Agree	MRO NSRS suggests that the referenced footnote 5 be modified to include “species epidemics,” such as bark beetles; this footnote 5 should be referenced. Additionally, footnote 5 could be modified to include “species epidemics” between “logging” and “animal severing tree.” R3 states that “Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program, the MRO NSRS recommends that the phrase “of all applicable lines (as measured in line miles)” be removed from R3. This is understood by

Organization	Yes or No	Question 3 Comment
		Applicability section A4.2.
American Transmission Company	Agree	R 3 states that “Each Transmission Owner shall conduct Vegetation Inspections of all applicable lines (as measured in line miles) in accordance with the frequency specified in its transmission vegetation management program,ATC recommends that the phrase “of all applicable lines (as measured in line miles)” be removed from R 3. This is understood by Applicability section A 4.2.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement, but would suggest the following revision to Footnote 4 in order to clarify the text:Examples include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, fresh gale, ice storms, floods, and major storms as defined either by the Transmission Owner or an applicable regulatory body.
Hydro One Networks inc.	Disagree	(a) As compared with the current version, the proposed draft is still excessively prescriptive. Depending on local conditions, an annual inspection may not be necessary. The TO should have the ability to decide on the frequency of the inspections as long as the reliability of the BES is not compromised. For example, vegetation growth in Northeastern North America has long (7-8 months) dormant periods. (b) There seems to be an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TOs to carry out inspections per the frequency defined in its TVMP. According to our comment in (a) above, the TO should have the prerogative of specifying the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, vegetation growth in North Eastern North America has a long (7-8 month) dormant period. The entity should be able to specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period there might be an inspection in November, and an inspection again 14 months later in January. Accordingly, R3 is more appropriate. Other TOs may be located in parts of the continent with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TOs to specify an inspection program that is sensitive to local and environmental factors, not the calendar. (c) In addition, VRFs and VSLs are based on percent of “total line miles specified by its TVMP”; this statement should be qualified by including something like “total applicable line miles specified by its TVMP”, as there may be circuits included in a vegetation management program that are not subject to the FAC-003 standard (sub-200kv, non-IROL lines). This also better aligns with the text of R3 (“...shall conduct Vegetation Inspections of all applicable lines...”). Also, we would suggest explicitly stating line kilometers as an acceptable measure for those using the metric system.
Idaho Power Company	Disagree	Include in the exceptions ‘unless constrained by federal and environmental restrictions’ along with natural disasters. Federal agencies can and have prevented vegetation management measures due to environmental, biological, and/or cultural concerns. In footnote 4, insect infestation should be added as a form

Organization	Yes or No	Question 3 Comment
		of natural disaster. Also, recommend changing 'major storms' to 'major events' in this footnote.
National Grid	Disagree	National Grid sees inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. National Grid prefers that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, National Grid facilities in the northeast are located in an environment where there is a long (7-8 month) dormant period - vegetation does not grow. National Grid would specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO's may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	PHI appreciates the change, however, the SDT has designated the Regional Entity to provide alternate time periods for inspections. This should be the PC or RC. The TO should submit a request for alternate periods to the designated entity.
Salt River Project	Disagree	R1.2 specifies that vegetation inspections are to be conducted at least once per calendar year, yet in R3 it states that the Transmission Owner shall conduct Vegetation Inspections of all applicable lines in accordance with the frequency specified in the transmission vegetation management program. Although SRP conducts its transmission inspections on an annual basis, the Transmission Owner should be allowed to define the inspection frequency based on the operations of their utility company as best defined in their individual TVMP. Whichever definition is approved it should be stated the same in both R1.2 and in R3.
Platte River Power Authority Vegetation Management Group	Disagree	R3 says, "each TO shall conduct Vegetation Inspections of all applicable lines in accordance with the frequency specified in its transmission vegetation management program". However, R1.2. says that the TO shall specify a Vegetation Inspection frequency of at least once per calendar year. The two requirements seem to be inconsistent. We assume that R3 was worded to accommodate a more frequent Vegetation Inspection but it isn't clear.
Hydro-Quebec TransEnergie (HQT)	Disagree	Refer to the response to Question 1.
Independent Electricity System	Disagree	Refer to the response to Question 1.

Organization	Yes or No	Question 3 Comment
Operator		
ISO New England Inc.	Disagree	Refer to the response to Question 1.
Northeast Power Coordinating Council--RSC	Disagree	Refer to the response to Question 1.
JEA	Disagree	The requirement should simply be that the entity will conduct a Vegetation Inspection at least once per calendar year (per the push for results/performance based requirements). The caveats for natural disasters seem reasonable.
CenterPoint Energy	Disagree	The term “line miles” is not a defined NERC term. The industry terms “structure miles” and “circuit miles” are more common. The NERC Transmission Availability Data System (TADS) utilizes a defined term of “circuit miles” which would be a better choice to avoid confusion and provide the same capability for determining a percent complete status. Transmission Owners are already required to report the number of “circuit miles” of their (greater than or equal to) 200kV transmission line assets annually to TADS.
BC Transmission Corporation	Disagree	The TO's should be required to inspect each line at least once a year. This is critical to eliminating outages and would provide a definite measure for the audit process. The phrase as measured in line miles adds confusion to the requirement. It should state that the applicable lines be inspected along the entire length.
Orange and Rockland Utilities, Inc.	Disagree	There is an inconsistency between R1.2 and R3. R1.2 requires the TO to carry out inspections at least once per calendar year. R3 requires the TO to carry out inspections per the frequency defined in its vegetation management program. It is preferred that the TO be allowed to specify the frequency and timing as stated in R3. Once per calendar year is not sensitive to local and environmental factors. For example, facilities in the Northeast are located in an environment where there is a long (7-8 month) dormant period -vegetation does not grow. Specify a frequency of one inspection per dormant period. This inspection could take place between September and April annually. In one dormant period we might inspect in November and inspect again 14 months later in January. We would meet the inspection need per R3, but fail to have inspected in a calendar year, thus violating R1.2. Other TO’s may be located in parts of the country with little or no vegetation and not need a once per calendar year inspection. Thus, R1.2 should allow the TO to specify an inspection program that is sensitive to local and environmental factors, not the calendar.
Arizona Public Service	Disagree	TO’s should be required to inspected annually. This needs to be in R3 which is stated above. This standard should be consistent so each utility is audited the same.

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp	Disagree	We do not agree with the parenthetical phrase "(as measured in line miles)". Entities may utilize other forms of measurement such as “corridor miles”. The standard should allow the TO to define its own measurement technique and then the VSL for this requirement would be based on a percentage of how much of the TO’s transmission system was missed per the measurement technique defined by the TO. We suggest removing the parenthetical phrase "of all applicable lines (as measured in line miles)" from Req. R3. and add a new subpart of Req. R1 requiring the TO, in its TVMP, to document its method of measuring the applicable lines to be maintained. Corresponding changes to the VSLs are also needed per this proposed revision. The VLS could be revised to read "... inspected greater than x% but less than y% of the Transmission Owner defined measurement technique as defined in sub-part 1.x"
Northern Indiana Public Service Company	Disagree	While I agree with the minimum interval of once a year for vegetation inspections, I have real concerns about using line miles for determining violation severity levels. We conduct vegetation inspections by R.O.W. corridor rather than by circuit or circuit line miles. Multiple circuits or segments of multiple circuits can exisit within the same R.O.W. complicating any calculation of how many line miles are inspected versus not inspected. How about using R.O.W. miles rather than circuit line miles for determining the V.S.L.?
Xcel Energy	Disagree	Xcel Energy does not disagree with the language of R3, however suggests that the referenced footnote 4 be modified to include “species epidemics,” such as bark beetles. It is proposed that footnote 4 have the term “species epidemics” inserted after “landslides” and before “wind shear.”
ISO/RTO Council		The SRC has no comment on this question.

4. As stated in the background information above, in response to industry comments, the Requirement for preventing vegetation encroachments (the new R4) is revised. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 4 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
Arizona Public Service	Agree	
Bonneville Power Administration	Agree	
Central Maine Power an Energy East Company	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
New Brunswick Power Transmission	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery	Agree	
ReliabilityFirst Corporation	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
FirstEnergy Corp	Agree	Although we agree with this requirement, we want to point out a potential concern with double violations between R4 and either R5, R6, R7, or R8. Technically if at any point in real-time you violate one of the requirements R5 through R8, you have also violated R4. The SDT may want to consider adding a clarifying statement in R4 to alleviate a double violation such as "This requirement is not applicable when either R5, R6, R7, or R8 is violated".

Organization	Yes or No	Question 4 Comment
ISO New England Inc.	Agree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by "...as observed in real-time operating between no-load and their Rating."
Orange and Rockland Utilities, Inc.	Agree	ORU agrees that falling vegetation should be an exception to an encroachment but would like clarification to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. ORU is requesting that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation position was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.
PacifiCorp	Agree	PacifiCorp suggests inserting "by a qualified observer" after "observed." Otherwise, utilities could be held accountable to train all their workers who might casually encounter vegetation conditions in their work or commutes.
Southern California Edison Company	Agree	SCE generally agrees with the language of the requirement, but believes that the appropriate Violation Risk Factor is "Lower," rather than "Medium." SCE believes that an encroachment, in and of itself, does not necessarily rise to a level of significance that should require self-reporting, nor should such an occurrence necessarily subject the utility to an investigation with potential adverse findings and penalties. Considering the

Organization	Yes or No	Question 4 Comment
		purpose of the standard and the imprecise nature of vegetation management activities, the standard may be overly strict. Further, due to the resistance of certain land owners and/or agency officials to allowing utilities to prune beyond the prescribed minimum tree-to-line clearances, SCE asks the Drafting Team consider changing the term “Minimum Vegetation Clearance Distances” to “Critical Vegetation Clearance Distances".
Xcel Energy	Disagree	(a) Xcel Energy incorporates its response to number 3 above regarding footnote 4, alternatively, footnote 5 could be modified in a similar fashion to include “species epidemics” between “logging” and “animal severing tree.” (b) Xcel Energy suggests that the phrase “Minimum Vegetation Clearance Distances” (MVCD) be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on the subject property. “Minimum” creates difficulties in explaining to a land owner why any additional clearance need be obtained. That difficulty would be substantially lessened with the use of a term such as “critical,” which more readily lends itself to an additional distance such that the vegetation never approaches the critical distance.(c) Xcel Energy urges the insertion of “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
MRO NERC Standards Review Subcommittee	Disagree	A. The MRO NSRS suggests that the phrase “Minimum Vegetation Clearance Distances” (MVCD) be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on its easements. “Minimum” creates difficulties in explaining to a land owner why any additional clearance needs to be obtained. That difficulty would be substantially lessened with the use of a term such as “critical”, which more readily lends itself to an additional distance such that the vegetation never approaches the critical distance.B. The MRO NSRS agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. As an alternative to the approach in the draft Standard of using footnotes, the MRO NSRS recommends that the SDT consider adding a generic “force majeure” statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here’s an example:Compliance with this standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard.C. R4 states that “Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1........” The MRO NSRS requests the Standard clarify how MVCDs will be interpolated for

Organization	Yes or No	Question 4 Comment
		altitudes not specifically defined in Table 1.
Salt River Project	Disagree	Although the replacement of the Critical Clearance Zone (CCZ) in R4 is an improvement, we still question the use of the Gallet Equation. Although the Gallet Equation is more definitive than using IEEE 516 as identified in the current standard, we question from an engineering perspective as to how and why this method was chosen for vegetation management. The Gallet Equation is a well known method of computing the required strike distance for proper insulation coordination. It is our understanding that the 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, there is no basis for applying this to vegetation management. It is recommended that testing be done to justify this method to be used for vegetation management. 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.
Platte River Power Authority Vegetation Management Group	Disagree	As the requirement is written it is a violation of the requirement when a possible encroachment of the MVCD is discovered through inspections and such an encroachment should be self-reported to the RE. This is inconsistent with the purpose of the standard to prevent vegetation-related outages that can result in Cascading. We would suggest that appropriate action be taken to correct encroachment of the MVCD but that it wouldn’t be a violation of the requirement until a Sustained Outage has occurred or the imminent treat process has been implemented. R4 refers to observation in real-time. This actual field observation of the MVCD between no-load and its Rating is too subjective and lends itself to too much interpretation by the inspector especially in light of the fact that it could be a self-reported violation if the MVCD is encroached.
Associated Electric Cooperative, Inc.	Disagree	Associated Electric Cooperative Inc. suggests the third exception bullet under R4 is unclear. Is the exception meant to address vegetation from either inside or outside the ROW that: 1) may pass through the MVCD while falling; or, 2) has fallen and may now encroach into the MVCD from its new steady state position?
American Transmission Company	Disagree	ATC agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. As an alternative to the approach in the draft Standard of using footnotes, ATC recommends that the SDT consider adding a generic force majeure statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here’s an example:Compliance with this standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing

Organization	Yes or No	Question 4 Comment
		trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard.Also, R 4 states that "Each Transmission Owner shall prevent encroachment of vegetation into the Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2 - Attachment 1........"ATC requests the Standard clarify how MVCDs will be interpolated for altitudes not specifically defined in Table 1.
Consolidated Edison Company of New York Inc.	Disagree	CECONY agrees that falling vegetation should be an exception to an encroachment but would like clarification to confirm that any falling tree that gets lodged into a stable tree and pushes the stable tree beyond the MVCD in real time is also included as part of the falling vegetation exception. CECONY is requesting that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation position was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.
Idaho Power Company	Disagree	Change the Minimum Vegetation Clearance Distance (MVCD) to Critical Vegetation Clearance Distance (CVCD) to indicate a higher level of importance when dealing with federal agencies and reluctant property owners. Provide a better definition for the term 'Real Time'. Include in this definition the use of technology to determine if an imminent threat exists to help minimize real time patrols. In footnote 5 provide more information on what agricultural activities includes.
Vegetation Management Team	Disagree	Disagree with R4 and M4. As explained in the comment for R1, encroachments should also be addressed via a pre-determined process before becoming a violation of the standard. Therefore, we suggest the following changes be made to the requirements: R4: Each Transmission Owner shall [REMOVE: prevent encroachment of vegetation into the] implement its vegetation encroachment response process or procedure when the Transmission Owner has actual knowledge of such an encroachment on any Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2-Attachment 1 [REMOVE: for its applicable lines as observed in real-time operating between no-load and their Rating.], obtained through implementation of the annual work plan and the TVMP. M4: The Transmission Owner has evidence [REMOVE: from inspections that indicate there was no vegetation encroachment into the Minimum Vegetation Clearance Distances listed in FAC-003-2-Attachment 1 for its applicable lines as observed in real-time operating between no-load and their Rating, considering exceptions.] of the implementation of its vegetation encroachment process or procedure showing actions taken and dates of performance.Likewise, we suggest the following be made to

Organization	Yes or No	Question 4 Comment
		the Violation Severity Levels chart: Severe: [REMOVE: The Transmission Owner has failed to prevent vegetation from encroaching into the minimum vegetation clearance distance.] The Transmission Owner did not implement its vegetation encroachment response process or procedure when the Transmission Owner had actual knowledge of such an encroachment on any Minimum Vegetation Clearance Distances (MVCD) listed in FAC-003-2-Attachment 1 obtained through normal operating practices.
Hydro-Quebec TransEnergie (HQT)	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
Independent Electricity System Operator	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
Northeast Power Coordinating Council--RSC	Disagree	Falling vegetation should be an exception to an encroachment but a clarification is needed to confirm that any falling tree that gets lodged into another tree and violates the MVCD in real time is also included as part of the falling vegetation exception. Also, if a line is operating beyond its Emergency Rating due to system

Organization	Yes or No	Question 4 Comment
		conditions, encroachments of the MVCD should not be considered a violation of R6. Request that additional clarification be made between the relationship of R1.6 and R4. R1.6 is a documentation requirement that requires that the TVMP specify strategies to ensure that the MVCD clearances are never violated under all operating/rated conditions. R4 is an implementation requirement that makes it a violation to encroach upon the MVCD in real time only. So if we had a situation where there would have been an MVCD encroachment if the conductor was at its lowest position (maximum sag) but, at the time of the observation, the conductor was at a higher position (not at maximum sag), our understanding is that there would be no violation of either R1.6 or R4 since the real time observation determined that the vegetation clearance was greater than the MVCD. This assumes that the strategies required under R1.6 are included in the TVMP.Clarification is needed for what is meant by “...as observed in real-time operating between no-load and their Rating.”
JEA	Disagree	I object to the zero defect concept. I realize that there is pressure from FERC, however Section 215 of the FPA specifically states "The Commission shall give due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard..." The technical feasibility of 0 defects is questionable. The industry should develop an aggressive but acheivable performance level for preventing encroachments etc.
CenterPoint Energy	Disagree	It is not clear how R4’s last bullet, “Encroachment into the MVCD listed in FAC-003-2-Attachment 1 resulting from falling vegetation” is observable as an exception, and the Technical Reference does not clarify it either. It would appear that if a tree branch (e.g. wind-blown or fallen branch debris) was observed hanging on the conductor, but was not causing an outage, that it would be considered an exception. The bullet item should be clarified or deleted.
US Bureau of Reclamation	Disagree	It is not clear why wind blown debris is not listed as an exception. It is also not clear why these exemptions are needed as they are not vegeetation encroachments.
North Carolina Electric Membership Corporation	Disagree	NCEMC has concerns about the enforcement of the requirement.There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards, xmas tree farms, community tree plantings, etc.) from the standard and will invite legal challenges to the TO’s right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new

Organization	Yes or No	Question 4 Comment
		plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Public Service Co. of New Mexico	Disagree	PNM is not in favor of the current MVCD table 1. This will not provide clarity to the field personnel as to clearance distances. It could cause increasing confusion as to how much clearance needs to be obtained at the time of work. Clearance 1 and 2 were much clearer in that respect.
SCE&G	Disagree	SCE&G has concerns about the enforcement of the requirement. There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Duke Energy	Disagree	Since this standard already includes other requirements to implement a transmission vegetation management program to maintain the defined clearances, as well as an imminent threat process or procedure to avoid sustained outages, we believe that Requirement R4 provides no additional reliability benefit and should be deleted. If it is decided that this requirement must be retained, then it needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. Such a zero-tolerance approach to preventing encroachments does not provide industry with a reasonable opportunity for success, absent the establishment of overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement should be structured for a graduated VSL. Due to this requirement being focused on preventing encroachments rather than sustained outages, we believe that a zero tolerance approach is not warranted to improve reliability.In addition, the third exemption is not clear as it relates to falling vegetation. For example, how would an event be viewed if a tree lodges into another tree or hits another tree causing it to lean such that it is within the MVCD?
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	The definition of Rating includes the word -limits- implying that Rating is a plural term. Does the SDT mean the highest sustained limit (10 minutes? 30 minutes? 24 hours?...)?
Manitoba Hydro	Disagree	The phrase “Minimum Vegetation Clearance Distances” (MVCD) should be changed to “Critical Clearance Distance.” The use of the word “minimum” creates problems for Transmission Owners when dealing with land owners regarding the necessary vegetation management which is to take place on the subject property. “Minimum” creates difficulties in explaining to a land owner why any additional clearance need be obtained. That difficulty would be substantially lessened with the use of a term such as “critical,” which more readily

Organization	Yes or No	Question 4 Comment
		lends itself to an additional distance such that the vegetation never approaches the critical distance.Insert “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
E.ON U.S.	Disagree	The standard does not specify what is meant by “off/on ROW”.E.ON U.S. questions how NERC plans on enforcing the third bullet
BC Transmission Corporation	Disagree	The standard should limit itself to the prevention of outages. If vegetation encroaches within the MVCD and the TO effectively implements the imminent threat process to prevent an outage this should not be a violation. Additionally this requirement will be very difficult to audit and enforce.
Puget Sound Energy	Disagree	The term, Minimum Vegetation Clearance Distance (MVCD) does not invoke the critical dangerous nature of the close distance to the conductor. A more impactful term such as “critical” would be more appropriate.
Ameren	Disagree	The third bullet point on "falling vegetation" is unclear. Would like to see this clarify whether on ROW and/or off ROW falling trees.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	The VMS has concerns about the enforcement of the requirement.There seems to be an issue with enforcement of the third exemption if any vegetation falls and lodges to create a MVCD violation from inside or outside the ROW.
Progress Energy Carolinas, Inc.	Disagree	There is an issue with the wording of the third exemption when any vegetation from outside the ROW falls and lodges to create a MVCD violation. The wording as proposed could be interpreted as non-compliance due to vegetation from outside of the ROW.
Entergy Services, Inc	Disagree	There may be an issue of the third exemption if vegetation falls and lodges to create a MVCD violation from inside or outside the Right of Way.
Tucson Electric Power Company	Disagree	We feel that the use of the word “Minimum” in Minimum Vegetation Clearance Distance should be “Critical”. Governing/Managing land agencies could use the word Minimum, as an allowable limit argument against the utility and deny needed permissions work as long as there is more than the minimum clearance in on the line. The use of the word critical would indicate the need for additional buffer distance to prevent vegetation caused outages. Additionally is the exception to the rule about falling vegetation from inside or outside the ROW/Easement?

Organization	Yes or No	Question 4 Comment
Nebraska Public Power District	Disagree	Xcel Energy urges the insertion of “by a qualified observer” after “observed.” Otherwise, a Transmission Owner could have a violation as a result of a drive-by glance by an office clerical worker.
ISO/RTO Council		The SRC has no comment on this question.

5. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on IROL or Major WECC Transfer Paths (the new R5) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 5 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	

Organization	Yes or No	Question 5 Comment
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
PacifiCorp	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New	Agree	

Organization	Yes or No	Question 5 Comment
Mexico		
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	

Organization	Yes or No	Question 5 Comment
Orange and Rockland Utilities, Inc.	Agree	ORU agrees that, if a line is operating beyond its Emergency Rating due to system conditions, encroachments of the MVCD should not be considered a violation of R5.
Southern California Edison Company	Agree	SCE generally agrees with the assigned Violation Risk Factor for lines that are an element of an IROL or a WECC transfer path. SCE believes that the bulleted exceptions listed in the new R5 are appropriate.
Tampa Electric Company	Agree	The white paper, on page 33, paragraph 4, defines a sustained outage as vegetation related event, if it occurs within the specified rating of the facility. If the conductor is operating above its rating it states that this “would not be classified as a vegetation related sustained outage under the standard.” If this is so it needs to be stated and/or clarified in the standard itself.
American Transmission Company	Disagree	ATC recommends that the SDT consider the statements in the Technical Paper on pgs. 32-34; i.e. encroachment taking place while a line is operating beyond its rating is not a violation of this Requirement.
FirstEnergy Corp	Disagree	FE suggests a revision of Requirement R5.FE encourages the team to re-evaluate its approach to requirements R5 through R7 and consider changes that would remove the binary aspect of the requirements and permit a graded approach to the VSL structure for a non-compliance of the requirement. Our proposal is to incorporate aspects of R7 (blow in) and R8 (fall in) into both requirements R5 (grow-in IROL) and R6 (grow-in Non-IROL) so that R5 and R6 establish requirements for grow-in, blow-in and fall-in. The proposed requirement for R5 would read: "Each Transmission Owner shall prevent Sustained Outages of applicable lines that are identified as an element of an Interconnection Reliability Operating Limit (IROL) (or Major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, due to the blowing together of a conductor and vegetation rooted within an ActiveTransmission Line Right of Way (operating within design blow-out conditions), or due to vegetation falling into a conductor with the following exceptions:"Similarly, the proposed R6 would read:"Each Transmission Owner shall prevent Sustained Outages of applicable lines that are not an element of an IROL (or major WECC Transfer Path) due to vegetation growing into a conductor operating between no-load and its Rating, due to the blowing together of a conductor and vegetation rooted within an Active Transmission Line Right of Way (operating within design blow-out conditions), or due to vegetation falling into a conductor with the following exceptions:"These requirement changes provide the flexibility needed to establish graded VSLs. FE’s proposed VSL levels are consistent with the reporting categories established in section D 1.5. The root of the requirement is "shall prevent Sustained Outages" and the VSL gauge of how much a VM program missed the mark would then be reflected in the type of vegetation contact. Therefore, we propose VSL levels for both Req. R5 and R6 as follows: grow-in (SEVERE VSL), a fall-in (MODERATE VSL),a blow-in (LOWER VSL).No changes to the Violation Risk Factors or Time Horizons for requirements R5 or R6 are proposed.If the proposal is accepted, conforming changes to the Measures are required.

Organization	Yes or No	Question 5 Comment
WECC	Disagree	I agree with the requiring the prevention of sustained outages due to grow-ins on an identified subsed of all transmission facilities. However, I am concerned over the use of the capitalized term Major WECC Transfer Paths. Because this is not a defined term in the NERC Glossary and is not the complete name of any WECC listing,I suggest the phrase (or Major WECC Transfer Paths)be changed to (or major transfer paths in the Western Interconnection as identified by WECC). In the alternative, the full name of the dcoument known as Table 2 that is referred to in the second draft is "Major WECC Transfer Paths in the Bulk Electric System". Is there going to be a problem with the capitalized term if a definition is not developed, knowing that the capitalized term refers to an existing document?
Tucson Electric Power Company	Disagree	In the footnote examples of human activities, there is an exemption for agricultural activities. The planting of and maintenance of orchards is an agricultural activity that should specifically address as not applying in this exemption.
US Bureau of Reclamation	Disagree	It is not clear what Natural disasters or human activity have to do with growing vegetation. Also it is not clear why falling vegetation or wind blown debris are not listed as exemptions.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO's right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	R5 also uses the term Rating. See comment to Q4.
Puget Sound Energy	Disagree	Regional differences should be addressed through regional standards. The reference to Major WECC Transfer Paths should be removed and allow the region to determine whether to expand the implication of the standard.

Organization	Yes or No	Question 5 Comment
Hydro-Quebec TransEnergie (HQT)	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional “drilling down” is not needed. R5 and R6 seems to have been introduced just to have different violation risk factor for different types of lines. Delete R5 or R6 after removing the IROL concept.
Independent Electricity System Operator	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional “drilling down” is not needed.
ISO New England Inc.	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional “drilling down” is not needed.
Northeast Power Coordinating Council--RSC	Disagree	The introduction of IROL introduces an unnecessary level of complexity in the standard. The facilities being addressed in the standard impact the Bulk Electric System, and the additional “drilling down” is not needed.
BC Transmission Corporation	Disagree	The IROL is not properly defined in this standard it is hard to agree with this requirement if we do not know exactly what this means. Please put foot note #7 back into the document. Why single out WECC and not other reliability councils.
Manitoba Hydro	Disagree	The SDT should consider the statements in the Technical Paper on pgs. 32-34 that encroachment taking place if a line is operating beyond its rating would not be a violation of the Requirement.
ISO/RTO Council		The SRC has no comment on this question.

6. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to grow-ins on non-IROL or Major WECC Transfer Paths (the new R6) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 6 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	

Organization	Yes or No	Question 6 Comment
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
PacifiCorp	Agree	

Organization	Yes or No	Question 6 Comment
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	

Organization	Yes or No	Question 6 Comment
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
ReliabilityFirst Corporation	Agree	Do we need R5 and R6? The requirements are same whether the line is an IROL or not.
ISO New England Inc.	Agree	Refer to the response to Question 5.
Tampa Electric Company	Agree	Same response as question 5.
Southern California Edison Company	Agree	SCE generally agrees with the assigned Violation Risk Factor for lines that are not an element of an IROL or a WECC transfer path. SCE believes that the bulleted exceptions listed in the new R6 are appropriate.
American Transmission Company	Disagree	ATC recommends that the SDT consider the statements in the Technical Paper on pgs. 32-34; i.e. encroachment taking place while a line is operating beyond its rating is not a violation of this Requirement.
FirstEnergy Corp	Disagree	FE suggests a revision of R6. See our response to Question 5 for further information.
US Bureau of Reclamation	Disagree	It is not clear what Natural disasters or wind blown debris have to do with growing vegetation. Also it is not clear why human or animal activity or falling vegetation are not listed as exceptions.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO's right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have

Organization	Yes or No	Question 6 Comment
		actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
Independent Electricity System Operator	Disagree	Refer to the response to Question 5.
Northeast Power Coordinating Council--RSC	Disagree	Refer to the response to Question 5.
WECC	Disagree	same comment as for question 5. Agree with the concept, but concern over the term major WECC Transfer Paths (note that the word major is not capitalized in R6 but it is in R5. Suggest replaceing with the phrase (or major transfer paths in the Western Interconnection as identified by WECC)
Hydro-Quebec TransEnergie (HQT)	Disagree	See answer to Q5.
Manitoba Hydro	Disagree	The SDT should consider the statements in the Technical Paper on pgs. 32-34 that encroachment taking place if a line is operating beyond its rating would not be a violation of the Requirement.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

7. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to blowing together of vegetation and transmission line conductors (the new R7) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 7 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	

Organization	Yes or No	Question 7 Comment
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	

Organization	Yes or No	Question 7 Comment
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Vegetation Management Team	Agree	Concerned about the term “design blow-out conditions”. Some natural disasters (hurricanes, wind shear, fresh gale, etc.) may have a lower threshold than “design blow-out.

Organization	Yes or No	Question 7 Comment
Northern Indiana Public Service Company	Agree	Have concerns about T.O.'s determining what is "active" and "inactive" R.O.W. which are explained in Question 1 comments.
Southern California Edison Company	Agree	SCE generally agrees with the content of the new R7, but believes it could be combined with the new R8 into a single requirement (a revised new R7). It appears to SCE that both bulleted exceptions listed in the new R8 can also be applied to the new R7. Please see SCE's response to Question 8 below.
E.ON U.S.	Disagree	: E.ON U.S. requests that the SDT add language specifically excluding vegetation outside of an active ROW that could potentially blow into the conductor
North Carolina Electric Membership Corporation	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
SCE&G	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	An issue exists, as currently worded, in that it does not exclude vegetation entirely off the ROW, under normal weather conditions, that could be blown into the conductor.
Entergy Services, Inc	Disagree	As currently written, the Standard does not exclude vegetation entirely off the Right of Way, under normal weather conditions, that could be blown into the conductor.
Associated Electric Cooperative, Inc.	Disagree	Associated Electric Cooperative Inc agrees with the intent of R7. Perhaps the clarity could be improved by rewording, such as: “Each Transmission Owner shall prevent Sustained Outages6 of applicable lines due to the blowing together of a conductor and vegetation from within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception: [Violation Risk Factor - Medium][Time Horizon - Real Time]o Sustained Outages of applicable lines that result from natural disasters4 or wind-blown debris.
American Transmission Company	Disagree	ATC requests the SDT to clarify “wind-blown debris”. ATC believes the definition should include branches and/or trunks partially severed from the tree.
FirstEnergy Corp	Disagree	FE suggests a removal of R7. See our response to Question 5 for further information.
Tampa Electric Company	Disagree	In the white paper, page 35, paragraph 2, it states that if the conductor is operating above its rating it” would

Organization	Yes or No	Question 7 Comment
		not be classified as vegetation related sustained outage under the standard." If this is so it needs to be stated and/or clarified in the standard itself. In addition, on page 35, 3rd paragraph, last sentence of the white paper it states," Additionally, sustained outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from this standard." Again if this is so it needs to be stated in the standard. Question for clarification: If the debris that falls is from a tree within the active transmission line ROW is it a violation?
US Bureau of Reclamation	Disagree	It is not clear why Natural disasters or wind blown debris have to do with vegetation blowing together with transmission lines. Also it is not clear why human or animal activity or falling vegetation are not listed as exemptions.
Central Maine Power an Energy East Company	Disagree	Note that R7 applies only to trees growing within the active right of way. Suggest that the standard clearly explain this concept.
Progress Energy Carolinas, Inc.	Disagree	Off ROW vegetation blowing into conductors is nothing more than off ROW vegetation "falling into the line" without permanent deformation of the vegetation (i.e., breaking/uprooting). Since the original design of the line did not require the off ROW vegetation to be removed, off ROW vegetation should not be included in the requirement.R8 as it is currently worded, "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor within an Active Transmission Line Right of Way (operating within design blow-out conditions) with the following exception:" should be reworded as follows... "...due to the blowing together of a conductor and vegetation rooted within the Active Transmission Line Right of Way...)
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
CenterPoint Energy	Disagree	R7 refers to "Active Transmission Line Right of Way" which is not defined as to its limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the "...Transmission Owner is responsible for defining the Active Transmission Line Right of Way." However, that defining clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase, "within an Active Transmission Line Right of Way", deleting the phrase, "operating within design blow-out conditions", and revising R7 to read, "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor operating within its designed sway under rated conditions with the following exceptions...". The terms used in R1 of "sag" and "sway" should be used consistently. R1.6 already requires that maintenance strategies ensure that the MVCD is never violated

Organization	Yes or No	Question 7 Comment
		and "consider the sag and sway of the conductor throughout is operating range and under rated conditions". This requirement by itself defines the airspace that must be maintained to prevent a Sustained Outage. R7 requires no specific definition of a right of way because R1 already defines the necessary minimum clearance to be maintained at all times.
Transmission Owner	Disagree	This requirement is not congruent with the purpose of this standard. The standard was enacted as a result of the North East Blackout and a history of grid blackouts in which the growth of trees below conductors under load contributed to the situation. Trees blowing into the conductor create no more risk to cascading than causes such as lightning or foreign interference. This requirement should be removed from the standard.
Arizona Public Service	Disagree	This requirement is too vague and needs more clarity. Vegetation in the easement width or permitted ROW shall not blow into the conductors resulting in an outage. If a utility has rights to maintain vegetation there shouldn't be any outages due to vegetation from blowing into the conductors. There active ROW should be wide enough to prevent these types of outages.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be "Severe". This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

8. As stated in the background information above, in response to industry comments, the Requirement for preventing Sustained Outages due to fall-ins of vegetation (the new R8) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 8 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
Bonneville Power Administration	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System	Agree	

Organization	Yes or No	Question 8 Comment
Operator		
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority	Agree	

Organization	Yes or No	Question 8 Comment
Vegetation Management Group		
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 8 Comment
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Central Maine Power an Energy East Company	Agree	Active right of way is an important component to R8.
Northern Indiana Public Service Company	Agree	Have concerns about T.O.'s determining what is "active" and "inactive" R.O.W. which are explained in Question 1 comments.
Southern California Edison Company	Agree	SCE agrees with the content of the new R8, but believes that R8 should be combined with the new R7 into a single requirement (a revised new R7). It appears to SCE that both bulleted exceptions listed in new R8 can be applied to a revised new R7 which would then read: NEW R7. Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor, or, vegetation falling into a conductor from within an Active Transmission Line Right of Way, with the following exceptions: [Violation Risk Factor - Medium] [Time Horizon - Real Time]o Sustained Outages of applicable lines that result from natural disasters or wind-blown debris.o Sustained Outages of applicable lines that result from human or animal activity.
Tampa Electric Company	Agree	The white paper again states that the conductor is operating within its normal rating. If, when it is operating above its normal rating it is not classified as a vegetation related outage under the Standard, this needs to be clarified in the standard itself.
Arizona Public Service	Disagree	APS understand the concept of active ROW but the SDT needs to clarify trees within the easement or permitted ROW and those outside the ROW. Utilities have a responsibility to maintain those within and shall be held accountable.
American Transmission Company	Disagree	ATC requests the SDT to clarify whether this includes branches partially severed from the tree falling into a conductor from within the active ROW.
FirstEnergy Corp	Disagree	FE suggests a removal of R8. See our response to Question 5 for further information.

Organization	Yes or No	Question 8 Comment
BC Transmission Corporation	Disagree	I strongly recommend that this be changed from “shall prevent sustained outages” to “shall minimize sustained outages due to fall ins. 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.
US Bureau of Reclamation	Disagree	It is not clear why Natural disasters or human or animal activity or wind blown debris have to do with vegetation fall-ins and why they would need to be exempted.
PacifiCorp	Disagree	PacifiCorp suggests inserting “by a qualified observer” after “observed.” Otherwise, utilities could be held accountable to train all their workers who might casually encounter vegetation conditions in their work or commutes.
Pacific Gas and Electric Co.	Disagree	PG&E agrees in principal with R5 but disagrees with the exception for human activity noted in footnote (5), specifically aboriculture, horticulture or agricultural activities. This exception is overly broad and could be interpreted as exempting certian activities (such as planting orchards) from the standard and will invite legal challenges to the TO’s right to perform vegetation management. PG&E proposes alternative language to the exception as follows: Examples include, but are not limited to, logging, animal severing tree, vehicle contact with tree, digging or removal of tree or new plantings between inspection cycles where the TO does not have actual knowledge. As an alternative, add a generic force majeure statement as described in Q18 #2.
Xcel Energy	Disagree	Please see our comments above concerning footnotes 4 & 5.
JEA	Disagree	Please see the comment to question 4.
CenterPoint Energy	Disagree	R8 refers to “Active Transmission Line Right of Way” which is not defined as to its limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the “...Transmission Owner is responsible for defining the Active Transmission Line Right of Way.” However, that defining clause is not included in the current definition. CenterPoint Energy recommends deleting the phrase, “within an Active Transmission Line Right of Way”, and revising R8 to read, “Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor where the Transmission Owner had the legal right or prior permission to remove the vegetation.”Since R1 in the Standard does not address how a Transmission Owner conducts its work to address the fall-in of trees into an adjacent transmission line, R8 may not be needed in the Standard. In the Technical Reference under the Applicability of the Standard, the SDT states that “On the other hand, most other outage causes (such as

Organization	Yes or No	Question 8 Comment
		trees falling into lines....) are statistically intermittent. The probability of occurrence of these events is not dependent on heavy loads. There is no cause-effect relationship which creates the probability of simultaneous occurrence of other such events. Therefore these types of events are highly unlikely to cause large-scale grid failures.” This observation made by the SDT would support the removal of R8 from the Standard. R8 appears to be a major driving cause for introducing the new term “Active Transmission Line Right of Way”, and removing R8 would avoid the need to introduce this ambiguously defined term and simplify the Standard without significant impact on its intended purpose. The impact of R8 is also diminished by the fact that the majority of fall-ins occur as a result of the exceptions currently stated in the rule and are typically from outside the maintained boundary of the right of way.
E.ON U.S.	Disagree	The standard must be consistent with R4
Transmission Owner	Disagree	This requirement is not congruent with the purpose of this standard. The standard was enacted as a result of the North East Blackout and a history of grid blackouts in which the growth of trees below conductors under load contributed to the situation. Trees falling into the conductor create no more risk to cascading than causes such as lightning or foreign interference. This requirement should be removed from the standard.
Duke Energy	Disagree	This requirement needs to be re-written such that it is a performance-based requirement with graduated VSLs. As currently written, this requirement is a binary requirement which carries a single VSL which can only be “Severe”. This may drive overly-aggressive and costly vegetation management programs that carry minimal additional reliability benefit. A performance-based requirement should be developed relative to some metric such as line-mile exposure that will promote high quality vegetation management, optimization of the reliability cost/benefit relationship and deliver the overall end result of improved reliability to the system. The performance-based requirement may still be zero tolerance, but should be structured for a graduated VSL.
ISO/RTO Council		The SRC has no comment on this question.

9. As stated in the background information above, in response to industry comments, the Requirement for implementation of annual work plan (the new R9) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 9 Comment
Entegra Power Group LLC		No comment
Ameren	Agree	
American Electric Power	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	

Organization	Yes or No	Question 9 Comment
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
National Grid	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Orange and Rockland Utilities,	Agree	

Organization	Yes or No	Question 9 Comment
Inc.		
Pacific Gas and Electric Co.	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	

Organization	Yes or No	Question 9 Comment
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Southern California Edison Company	Agree	SCE agrees with the content of the new R9, however, we suggest it be placed immediately after R1 and be identified as the new R2. SCE suggests that the requirement be modified to read: R9(R2). Each Transmission Owner shall implement its annual work plan for VegetationManagement.
Oncor Electric Delivery	Disagree	Comments: See response to Q.1 The VSL for R9 indicate “failure to implement” percentages of the annual work plan for the different VSL levels. There is lack of clarity in how “percentage” is defined. Is percentage based on 1) # of lines in the annual plan vs # lines not worked according to the annual plan or 2) miles of line not implemented vs total miles in the annual plan?
Platte River Power Authority Vegetation Management Group	Disagree	It seems apparent that if you have a work plan (R1.3.) you should implement that plan and M9 specifies the evidence of such implementation is specific to the work plan. However, the requirement is ambiguous as we interpret it to apply only to the work plan as outlined in R1.3. but the last sentence "...to accomplish the purpose of this standard" makes us wonder if perhaps the implementation and documentation required is boarder. We understand that the implementation of the work plan is separated into a separate requirement so that different VRF and VSL can be assigned but it would provide more clarity if the requirement were as follows: R9. Each Transmission Owner shall implement and document its annual work plan for vegetation management to meet R1.3. In cases when the annual work plan is adjusted or not completely implemented as originally planned, the reasons for the deferrals or changes and the expected completion date of the postponed work should be documented as well.

Organization	Yes or No	Question 9 Comment
Nebraska Public Power District	Disagree	NPPD agrees with the wording provided by Xcel Energy. Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard, subject to its legal rights.
Central Maine Power an Energy East Company	Disagree	Restore the phrase " within the extent of its easement and/or legal rights" found in FAC 003 1 .
Idaho Power Company	Disagree	Reword R9 to say ‘The TO shall implement its annual work plan for vegetation management within its legal rights...’
American Transmission Company	Disagree	Same response as in Question # 1 (addressing R1.3 and R1. 5) ATC believes that Requirement 9 should allow for flexibility in the annual work plan to carry over implementation to the following calendar year.
Manitoba Hydro	Disagree	The annual work plan should allow for justification to carry over the implementation to the following calendar year or years.
PacifiCorp	Disagree	The current language of the requirement places the sole burden for implementation of the annual work plan, including the correction timeframe, on the Transmission Owner. This could be problematic on federal property where local district offices have authority over whether or not to approve vegetation management work. In order to implement their annual work plans, Transmission Owners must obtain approval from any applicable federal agency through that agency’s approval process. There are occasions where authorization from that agency may take many months or even years. The language of the requirement should be modified to take this into account; if authorization from the applicable federal agency is not granted within six months, the Transmission Owner should not be subject to penalties or sanctions because these would be associated with actions beyond their control.
Arizona Public Service	Disagree	There should be a footnote that if federal or state agencies fail to approve annual work plans within 90 days of submittal the utility will not be held accountable for not completing its annual work plan or taking into account the time it takes to get approval. We have land agencies that give us approvals within 2 weeks and others that have taken over a year. Utilities are at their mercy on the approval process. If there is turn-over in the land agency the approval process changes again and it is impossible to determine the anticipated timeline by state, tribal and federal agencies.
Salt River Project	Disagree	There should be an additional statement to include “subject to the Transmission Owner’s legal rights”. This requirement should acknowledge the difficulties Transmission Owner’s have working with federal and state

Organization	Yes or No	Question 9 Comment
		agencies that do not approve work plans in a timely manner.
FirstEnergy Corp	Disagree	We agree with this requirement except for the phrase "to accomplish the purpose of this standard". This phrase is unnecessary and could lead to unintended interpretations. It is understood that every requirement in each reliability standard is written to accomplish the purpose of its respective standard, and those words should not be required in the text of the requirements.
Xcel Energy	Disagree	Xcel Energy strongly believes that the requirement that each Transmission Owner shall implement its annual work plan for vegetation management must acknowledge that such vegetation management is subject to the legal rights available to the Transmission Owner. Hence, it is suggested that R9 be revised to read: "Each Transmission Owner shall implement its annual work plan for vegetation management to accomplish the purpose of this standard, subject to its legal rights."
ISO/RTO Council		The SRC has no comment on this question.

10. As stated in the background information above, in response to industry comments, the Requirement for the preparation of list for sub 200kV transmission lines by the Planning Coordinator (the new R10) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 10 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 10 Comment
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	

Organization	Yes or No	Question 10 Comment
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	

Organization	Yes or No	Question 10 Comment
TVA	Agree	
TVA	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Superintendent Transmission Maintenance	Agree	Agree with the requirements under R10, however, request further clarification on the source and qualifications of the "Planning Coordinator".
Edison Electric Institute	Agree	First, EEI generally agrees with the draft revised applicability section. In addition and to help reduce ambiguity in the text, EEI asks that the SDT consider additional language in R.10 and R. 11 (and M. 10 and M. 11) that Planning Coordinators be required to include all facilities under 200 kv identified as IROL facilities under FAC-014. For example, the language of the applicability of the Standard could be stated to include all facilities under 200 kv identified under FAC-014 as IROL facilities. The corresponding requirement could be stated as ‘Each Planning Coordinator will notify all Registered Entities under 200 kv for which this Reliability Standard applies.’ EEI also believes that this change would be consistent with the discussion of the issue in Order No. 693 (P. 706)Second, EEI recommends consideration for including in the applicability section of the Standard the phrase from the technical paper, i.e., the Standard will not apply to line sections inside the electric station fence or other boundary of an electric station, or underground lines. (Technical Paper, p. 8) If included, this addition would add much-needed clarity for Registered Entities.In particular, EEI encourages further consideration for lines from generation facilities to network substations. Some Generation Owners have lines greater than a mile in length EEI asks the SDT consider whether to extend applicability of the Standard for Generation Owners that own lines that meeting certain predefined criteria, or other approaches that would clarify the treatment of lines owned by Generation Owners on the generator side of a network substation. Finally, further clarification may be needed on whether the Standard will cover all facilities rated at greater than 200 kv. For example, there may be 230 kv radial lines to distribution deemed exempt from a BPS -defined set of assets. EEI understands that some confusion exists on whether the threshold BPS

Organization	Yes or No	Question 10 Comment
		definition governs applicability for all individual Standards.
Southern California Edison Company	Agree	SCE generally agrees with the requirement, but is concerned about the new role for the Planning Coordinator and the posibility that it will have shared compliance responsibilities for designated lines with the Transmission Owner.
Hydro-Quebec TransEnergie (HQT)	Disagree	NERC standards apply only to BES facilities and not necessarily at voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. The only change between the current standard and the proposed draft is who designates critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.Furthermore, the purpose of the standard should be changed to read : 'To improve the reliability of the Bulk Electric System by preventing....' since the NERC Standards are designed to be applicable to the BES, not the 'electric transmission system'; or is it the real intention of NERC to have some standards for BES and some for 'electric transmission system'? We would appreciate to have the SDT opinion on this.
Independent Electricity System Operator	Disagree	NERC standards apply only to BES facilities, and not necessarily a voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.
Northeast Power Coordinating Council--RSC	Disagree	NERC standards apply only to BES facilities, and not necessarily a voltage level threshold. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.

Organization	Yes or No	Question 10 Comment
ISO New England Inc.	Disagree	NERC standards apply only to BES facilities. The standards should not apply to facilities that are not BES. Within a standard there might be exceptions for cases where the standard would apply only to a subset of the BES facilities. This is the case of the FAC-003 current standard and the new draft which both state that the standard applies only to transmission lines operated at 200 kV and above, and to any lower voltage lines designated as critical to the reliability of the electric system in the region. The only change between the current standard and the proposed draft is who designates the above critical lines. In the current standard it was the RRO while in the new standard it is the PC. The RRO (or the PC in the future version) can only designate critical lines among those that are already classified as BES.
Public Service Co. of New Mexico	Disagree	PNM disagrees with the use of the "Planning Coordinator." There is no definition of this individual or group of individuals anywhere in the proposed standard or white paper that is apparent. Clarification is needed.
MRO NERC Standards Review Subcommittee	Disagree	R10 states that the PC “consult” with its TOs and neighboring PCs to obtain input for the list of qualifying facilities operated below 200 kV. What does “consult” mean? It is a surrogate for “coordinate” which is being removed from standards because of compliance implications - an entity might be held in violation if another entity did not respond or act to “coordinate” the effort. Also, R11 uses the terms “reliability significance” and “unacceptable risk of instability” which are undefined and not measurable. R11 is the lead requirement and could be moved to new R1 location. Better wording would be “Each PC must develop and document a methodology for determining a list of facilities in its area operated at less than 200 kV whose loss would cause instability, separation or cascading failures on the BES. “ R10 follows directly and would become new R2. Better wording would be “Each PC shall prepare and review annually a list of facilities in its area operated at less than 200 kV which are subject to this standard. This list will be based on information obtained from its TOs. Results will be provided to its TOs and neighboring PCs.”
American Transmission Company	Disagree	See response to Question #11 below.
Platte River Power Authority Vegetation Management Group	Disagree	The requirement is confusing as it infers that it relates to R11 but never states such. It might be clearer if it followed R11, as we believe the correct process should be as stated in the FAC-003-2 Technical Reference: "Planning Coordinators, using their methodologies described in R11, will need to conduct the necessary studies and identify candidate sub-200kV transmission lines for potential applicability under the Standard. The Planning Coordinators will next need to consult with its Transmission Owners and neighboring Planning Coordinators to resolve any differences in the selection of the sub-200kV transmission lines of common interest. Finally, the Planning Coordinator will need to finalize, adopt and issue the list of designated sub-200kV lines". The way it is currently written the Planning Coordinator will need to finalize, adopt and issue the list of designated sub-200kV lines first then consult with its Transmission Operators and neighboring Planning

Organization	Yes or No	Question 10 Comment
		Coordinators and last develop a methodology. We aren't sure why R10 and R11 are separate requirements as they seem to be related and both have the same VRF and time horizon. We believe the two requirements should be combined and placed in sequential order.
US Bureau of Reclamation	Disagree	The role of the Planning Coordinator is inappropriately described in this requirement. The role of the Planning Coordinator as related in the NERC Functional Model is to conduct assessments of transmisssion systems. Planning Coordinators do not implement resource plans (NERC Functional Model Technical Document Page 12 last paragraph). The determination of criticality is an implementation action or operational determination which is reserved for either the Transmission Planner or the Reliability Coordinator. The role of the Planning coordinator is to develop methodologies which are used by others in ensuring reliable BES operation. Specifically the "Planning Coordinator coordinates and evaluates and recommends reinforcement and corrective plans resulting from studies and analysis of system performance and interconnection of facilities." To require the Planning Coordinator to prepare a list of lines which are subject to this standard (critical to the BES) is modifying the role of the Planning Coordinator and should be examined in the context of the role of the Transmission Operator, Transmission Owner, Transmission Planner and Reliability Cooridnator under a separate project.
FirstEnergy Corp	Disagree	We suggest the team consider changes to R10 and R11 to ensure consistency with standard FAC-014 for the transmission facilities that are sub-200kV and deemed as having "reliability significance" and placing the grid at risk for instability and Cascading. FE believes the appropriate set of sub-200kV lines are those identified as being associated with an IROL condition. Utilizing an already established IROL methodology (FAC-010 and FAC-014) eliminates the need for the Planning Coordinator to coordinate with the Transmission Owner(s) alleviating a level of tedious compliance evidence for the Planning Coordinator. Finally, presently missing within the requirement is the need for the Planning Coordinator to submit a list of the reliability significant sub-200kV facilities to the Transmission Owner(s).We propose that requirements R10 and R11 be replace with a single new R10 requirement as follows:"R10 Each Planning Coordinator shall prepare and review annually, a list of lines thatare operated below 200kV, if any, which are subject to this standard. 10.1 The list shall reflect sub-200kV transmission facilities associated with an IROL condition as identified per NERC reliability standard FAC-014. 10.2 The Planning Coordinator shall annually notify its Transmission Owner(s) of the sub-200kV reliability significant facilities that are subject to this standard."No changes to the Violation Risk Factors or Time Horizons for the proposed requirement. We support a VRF of Lower and Time-Horizon of Long-Term Planning.If the proposal is accepted, conforming changes to the Measures are required.Lastly, the team should consider asking NERC to add to its Standards Development issues database a need to revise standard FAC-014 such that the Transmission Owner is notified of all IROL transmission facilities as part of FAC-014. This would allow for changes in FAC-003 that could eliminate the Planning Coordinator as being applicable to the FAC-003 standard.

Organization	Yes or No	Question 10 Comment
ISO/RTO Council	Disagree	We reiterate our comments submitted for Version 1 that the Planning Coordinators and Reliability Coordinators do not have a role in this standard, and requirements R10 and R11 are not needed. Facilities below 200KV are generally not critical on a wide area basis. There may be some facilities that are critical for local service – most likely in metropolitan areas or a very rural system where they are wholly dependent on sub 200KV facilities. Therefore, there is not a need for a wide area assessment by the Planning Coordinator in this standard. Those facilities below 200KV that are vital for local service would already be identified and included in the vegetation management program of the Transmission Owner. Further, facilities that are associated with IROLs, regardless of voltage class, are already identified through the R5 requirements. We understand the SDT's response to our initial comments that FERC expects this standard to require the identification of relevant sub 200KV facilities, but for the reasons presented in these comments, we believe that sub 200KV facilities relevant to wide area reliability are few and there should not be an expectation or requirement for the PCs to identify significant portions of sub 200kv facilities for purposes of this standard. Such facilities should be included only when the PC has documented a need.

11. As stated in the background information above, in response to industry comments, the Requirement for the Planning Coordinator to document method for identification of applicable sub-200kV transmission lines (the new R11) is developed. Additionally the SDT assigned Time Horizons, Violation Risk Factors, and Violation Severity Levels. Do you agree? If not, please explain and propose an alternative.

Organization	Yes or No	Question 11 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	

Organization	Yes or No	Question 11 Comment
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	

Organization	Yes or No	Question 11 Comment
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Progress Energy Carolinas, Inc.	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 11 Comment
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Puget Sound Energy	Agree	Assuming the Planning Coordinator is approved through the functional model revisions and entities register for it.
JEA	Agree	Might want to consider adding something along the lines of "for the purposes of vegetation management" at the end to clarify the purpose of the list.
Southern California Edison Company	Agree	SCE generally agrres with the requirement, but is concerned about the role identified for the Planning Coordinator and the possibility that it will have shared compliance responsbilities with the Transmission Owner for certain identified lines.
Public Service Co. of New Mexico	Disagree	Again, see comment from Question 12 - no definition of the term "Planning Coordinator."
American Transmission Company	Disagree	ATC proposes the following:Remove both R10 and R11 because the TPL-002 and TPL-003 standards already require the Transmission Planner and the Planning Coordinator to ensure reliable system operation for loss of single-element and multi-element contingencies. ATC recommends changing the appropriate text in the first two items under A4.2, Facilities: to ". . . transmission lines operated below 200kv that are identified as an element of an IROL or Major WECC Transfer Path".In addition, TPL-002 and TPL-003 require the TP and PC to identify IROL's so that the applicability section of this document should use the outcome from those approved Reliability Standards as an input for this standard. Structuring the standard in this way will makes future enhancement efforts more efficient.If the R10 and R11 removal suggestion is rejected, then revise R11 to, ". . . its methodology for assessing which, if any, lines are subject to this standard. The methodology shall describe the process for determining which lines, if any, below 200kV are expected to have an unacceptable

Organization	Yes or No	Question 11 Comment
		instability or cascading outcome due to TPL-002 and TPL-003 conditions.”
NERC Standards Review Subcommittee	Disagree	See comments above in Question 10.
Platte River Power Authority Vegetation Management Group	Disagree	The criteria for assessing the lines whose loss would place the gird at an unacceptable risk of instability, separation, or cascading failures needs to be more clearly defined. We interpret R10 and R11 to mean that any Category B contingency of a sub-200kV line that causes instability, separation, or cascading failure is subject to FAC-003-2. Is this your desired level of assessment?
Hydro-Quebec TransEnergie (HQT)	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed. See also Q10 answer.
Independent Electricity System Operator	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
ISO New England Inc.	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
Northeast Power Coordinating Council--RSC	Disagree	This should apply to all BES transmission facilities. The use of 200kV as a threshold should be removed.
FirstEnergy Corp	Disagree	We propose the removal of requirement R11. See our response to Question 10 for further details.
ISO/RTO Council		The SRC has no comment on this question.

12. The SDT received suggestions from commenters to re-sequence the requirements contained in the standard to improve the logical flow of this document. The SDT submits for consideration a proposed alternative sequence. Do you agree with the proposed alternative sequencing? If not, please recommend a suggested sequence.

Organization	Yes or No	Question 12 Comment
Entegra Power Group LLC		No comment
Pepco Holdings, Inc - Affiliates (PHI)		No preference. All standards must be considered in entirety for compliance.
Ameren	Agree	
American Electric Power	Agree	
Arizona Public Service	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entergy Services, Inc	Agree	
Georgia Transmission	Agree	

Organization	Yes or No	Question 12 Comment
Corporation		
Hydro One Networks inc.	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	

Organization	Yes or No	Question 12 Comment
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern California Edison Company	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	

Organization	Yes or No	Question 12 Comment
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	As per our answer to Q5, R5 and R6 should be combined to R5 with the elimination of the IROL concept.
American Transmission Company	Agree	ATC agrees generally with the rearrangement. We believe that the proposed requirements R11 and R10 should be removed because can be adequately covered in the applicability section of this document. The remaining proposed reorder would then be okay.
MRO NERC Standards Review Subcommittee	Agree	N/A
ReliabilityFirst Corporation	Agree	This proposed sequence flows better. Feel that R10 and R11 can be combined into one.
JEA	Agree	Would not the Vegetation Inspections be documented in the Work Plan? Perhaps those two should be switched or combined. I'd move Implement Imminent Threat to the end.
Associated Electric Cooperative,	Disagree	Associated Electric Cooperative Inc. believes the current requirements sequence is appropriate.

Organization	Yes or No	Question 12 Comment
Inc.		
Northern Indiana Public Service Company	Disagree	Prefer current sequence except I have no objection to placing the PC requirements at the top of the list.
New Brunswick Power Transmission	Disagree	Propose further revision of "alternate sequence" to R1-4, R6, R5, R7, R10, R11, R9, R8. Suggested proposal reflects dealing with high priority issues first. That is imminent threats must be handled before planned work. Similarly for prevention of outages grow-ins are the most critical, followed by blow-ins and fall-ins.
Central Maine Power an Energy East Company	Disagree	Suggest reverse R4 with R5.
FirstEnergy Corp	Disagree	While we don't have a strong opinion on this, we believe the proposed sequence of R8, R9, R10 and R11 (old R8, R7, R6 and R5) would be better placed in the following order using the teams designated proposed numbering: R11, R10, R8 and R9. This order is suggested so that a greater emphasis on grow-in and IROL is accomplished and that the standard addresses those items first.
ISO/RTO Council		The SRC has no comment on this question.

13. The Implementation Plan proposes an effective date that gives entities at least a year to become fully compliant. Do you agree with this implementation plan? If not, please indicate what should be changed and indicate why.

Organization	Yes or No	Question 13 Comment
Ameren	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Entegra Power Group LLC	Agree	

Organization	Yes or No	Question 13 Comment
FirstEnergy Corp	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating	Agree	

Organization	Yes or No	Question 13 Comment
Council--RSC		
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Pepco Holdings, Inc - Affiliates (PHI)	Agree	
Platte River Power Authority Vegetation Management Group	Agree	
Progress Energy Carolinas, Inc.	Agree	
Public Service Co. of New Mexico	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
Southern California Edison Company	Agree	

Organization	Yes or No	Question 13 Comment
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
US Bureau of Reclamation	Agree	
Vegetation Management Team	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
American Electric Power	Agree	The one year should be adequate presuming that the Planning Coordinator does not designate significant numbers of facilities below 200 kV. Should this become the case, a year would be insufficient to for implementation.

Organization	Yes or No	Question 13 Comment
MRO NERC Standards Review Subcommittee	Disagree	MRO NSRS does not believe that current proposed implementation time in Facilities 4.2.2 is adequate. Given the time required to conduct a survey to determine if a company's lines are maintained sufficiently to meet the new requirements, in addition to the time and resources (both budgetary and labor) required to implement the results of the survey, we believe that between 24 and 36 months may be required to implement this version of the standard.
SCE&G	Disagree	SCE&G believes that this standard is superior to the existing standard and therefore requests that the effective date be moved up. We also recommend that the new standard be started on a calendar year.
Southern Company	Disagree	SDT should consider a more rapid implementation plan because the new standard has significant improvement over the existing standard. For example, Southern Company feels it could be implemented the first calendar day of the first calendar quarter following approval by the NERC Board of Trustees.
SERC Vegetation Managment Sub-committee (VMS)	Disagree	The VMS believes that this standard is superior to the existing standard and therefore requests that the effective date be moved up. The VMS also recommends that the new standard be started on a calendar year.
Entergy Services, Inc	Disagree	This Standard should move forward prior to the current one year provided, it is far superior to the existing Standard.
ISO/RTO Council	Agree	If this standard retains the need to identify sub 200KV facilities, then one year provides sufficient time for Planning Coordinators to meet R10 and R11.

14. Do you have further questions about the standard that the Technical Reference document (White Paper) does not clear up? If so, please elaborate and propose additions.

Organization	Yes or No	Question 14 Comment
Xcel Energy		(a) To avoid confusion, the diagrams of the ROWs in the White Paper should not have tree-like objects in the Active Transmission Right of Way. If any vegetation is to be shown in those areas, the vegetation should be shrubbery.(b) The discussion on p. 24 indicates that the MVCD is the "spark-over zone." The MVCD (hopefully to be renamed) should not directly correlate to the spark-over zone. The spark-over zone should be less than the MVCD.
Hydro One Networks inc.		(a) we suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW." These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.(b) Confusion still exists around the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: Is it up to the Transmission Operator to determine the "active transmission line right-of-way", particularly in cases where the RoW may not be maintained to the legal boundary? Example 4 in the definition of "active transmission line right-of-way" (pg. 5) uses the words "deactivated" and "unavailable for service"; these terms should be clearly defined, as there can be several degrees of de-activation and entities may interpret them differently.
BC Transmission Corporation		Active ROW needs to be defined in more detail
Arizona Public Service		Active ROW needs to defined in more detail.
Consolidated Edison Company of New York Inc.		CECONY recommends that an illustration of R7 be added to the Technical Reference document. R7 text states " ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW." These words could be interpreted to mean that sustained outages from vegetation (branches) extending into the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.
Duke Energy		During the first comment period, it was noted that it was difficult to prove a negative. This will be the case with some of the requirements proposed in this version. For example, it would be beneficial to note in the Technical Reference Paper that documented vegetation inspections that do not identify an encroachment (R4

Organization	Yes or No	Question 14 Comment
		violation) would be proof of compliance. Other examples may exist that the team may consider including for reference.
Entegra Power Group LLC		In some way address dealing with Generator Interconnection Facilities (GIF) which only have a few spans of transmission interconnect. Will this be addressed in a future specific Standard, or as a separate requirement under FAC-003-2? Entegra suggests a much simpler approach can be employed when under 4 spans worth of vegetation can be visually inspected every 1-2 years and trimmed to prevent any possible vegetation impact to subject lines/system.
Tampa Electric Company		In the white paper, page 35, paragraph 2, it states that if the conductor is operating above its rating it "would not be classified as vegetation related sustained outage under the standard." If this is so it needs to be stated and/or clarified in the standard itself. In addition on page 35, 3rd paragraph, last sentence of the white paper it states, " Additionally, sustained outages due to wind-blown debris, such as large limbs and branches, separated tree tops, etc., are exempt from this standard." If this is so it needs to be stated in the standard. Need clarification, if the debris is from trees within the active transmission ROW is it a violation?
Tucson Electric Power Company		In the white paper, the pictorial reference of the active right of way has no reference to show what the minimum distance beyond the conductor envelope should be to establish the width of the active right of way.
US Bureau of Reclamation		It is not clear at what physical point in the BES the is standard would apply; such as from the first structure outside of the substation/switchyard or other demarcation.
National Grid		National Grid suggests an illustration of R7 be added. R7 text states " ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity that these sustained outages are a violation of R7.
ReliabilityFirst Corporation		No
TVA		no
WECC RC		NO
Associated Electric Cooperative,		No comments

Organization	Yes or No	Question 14 Comment
Inc.		
North Carolina Electric Membership Corporation		None
SCE&G		None
SERC Vegetation Managment Sub-committee (VMS)		None.
Southern Company		None.
Pepco Holdings, Inc - Affiliates (PHI)		PHI has concerns that the reference document has many items that are critical to the determination of compliance.
CenterPoint Energy		Questions are listed below:1. How does the Transmission Owner determine the geometric limits of an “Active Transmission Line Right of Way” to determine how a Sustained Outage is reported under Category 1A, Category 1B, Category 2, and Category 4.2. Why does an “Inactive R.O.W.” contain trees that are within falling distance of an applicable transmission line? (Figure 1 has such a depiction.) Is the “Inactive R.O.W. outside the legal limits of the Transmission Owners’ right of way?3. Why don’t Requirements 5, 6, 7 and 8, and their corresponding Measures 5, 6, 7, and 8, and the Compliance 1.5 Sustained Outage Categories - Category 1A, Category 1B, Category 4, and Category 2 all have the same exceptions listed? For example, R5 has the exceptions for “Sustained Outages of applicable lines that result from natural disasters” and Sustained Outages of applicable lines that result from human or animal activity.” M5 and Category 1A do not contain those exceptions. Category 1A qualifies events to be reported as “inside and/or outside of the Active Transmission Line ROW”, but R5 and M5 do not have such a reference. How will the reporting differentiate between a Sustained Outage caused by improper vegetation management and those caused by natural disasters? FAC-003-1 R3.2 did not require the reporting of certain sustained transmission line outages (e.g. natural disasters, human activity, etc.). It is not clear what the current draft intends to have reported.
Nebraska Public Power District		Remove the tree-like objects from the diagrams of the ROWs in the White Paper. If any vegetation is to be shown in those areas, the vegetation should only be shrubbery.
Entergy Services, Inc		See additional Entergy comments below.

Organization	Yes or No	Question 14 Comment
Orange and Rockland Utilities, Inc.		Suggest an illustration of R7 be added. R7 text states " ... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.
Hydro-Quebec TransEnergie (HQT)		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the "active transmission line right-of-way", particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of "active transmission line right-of-way" (pg. 5) uses the words "deactivated" and "unavailable for service". The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Independent Electricity System Operator		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the "active transmission line right-of-way", particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of "active transmission line right-of-way" (pg. 5) uses the words "deactivated" and "unavailable for service". The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
ISO New England Inc.		Suggest an illustration of R7 be added. R7 text states "... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW". These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the "active transmission line right-of-way". The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions.

Organization	Yes or No	Question 14 Comment
		Specific questions include: is it up to the Transmission Operator to determine the “active transmission line right-of-way”, particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of “active transmission line right-of-way” (pg. 5) uses the words “deactivated” and “unavailable for service”. The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Northeast Power Coordinating Council--RSC		Suggest an illustration of R7 be added. R7 text states “... due to the blowing together of vegetation and a conductor within an Active Transmission Line ROW”. These words could suggest that sustained outages from vegetation (branches) extending within the active ROW, but originating from trees located outside the active ROW, might not be considered a preventable outage. An illustration in the reference paper would provide clarity.Confusion still exists regarding the determination of the “active transmission line right-of-way”. The diagrams shown in the white paper, though helpful, do not necessarily apply to all field conditions. Specific questions include: is it up to the Transmission Operator to determine the “active transmission line right-of-way”, particularly in cases where the ROW may not be maintained to the legal boundary? Example 4 in the definition of “active transmission line right-of-way” (pg. 5) uses the words “deactivated” and “unavailable for service”. The terms active, deactivated, and unavailable for service should be clearly defined as they can easily be interpreted different ways between different entities, and for different situations.
Vegetation Management Team		The Active ROW definition should be expanded to exclude areas of the ROW that are currently being used for other transmission facilities, such as 110 kV towers etc. As written, it only excludes unused portions of the ROW, abandon lines and the side of structures that have no facilities. Perhaps use “A strip of land that is occupied by applicable transmission facilities.The last paragraph on page 8 of the Technical Reference indicates that the Standard is not applicable to “...line sections inside the electric station or other boundary...” This is somewhat ambiguous on who has the responsibility of assure compliance “inside the fence or other boundary”.
Salt River Project		The Active ROW should be defined in more detail.
Public Service Co. of New Mexico		The Planning Coordinator is not defined. Please clarify who this person(s) are.Additionally there needs to be more specific language regarding the importance of this reliability standard specifically for dealings with Federal, State or Tribal authorities.
American Electric Power		The SDT has done a great job developing this version of the standards, responding to comments, and enhancing the Technical Reference document. We have no other questions at this time.
Utility Arborist Association		The UAA commends the standards drafting team for covering ANSI A300, Part 7 and the International Society

Organization	Yes or No	Question 14 Comment
		of Arboriculture's integrated vegetation management best management practices in the technical reference. The UAA considers the treatment to be a reasonable representation of best practices to use in complying with FAC-003-02. We remain convinced that best management practice implementation is the most effective way to improve reliability. The A300 section in the technical reference is an important contribution in that regard. We reiterate our view that ANSI A300 be included in the requirements rather than as a footnote in the standard.
MRO NERC Standards Review Subcommittee		To avoid confusion, the diagrams of the ROWs in the White Paper should not have tree-like objects in the Active Transmission Right of Way. If any vegetation is to be shown in those areas, the vegetation should be shrubbery.
Northern Indiana Public Service Company		When discussing R4 (Pg. 30), the document brings up the concept of identifying encroachments of the MVCD during inspections but doesn't discuss indicators present in vegetation that has experienced flashover. For example, at the time vegetation is inspected, offending vegetation may be well outside the minumum distance in Table 1, but still exhibit evidence of sparkover such is wilted leaves, scorched limbs, etc. It would be helpful for the document to discuss these and other indicators of encroachment into the MVCD in greater detail.

15. As stated in the background information above, in response to industry comments, the applicability section is revised to replace Reliability Coordinator with Planning Coordinator. Do you agree with these changes? If not, please explain and propose an alternative.

Organization	Yes or No	Question 15 Comment
Entegra Power Group LLC		No comment
Tampa Electric Company		We do not agree or disagree on this Requirement.
Ameren	Agree	
American Electric Power	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Bonneville Power Administration	Agree	
CenterPoint Energy	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	

Organization	Yes or No	Question 15 Comment
Duke Energy	Agree	
Entergy Services, Inc	Agree	
FirstEnergy Corp	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
Lee County Electric Cooperative	Agree	
Manitoba Hydro	Agree	
National Grid	Agree	
Nebraska Public Power District	Agree	
NERC Standards Review Subcommittee	Agree	
New Brunswick Power Transmission	Agree	

Organization	Yes or No	Question 15 Comment
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
Salt River Project	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern California Edison	Agree	

Organization	Yes or No	Question 15 Comment
Company		
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
Tucson Electric Power Company	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Xcel Energy	Agree	
JEA	Agree	I agree this makes sense. Unfortunately, at least in FRCC, every TO has TWO Planning Coordinators so unless the RE or NERC straightens that situation out, there will be confusion as to which has the authority.
E.ON U.S.	Disagree	: E.ON U.S. recommends that the RC remain the responsible entity instead of the Planning Coordinator as RCs are best situated to determine a line's criticality to the region.

Organization	Yes or No	Question 15 Comment
Public Service Co. of New Mexico	Disagree	As stated in several earlier questions, there isn't a definition of who this person(s) are and what their duties are? Should be clearly defined in both the standard and in the white paper.
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	PHI concurs with replacing the Reliability Coordinator with the Planning Coordinator. However, PHI has concerns with the Applicability section. 4.2.1 has (-applicable lines-) immediately following the term -transmission lines-, indicating that all Transmission Lines are applicable lines. We are certain that is not what the SDT meant. Additionally, Transmission Line is a NERC defined term and includes all Facilities 69kV - 765kV. We assume what is meant is to limit the applicability to BES (BPS) Facilities 200kV and above plus Transmission Lines operated below 200kV designated by the Planning Coordinator.PHI also encourages further consideration for lines from generation facilities to network substations. Some Generator Owners have lines greater than a mile in length. The SDT should consider whether to extend applicability of the standard for Generator Owners that own lines that meeting certain predefined criteria, or other approaches that would clarify the treatment of lines owned by Generator Owners on the generator side of a network substation.
Vegetation Management Team	Disagree	Suggest adding BES to the first bullet under A.4.-Facilities: to clarify that FAC-003-2 only applies to the BES. That radial lines supplying distribution substations, etc. aren't part of the standard. The bullet could read: "Bulk Electric System Transmission lines ("applicable lines") operated at 200kV or higher, and transmission lines operated below 200kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities."
US Bureau of Reclamation	Disagree	The role should be examined as part of the functional model description. To modify the role in the inidividual standards may result in holes in the fuctional model roles.
Platte River Power Authority Vegetation Management Group	Disagree	We are still finding confusion within the industry about the function of the Planning Coordinator and registration for Planning Coordinator (a.k.a. the Planning Authority). We think a strong possibility exists that there may be Transmission Owners who don't have a Planning Coordinator or assume that their Balancing Authority or a other registered entity is providing this function for them when in reality they are not. This confusion could present a gap in reliability. At one time there was discussion of removing this function from the Functional Model all together and replacing Planning Coordinator with Transmission Planner in all applicable standards. Although the Planning Coordinator and the Transmission Planner are the same within our organization we believe it will provide clarity to the standard to make it applicable to the Transmission Planner opposed to the Planning Coordinator. The coordination of the Transmission Planner would be between the Transmission Owners and neighboring transmission planners in R10.

Organization	Yes or No	Question 15 Comment
ISO/RTO Council	Agree	If this standard retains the need to identify sub 200KV facilities, then the change of this responsibility from the Reliability Coordinator to the Planning Coordinator is appropriate.

16. As stated in the background information above, in response to industry comments, changes were made to the definitions. Do you agree with these changes? If not, please explain and propose an alternative.

Organization	Yes or No	Question 16 Comment
Entegra Power Group LLC		No comment
American Electric Power	Agree	
American Transmission Company	Agree	
Arizona Public Service	Agree	
Associated Electric Cooperative, Inc.	Agree	
BC Transmission Corporation	Agree	
Central Maine Power an Energy East Company	Agree	
Consolidated Edison Company of New York Inc.	Agree	
Duke Energy	Agree	
E.ON U.S.	Agree	
Georgia Transmission Corporation	Agree	
Hydro One Networks inc.	Agree	

Organization	Yes or No	Question 16 Comment
Hydro-Quebec TransEnergie (HQT)	Agree	
Idaho Power Company	Agree	
Independent Electricity System Operator	Agree	
ISO New England Inc.	Agree	
JEA	Agree	
Lee County Electric Cooperative	Agree	
Nebraska Public Power District	Agree	
New Brunswick Power Transmission	Agree	
North Carolina Electric Membership Corporation	Agree	
Northeast Power Coordinating Council--RSC	Agree	
Northeast Utilities	Agree	
Northern Indiana Public Service Company	Agree	
Oncor Electric Delivery	Agree	
Orange and Rockland Utilities, Inc.	Agree	

Organization	Yes or No	Question 16 Comment
Pacific Gas and Electric Co.	Agree	
PacifiCorp	Agree	
Progress Energy Carolinas, Inc.	Agree	
Puget Sound Energy	Agree	
ReliabilityFirst Corporation	Agree	
SCE&G	Agree	
SERC Vegetation Managment Sub-committee (VMS)	Agree	
Southern Company	Agree	
Superintendent Transmission Maintenance	Agree	
Tampa Electric Company	Agree	
Tenessee Valley Authority	Agree	
Tennessee Valley Authority	Agree	
Transmission Owner	Agree	
TVA	Agree	
TVA	Agree	
TVA	Agree	

Organization	Yes or No	Question 16 Comment
WECC RC	Agree	
Western Area Power Administration, Rocky Mountain Region	Agree	
Bonneville Power Administration	Agree	“Response Control Center” is not defined in the NERC Glossary of Terms, so it either needs to be added to the Glossary and/or defined within the Standard to be clear regarding its definition.
Edison Electric Institute	Agree	EEI also recommends that the SDT reconsider use of the term ‘applicable lines’ in the revised draft Standard or clarify the definition. The way the Standard is written with the term “applicable lines” in parentheses and quotes after the words “Transmission lines” in section 4, the term “applicable lines” would under normal interpretation rules be interpreted to mean “Transmission lines.” This surely is not the intent of the SDT. If “applicable lines” is meant to be the facilities defined in Section 4, then EEI recommends modifying Section 4 “Facilities” to read: “Facilities (‘applicable lines’)” if that is the intent to the term ‘applicable lines.’ If not, then the term needs a more specific definition.While applicability of the Standard is already described, use of this term in specific requirements could suggest that there may be lines that are otherwise subject to requirements of the Standard and only ‘applicable lines’ are addressed in some requirements. For example, the sentence ‘Sustained Outages of applicable lines that result from natural disaster,’ could be interpreted to refer to lines affected by a natural disaster, or some other subset of all lines subject to the Standard. EEI recommends that the SDT consider revising language of this type to remove the phrase ‘applicable lines.’ In the example cited, the sentence would become a clause reading: ‘Sustained Outages that result from natural disasters.’
National Grid	Agree	National Grid agrees with the new definition for active transmission right-of-way, though it may need further clarification in the Technical reference document. We have concerns that TO’s might consider portions of the original ROW width as not active. For example: Original width of a ROW was 100 feet, however over many decades the maintained width has been reduced to 80 feet. Might the new definition provide incentive for the TO to now define the active ROW as 80 feet? The proposed removal of the requirement to report Category 3 sustained outages provides additional incentive for the TO to adopt this approach.
Southern California Edison Company	Agree	SCE generally agrees with the definitions, but suggests that the "Vegetation Inspection" definition be revised to read: Vegetation Inspection - The systematic examination of vegetation conditions within an Active Transmission Line Right of Way. A Vegetation Inspection may be combined with other transmission facility inspections.

Organization	Yes or No	Question 16 Comment
FirstEnergy Corp	Agree	We agree with the definitions, but want to point out that this is the only standard that would utilize the term Vegetation Inspection, and the current definition is not used anywhere in the currently approved set of NERC standards. Should this definition only be specific to this standard and not a NERC glossary term? Regardless, we do not have an issue either way.
Xcel Energy	Disagree	(a) The definition of Active Transmission Line Right of Way is confusing. There may be other portions of the Right of Way that were not specifically acquired for other facilities (or being used for other facilities), but are not used and are not needed. As drafted, this definition would ignore this fact. Further, by limiting the definition in this manner, it ignores the fact that it may take different portions of the right of way to operate the line (due to the characteristics of the line, size, location, etc.) and address vegetation concerns. It would be more accurate if the “intended for other facilities” portion of the definition were deleted. This would allow the flexibility to address the concerns noted above. Thus it would read: "A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the right of way."(b) The definition of “Vegetation Inspection” should be rewritten to change the documentation requirement for any vegetation which “may pose a threat.” As a practical mater, any vegetation “may” pose a threat. The definition would be better phrased to read: "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 poses an unacceptable risk to reliability prior to the next planned inspection or maintenance work."
Platte River Power Authority Vegetation Management Group	Disagree	“intended for other facilities” should be struck from the definition of Active Transmission Line Right of Way as it may include deactivated transmission lines, buffer zones or other ROW never intended for other facilities but wider that necessary.
Tucson Electric Power Company	Disagree	1- In the definition of the term “Active Transmission Right of Way” the final sentence should read “This corridor does not include the inactive or unused part of the Right of Way.” Delete intended for other facilities. 2- We propose the following modification to the Vegetation Inspection definition the sentence; “The inspection includes the documentation of any vegetation that may pose a threat unacceptable risk to reliability prior to the next planned inspection or maintenance work”. This would make the language consistent with other language found in M11 of this document.
MRO NERC Standards Review Subcommittee	Disagree	A. The definition of Active Transmission Line Right of Way is confusing. There may be other portions of the Right of Way that were not specifically acquired for other facilities (or being used for other facilities), but are not used and are not needed. It would be more accurate if the text “intended for other facilities” was deleted. Thus it would read: “A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the right of way.”B. The definition of “Vegetation Inspection” should be

Organization	Yes or No	Question 16 Comment
		rewritten to change the documentation requirement for any vegetation which "may pose a threat." As a practical matter, any vegetation "may" pose a threat. The definition would be better phrased to read: "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 poses an unacceptable risk to reliability prior to the next planned inspection or maintenance work."
Pepco Holdings, Inc - Affiliates (PHI)	Disagree	Active Transmission Line Right of Way should include the buffer needed to maintain clearances. Width needs to be sufficient to maintain clearances. This should be identified by the TO.
CenterPoint Energy	Disagree	Active Transmission Line Right of WayCenterPoint Energy disagrees with the inclusion and definition of "Active Transmission Line Right of Way". "Active Transmission Line Right of Way" is not defined as to its geometric limits within the Standard. The SDT has indicated in its response to 1st Draft Comments from CenterPoint Energy that the "...Transmission Owner is responsible for defining the Active Transmission Line Right of Way." However, that defining clause is not included in the current definition. CenterPoint Energy recommends one of the following options in order of preference:1) Recommend deleting the term "Active Transmission Line Right of Way" from the standard and revising the Requirements, Measures, and Compliance line items accordingly. R1.6 already requires that maintenance strategies ensure that the MVCD is never violated and considers "the sag and sway of the conductor throughout is operating range and under rated conditions". This requirement by itself defines the airspace that must be maintained to prevent a Sustained Outage for grow-ins and blow-ins. R7 would be revised to read "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to the blowing together of vegetation and a conductor operating within its designed sway under rated conditions with the following exceptions...".R8 would be revised to read, "Each Transmission Owner shall prevent Sustained Outages of applicable lines due to vegetation falling into a conductor where the Transmission Owner had the legal right or prior permission to remove the vegetation."2) To parallel the requirement of R1.6, revise the definition of "Active Transmission Line Right of Way" to, "A strip of land that is occupied by applicable lines considering the sag and sway of the conductor throughout its operating range under rated conditions plus the Minimum Vegetation Clearance Distance (MVCD) from Table 1, where applicable lines are defined as transmission lines operating in real time at 200kV or higher and transmission lines operating in real time below 200kV designated by the Planning Coordinator as being subject to this standard, including but not limited to those lines that cross lands owned by federal, state, provincial, public, private, or tribal entities."3) If the SDT and NERC intend for the Active Transmission Line Right of Way limits to be determined based on the Transmission Owner's interpretation, CenterPoint Energy suggests an alternate definition as follows, "Active Transmission Line Right of Way - A strip of land, the dimensions of which are determined by the Transmission Owner, occupied by applicable lines, where applicable lines are defined as transmission lines operating in real time at 200kV or higher and transmission lines operating in real time below 200kV designated by the Planning Coordinator as being

Organization	Yes or No	Question 16 Comment
		subject to this standard, including but not limited to those lines that cross lands owned by federal, state, provincial, public, private, or tribal entities."By making this suggested change to the definition of "Active Transmission Line Right of Way", most of the ambiguity is removed. It is now clear that the standard does not apply to those portions of rights-of-way in which there are no applicable lines, such as 69kV and 138kV lines that the Planning Coordinator has not determined to be subject to the standard. CenterPoint Energy has added the phrase "operating in real time" to make it clear that the standard also does not apply to a right-of-way in which there is a non-operating line which would normally be subject to the standard if it was operating. By adding MVCD and "sag and sway" requirements to the definition of "Active Transmission Line Right of Way", the standard has defined the physical limits necessary to determine if there has been a violation from trees adjacent to the applicable lines. The alternate definition without the MVCD citation clarifies who is to determine the physical limits of the Active Transmission Line Right of Way since none are provided in the definition itself. However, adding such a reference would surmount to a "fill-in-the-blank" requirement which the SDT has found undesirable. Vegetation InspectionCenterPoint Energy disagrees with the definition of "Vegetation Inspection" since it includes the term "Active Transmission Line Right of Way" which is ambiguously defined and not relevant to defining the type of inspection performed. CenterPoint Energy recommends the following definition, "Vegetation Inspection - The systematic examination of vegetation conditions under and adjacent to a transmission line considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions. 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."
Salt River Project	Disagree	For the definition of "Vegetation Inspection" recommend the following changes:- In the 3rd sentence, the use of "threat", change to "unacceptable risk"- In the 3rd sentence, remove the last statement "...consider the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions". The definition is too lengthy and it does not appear this additional language is necessary.
Vegetation Management Team	Disagree	MVCZ should be included in the Definitions of Terms Used in Standard.
Public Service Co. of New Mexico	Disagree	PNM recommends ammending the definition of "Active Transmission Line Right of Way" as follows: A strip of land that is occupied by active transmission facilities. This corridor does not include the inactive or unused part of the Right of Way.PNM recommends ammending "Vegetation Inspection" to include acceptable types of inspection methods i.e. ground patrols, aerial patrols, etc.
Entergy Services, Inc	Disagree	See additional Entergy comments below.
Manitoba Hydro	Disagree	the definition of "active ROW" should include the concept of meeting safe/reliable operation design criteria

Organization	Yes or No	Question 16 Comment
US Bureau of Reclamation	Disagree	The definitions should not include performance measures or suggestions such as "This inspection may be combined with a general lineinspection." The definition is also phrased in terms of a requirement by using "The inspection includes the documentation of any vegetation that may pose a threatto 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." Both of these quoted phrases should be removed to the requirements section.
Ameren	Disagree	Vegetation Inspection:Need to insert that these inspections are based on inspectors expectation of normal growth and environmental factors or note that the inspector can not determine all hazards from vegetation that may occur from natural disasters or human or animal activity when inspecting. This would be a complimentary statement to the exceptions for actual events that occur in these requirements.
ISO/RTO Council		The SRC has no comment on this question.

17. When compared to Version 1, does this proposed Version 2 of the standard either maintain or improve overall electric reliability? Please provide a technical basis for your response?

Organization	Does or Does Not	Question 17 Comment
Entegra Power Group LLC		No comment
Southern California Edison Company		Uncertain. At this point in time, SCE does not believe that it is possible to predict whether Version 2 will improve overall electric reliability when compared with Version 1 because NERC has not yet demonstrated with documentation that the implementation of Version 1 of FAC-003 has improved electric reliability.
Ameren	V2 Does maintain or improve overall reliability	
CenterPoint Energy	V2 Does maintain or improve overall reliability	
Central Maine Power an Energy East Company	V2 Does maintain or improve overall reliability	
Duke Energy	V2 Does maintain or improve overall reliability	
Entergy Services, Inc	V2 Does maintain or improve overall reliability	
FirstEnergy Corp	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Georgia Transmission Corporation	V2 Does maintain or improve overall reliability	
Idaho Power Company	V2 Does maintain or improve overall reliability	
Lee County Electric Cooperative	V2 Does maintain or improve overall reliability	
Manitoba Hydro	V2 Does maintain or improve overall reliability	
Nebraska Public Power District	V2 Does maintain or improve overall reliability	
Northeast Utilities	V2 Does maintain or improve overall reliability	
Oncor Electric Delivery	V2 Does maintain or improve overall reliability	
Pacific Gas and Electric Co.	V2 Does maintain or improve overall reliability	
Pepco Holdings, Inc - Affiliates (PHI)	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Platte River Power Authority Vegetation Management Group	V2 Does maintain or improve overall reliability	
Progress Energy Carolinas, Inc.	V2 Does maintain or improve overall reliability	
ReliabilityFirst Corporation	V2 Does maintain or improve overall reliability	
Tenessee Valley Authority	V2 Does maintain or improve overall reliability	
Transmission Owner	V2 Does maintain or improve overall reliability	
Tucson Electric Power Company	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	
TVA	V2 Does maintain or improve overall reliability	

Organization	Does or Does Not	Question 17 Comment
Vegetation Management Team	V2 Does maintain or improve overall reliability	
WECC RC	V2 Does maintain or improve overall reliability	
Xcel Energy	V2 Does maintain or improve overall reliability	
SCE&G	V2 Does maintain or improve overall reliability	As stated, SCE&G believes that this standard version is superior to the previous. Improvement areas include: o Clarification is made that sustained outages are a violation of the requirements. o Separation of imminent threat, vegetation inspections and the annual work-plan have been made. o Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. o Established a clear process for identifying sub 200kV circuits applicable to the revised standard. o Clarification of the active ROW o This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.) o Applies to applicable transmission facilities regardless of location o Focus is made to actual and observable conditions rather than hypothetical conditions. o Addresses the elements of FERC order 693
SERC Vegetation Managment Sub-committee (VMS)	V2 Does maintain or improve overall reliability	As stated, the SERC VMS believes that this standard version is superior to the previous. These improvements include:Clarification is made that sustained outages are a violation of the requirements. Separation of imminent threat, vegetation inspections and the annual work-plan have been made. Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. It establishes a clear process for identifying sub 200kV circuits applicable to the revised standard. Clarification of the active ROW is made.This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.)Applies to applicable transmission facilities regardless of location.Focus is made to actual and observable conditions rather than hypothetical conditions.It addresses the elements of FERC order 693.
American Transmission	V2 Does maintain or improve overall	ATC believes that the standard provides for improved reliability, however, needs to consider ATC's

Organization	Does or Does Not	Question 17 Comment
Company	reliability	comments to earlier questions.
Bonneville Power Administration	V2 Does maintain or improve overall reliability	BPA believes V2 maintains overall reliability. Although there are many differences between the two versions, the overall differences between version 1 and version 2 appear to have the same impact on reliability.
Consolidated Edison Company of New York Inc.	V2 Does maintain or improve overall reliability	CECONY believes that the Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, reduced ambiguity, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
E.ON U.S.	V2 Does maintain or improve overall reliability	E.ON U.S. believes the proposed revision provides much greater clarity to the requirements than what is currently in place.
Edison Electric Institute	V2 Does maintain or improve overall reliability	EEI applauds the commitment and effort of the SDT and appreciates the revised draft FAC-003 Standard as a complete response to the key issues raised by FERC in Order No. 693:o NERC has addressed applicability issues, balancing the need for covering facilities that impact reliability against unreasonably increasing the burden of transmission owners.o NERC has addressed minimum clearance issues, proposing requirements that will avoid vegetation-related sustained outages for lines on both federal and non-federal lands.o NERC has proposed changes to applicability to better recognize differing needs for active and inactive rights-of-way. o NERC has addressed inspection cycles to ensure that inspections are conducted at reasonable intervals.Overall, EEI believes that the Standard can provide adequate requirements for company vegetation management programs for maintaining clearances on rights-of-way on the Bulk Power System. Compliance with these requirements would, if established as mandatory by FERC, support reliable operation of the Bulk Power System by preventing Sustained Outages caused by vegetation.The electric industry broadly recognizes that several Reliability Standards contain ambiguous terms and requirements, which have resulted in significant challenges for companies in seeking to determine appropriate compliance actions, and for compliance enforcement activities within NERC. EEI strongly supports the general process for improving the Standards development process and content of the Standards as a long-term goal for NERC. In the context of revising

Organization	Does or Does Not	Question 17 Comment
		FAC-003, to the maximum extent practicable EEI encourages the SDT to use defined terms and explicit references. EEI recognizes also that the need to reduce ambiguity must be balanced against the need to adapt flexible requirements and measures that recognize the widely varying vegetation circumstances on the Bulk Power System. This is especially challenging for developing enforceable requirements to address vegetation encroachment issues on transmission rights-of-way.
Tennessee Valley Authority	V2 Does maintain or improve overall reliability	I believe it improves reliability.
Associated Electric Cooperative, Inc.	V2 Does maintain or improve overall reliability	It is Associated Electric Cooperative Inc's opinion that V2 maintains overall reliability as compared to V1. o Developing separate requirements for documentation and implementation of the Imminent Threat Process, Vegetation Inspections, and the Annual Work Plan adds to the clarity of the standard.
North Carolina Electric Membership Corporation	V2 Does maintain or improve overall reliability	NCEMC does believe that this standard version is an improvement to the previous. Improvement areas include:o Clarification is made that sustained outages are a violation of the requirements. o Separation of imminent threat, vegetation inspections and the annual work-plan have been made. o Minimum clearance distances are realistic and eliminates references outside the standard (via Appendix 1). The fill-in-the-blank aspects are eliminated. o Established a clear process for identifying sub 200kV circuits applicable to the revised standard. o Clarification of the active ROW.o This revision eliminates non enhancing aspects of the previous version (e.g. personnel qualifications, category 3 reporting, clearance 1, etc.)o Applies to applicable transmission facilities regardless of locationo Focus is made to actual and observable conditions rather than hypothetical conditions.o Addresses the elements of FERC order 693
Southern Company	V2 Does maintain or improve overall reliability	The new standard differentiates between IROL and non IROL facilities. The use of the Planning Coordinator in lieu of the Reliability Coordinator provides a long term approach to improving reliability. The definition of active ROW helps differentiate between important ROW and less important ROW.
Western Area Power Administration, Rocky Mountain Region	V2 Does maintain or improve overall reliability	The proposed Version 2 of the Standard improves overall system reliability by: 1) Clarifying previously ambiguous requirements of Version 1 regarding what is or is not a violation of the Standard. For example, previously unclear expectations associated with Version 1 requirements R1.2.2. and R3 are now clearly addressed as requirements in Version 2 requirements R4, R5, R6,

Organization	Does or Does Not	Question 17 Comment
		R7 and R8. 2) Providing real time, observable and measurable thresholds for compliance in Version 2 verses the many subjective and "interpreted" thresholds for compliance which were contained in Version 1 requirements. 3) Requiring a series of pro-active, mandatory and graduated actions by the Transmission Owner for preventing vegetation related outages that could lead to cascading events. These "layers of protection" include the formal identification of facilities subject to the standard, the establishment of a credible TVMP and execution of annual plans, mandatory field inspections, prevention of encroachments into Minimum Vegetation Clearance Distances, mitigation of imminent threats, prevention of outages due to fall ins, prevention of outages due to blow ins, and the prevention of outages due to grow ins.
JEA	V2 Does maintain or improve overall reliability	The standard seems to maintain reliability and add clarity.
American Electric Power	V2 Does maintain or improve overall reliability	This standard is a significant improvement in its specificity of the documentation and reporting responsibilities necessary to be fully compliant.
MRO NERC Standards Review Subcommittee	V2 Does maintain or improve overall reliability	Using the Gallet equation puts the tree trimmers closer to the lines than the OSHA standards will allow due to the fact that OSHA recognizes the standard IEEE 516-2003 clearance distances. We recommend revising Table 1 taking into account the IEEE standard.
New Brunswick Power Transmission	V2 Does maintain or improve overall reliability	V2 is a much improved version of the standard in that it provides clarify on a number of issues; the technical reference is a welcome addition and provides critical information for meeting proposed standard.
Superintendent Transmission Maintenance	V2 Does maintain or improve overall reliability	V2 maintains and improves overall system reliability with real-time, observable, and measurable standards that include a thorough approach (inspections, reporting, MVCDs, etc) to minimizing cascading outages caused by vegetation.
Tampa Electric Company	V2 Does maintain or improve overall reliability	V2 represents the growth of the standard via much improved clarification; I have to think that this will result in a much better overall industry understanding of the standard and its requirements. This should result in improved Industry performance and thus will maintain or improve overall reliability. MVCD is improved via Gallet formula, definitions are new & improved, VRF & VSL's clarify risk and severity.

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US Bureau of Reclamation	V2 Does not maintain or improve overall reliability	It is hard to imagine any vegetation encroachment that would not be exempted by this standard. Overall the exemptions appear to be inconsistent with the language in the respective requirements.
National Grid	V2 Does not maintain or improve overall reliability	National Grid disagrees that V2 will improve reliability for 3 reasons: 1) National Grid believes eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MVCD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) National Grid believes eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. 3) Removing the qualifications requirement from the standard will likely lead to TO's employing less qualified employees and contractors. The Utility Vegetation Management (UVM) industry, through development of ANSI Standards and industry Best Practices, and the International Society of Arboriculture certification programs, has worked to raise the level of professionalism in the UVM industry. National Grid believes that raising professional standards leads to better quality work and improved reliability.
Orange and Rockland Utilities, Inc.	V2 Does not maintain or improve overall reliability	ORU disagrees that V2 will improve reliability for 3 reasons: 1) ORU believes eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) ORU believe eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. 3) Removing the qualifications requirement from the standard will likely lead to TO's employing less qualified employees and contractors. The Utility Vegetation Management (UVM) industry, through development of ANSI Standards, and the International Society of Arboriculture certification programs have worked to raise the level of professionalism in the UVM industry. We believe that raising professional standards leads to better quality work and improved reliability. ORU believes that the Standard

Organization	Does or Does Not	Question 17 Comment
		does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
PacifiCorp	V2 Does not maintain or improve overall reliability	PacifiCorp disagrees that FAC-003-02 will improve reliability because the standard lacks a requirement to adhere to best management practices, it does not mandate that programs be managed by qualified individuals, and it has no clearance 1.
Arizona Public Service	V2 Does not maintain or improve overall reliability	Removing the following sections from FAC-003 version 1 does not improve or maintain reliability; R1.2.1, R1.3. APS has responded in the section above.
Puget Sound Energy	V2 Does not maintain or improve overall reliability	The elimination of Clearance 1 from the current standard, and the close distance to the wire in the proposed Table 1 will create more difficulty with agencies and reluctant landowners. A closer distance to the MVCD will be pushed by some. This revised standard gives Transmission Owner no leverage for maintaining Utiltiy Vegetation management Best Management Practices (BMP). If BMP's were utilitzed consistently, there would be minimum outages.
Salt River Project	V2 Does not maintain or improve overall	The proposed MVCD values are less than SRP has defined in the current standard for Clearance 2 values and would not provide adequate clearance. Also see comments stated in question #4

Organization	Does or Does Not	Question 17 Comment
	reliability	regarding concern regarding the method used to determine the MVCD values.
Utility Arborist Association	V2 Does not maintain or improve overall reliability	The Utility Arborist Association thinks version 2 does not improve reliability over version 1 for two reasons. It does not have a qualification requirement, and it does not contain a requirement for utilities to conform to ANSI A300.First, the UAA considers removal of the qualification requirement from the standard to detract from reliability compared to FAC-003-01. Appropriate qualifications are every bit as critical for vegetation management as they are for other areas of expertise necessary to operate the electric grid. For example, no utility would assign engineering responsibilities to anyone without engineering training and experience, as the electric grid would quickly fail. Yet, it is common for utilities to assign vegetation management oversight to employees without the appropriate knowledge and background to succeed. Consider that none of the three North American blackouts in the past fifteen years occurred solely due to engineering deficiencies. Rather, they were initiated by tree contacts. More effective vegetation management programs would have prevented every one of them. Clearly vegetation management expertise is critical, as the consequences of vegetation management deficiencies have resulted in three catastrophic grid failures. It cannot be left to people with improper or inadequate competencies. The standard should say as much.The Utility Arborist Association recognizes that the qualification requirement has been removed due to industry reaction to unreasonable and overbearing demands for proof of qualifications on the part of some auditors. For example, several utilities complained that auditors required resumes of everyone in the program, including ground workers. Clearly, that goes well beyond what was intended in the FAC-003-01, which was that vegetation management oversight for a transmission operator be in the hands of knowledgeable and competent managers. Arguably, demands for resumes of everyone remotely involved detracts from an effective program by occupying managers with irrelevant paper work, rather than addressing the demands of protecting their systems. On the other hand, poor judgment on the part of some auditors doesn't reduce the need for programs to be designed and implemented by qualified utility arborists. The Utility Arborist Association understands the need to address deficiencies in aptitude among vegetation management auditors, and is responding by developing training programs for them. Our objective is to raise the level of understanding among vegetation management auditors to a level necessary for consistent, fair and reasonable compliance oversight that will contribute to, rather than detract from, electric reliability.Secondly, the Utility Arborist Association considers limiting a reference to ANSI A300 to a footnote to insufficiently emphasize it's criticality to overall electric reliability. The UAA strongly urges adding language to R1.1 and M1.6, and hold utilities accountable for using best management practices. The Utility Arborist Association has worked hard to incorporate sufficient flexibility into integrated vegetation management best management practices to account for the array of environmental, political and technical challenges that might confront vegetation managers anywhere they practice. The Utility Arborist Association is confident that adding them as

Organization	Does or Does Not	Question 17 Comment
		requirements to the standard will improve reliability by raising professionalism and leading to more effective results.
Northern Indiana Public Service Company	V2 Does not maintain or improve overall reliability	There are many instances where V2 contains requirements and/or measures are weaker or less stringent than V1. Examples:1. Elimination of Clearance 1 requirements which have been so instrumental in improving T.O. vegetation maintenance activities on R.O.W.'s (see my comments from Draft 1 of FAC-003-2).2. Elimination of requirement for personnel responsible for design and implementation of TVMPs to hold appropriate qualifications to do so.3. Limitation of Corrective Action Process or Mitigation Measures to instances of temporary constraints to planned work rather than all constraints to planned work.4. Nesting the provision for T.O.'s to develop minimum vegetation to conductor clearances that ensure MVCDs are never violated within a general requirement to specify maintenance strategies. This needs to be a clear stand alone clearance requirement similar to the existing Clearance 2.
BC Transmission Corporation	V2 Does not maintain or improve overall reliability	This is a vegetation outage standard not a vegetation management standard. It will do nothing to improve the quality of vegetation maangement programs in North America
Northeast Power Coordinating Council--RSC	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. In some respects the Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to

Organization	Does or Does Not	Question 17 Comment
		mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of its employees and ensure that capable individuals perform their vegetation management functions.
Independent Electricity System Operator	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.

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ISO New England Inc.	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons: 1) eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) Eliminating the reporting of Category 3 sustained outages will lead to less effort by the TO's to mitigate danger tree exposure where the TO's property rights allow. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
Hydro-Quebec TransEnergie (HQT)	V2 Does not maintain or improve overall reliability	V2 will not improve reliability for the following reasons:. Eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance

Organization	Does or Does Not	Question 17 Comment
		(MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. This will lead to diminished reliability. The Standard does help maintain or improve overall reliability since the requirements for a TVMP are clearly addressed including inspection cycles, responses to imminent threats, and documentation requirements. Also, the fact that real time encroachments are considered violations will make utilities more likely to use LIDAR (radar) and other technology without the fear of discovery of an encroachment violation of a condition that has not occurred. This will result in earlier detection of potential problems and will increase reliability. Even though the Clearance 1 value is being eliminated from the Standard, operating specifications will still govern the way a utility handles its clearances as is currently done. We do agree, however, that landowners and local regulators may want utilities to reduce operational clearance levels based on the MVCD listed in the Standard, but the utility must properly communicate the reasoning behind achieving greater clearances as per their TVMP. We do not believe that eliminating the reporting of Category 3 sustained outages will lead to less effort to mitigate danger tree exposure since all transmission outages are sensitive to a Transmission Owner and must be addressed appropriately at multiple levels within the company as well as with other regulatory agencies in some cases. Removing the qualifications requirement may initially lead to Transmission Owners employing less qualified employees and contractors but there needs to be some level of flexibility that will allow for a larger candidate pool or temporary support since individuals with specialized training are not always readily available. The Transmission Owner should be solely responsible for determining the abilities and training needs of their employees and ensure that capable individuals perform their vegetation management functions.
Hydro One Networks inc.	V2 Does not maintain or improve overall reliability	V2 will not necessarily improve reliability for the following reasons: 1) eliminating Clearance 1 will be detrimental to reliability. The determination of Clearance 1 is an important exercise for the TO to better understand the dynamics of conductor movement and vegetative growth. This required analysis should lead to development of a more informed vegetation management program. Clearance 1 also gives the TO leverage with landowners and local regulators to achieve the necessary operational clearances. If the only required clearance is the R4 Minimum Vegetation Clearance Distance (MCVD), landowners and local regulators will push the utility to maintain a clearance close to the MVCD. 2) Eliminating the reporting of Category 3 sustained outages will lead to less effort by the TOs to mitigate danger tree exposure where the TOs property rights allow. This might lead to diminished reliability.
ISO/RTO Council	V2 Does not maintain or improve overall reliability	The SRC believes the change from Reliability Coordinator to Planning Coordinator and the inclusion of specific sub 200kv facilities maintains but does not improve the reliability effectiveness of this standard over Version 1. The removal of the subrequirements R10.1 and R10.2 in Version 1 and the

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		new R10 applicable to PCs is appropriate.

18. Besides the comments you have already provided for the preceding questions, do you have further suggestions for improving this standard? If so, please elaborate.

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Salt River Project	- R4: Recommend changing the word “Minimum” in “Minimum Vegetation Clearance Distances” to “Critical” (same with M4) - Footnote #4 (page 5 of 15): Recommend adding “microburst” (after storm) - Footnote #5 (page 5 of 15): Recommend addi
Xcel Energy	(a) The comments made above regarding the Requirement Sections of FAC-003-2 would need to be followed through in the Measure Sections of the standard.(b) Compliance Section 1.5 â— 1b, the word “but” needs to be replaced with the word “which.” (c) Attachment 1 needs to be renamed “Critical Clearance Distances” as discussed above in number 4.(d) We understand the drafting team’s intent, when referring to “applicable lines”, is to encompass all 3 items under Facilities in the Applicability section. Yet it is not clear as presently worded. Please clarify this in the next draft.(e) In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
Hydro One Networks inc.	(a) The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.(b) In the applicability Section, Facilities (4.2.1 in the clean version) we suggest to explicitly indicate that the standard applies to BES facilities only, to read as follows:BES transmission lines (“applicable lines”) operated at 200 kV or higher, and BES transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to this standard including but not limited to those that cross lands owned by federal, state, provincial, public, private, or tribal entities.
FirstEnergy Corp	1. Applicability of the standard with regard to Line Ratings - Regarding the phrase "throughout its operating range under rated conditions" in Req. R1, and also regarding the phrase "operating between no-load and their Rating" in Req. R4, R5, and R6, we feel that "rated conditions" and "Rating" is ambiguous. FE interprets the intent to reflect the maximum conductor thermal rating used in determining maximum sag conditions. We ask the SDT to confirm or clarify our interpretation. 2. Related to our comments in Question 10, section 4.2.2 should be revised to state that sub-200kV lines designated by the PC are subject to this standard 12 months after the Transmission Owner HAS RECEIVED the list from the PC.3. Changes may be needed to the Technical Ref. document based on changes to the standard per our previous comments. Also, on pg. 32 of the ref. document it shows a "high" VRF for Req. R6, but this should be "Medium". Lastly, on pg. 39 of the ref. document it references Part 11.3 which should say 1.1.3.4. Correct the misspelled word "Federal" in section 4.2.1.5. Compliance section 1.5 regarding

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	Categories, "Category 4" should be "Category 3". The footnote 7 is not needed and we suggest the team simply renumber the category list to be 1A, 1B, 2 and 3. Or, FE would support a renumbering of 1, 2, 3 and 4. The list should not skip or omit a category number.6. FE recommends that the SDT reconsider use of the term ‘applicable lines’ in the revised draft Standard. While applicability of the standard is already described, use of this term in specific requirements could suggest that there may be lines that are otherwise subject to requirements of the standard and only ‘applicable lines’ are addressed in some requirements. Therefore, we suggest removing the repeated use of the term "applicable lines" throughout the standard because it should be understood as those addressed in the "Applicability" section A4.2.. 7. Presently, the draft FAC-003-2 text includes a footnote stating that ANSI A300 standard for tree care operations is considered an industry best practice. FE recommends that this reference should not be included in the Standard. Since the ANSI standard would not provide certain obligations or requirements, it is not necessary to be included in the NERC Standard (See definition of Reliability Standard, Standards Development Procedure, p. 6). Rather, it should be included in a supporting document as a reference, as provided by the Standards Development Procedure (p. 34).
Entergy Services, Inc	A) The definition of Active Transmission Line Right of Way in the White Paper contains several examples of “inactive or unused” portions of corridors which are not contained in the definition in the standard. We suggest the examples contained in the White Paper are also included in the definition contained in the standard. Examples of something, the “corridor” in this case, helps clarify one’s understanding of “corridor”. The method is used in every dictionary. Therefore, we suggest adding the following to the definition in the standard:”Examples of inactive or unused portions of corridors include:1) The portions of the right of way acquired to accommodate future facilities. Power plant exits are examples where large rights of way are obtained for maximum corridor utilization and may currently have fewer lines constructed.2) The portion of the right of way where corridor edge zones (i.e., buffer zones) are provided for vegetation to exist.3) The portions of the right of way where double-circuit structures are installed but only one circuit is currently strung with conductors.4) Portions of the right of way with deactivated transmission lines that are unavailable for service.”B) Section 4.2 Facilities contains 3 subparts describing the facilities to which this standard applies. We suggest adding a fourth subpart from the White Paper which describes facilities to which this standard does not apply. Adding this fourth subpart will eliminate the need for future Interpretations and/or revisions to this standard. Please add to section 4.2 Facilities the following from the last paragraph of page 8 of the White Paper:”4.2.4 This standard does not apply to line sections inside the electric station or substation fence, other boundary of an electric station or substation, or underground lines.”C) The terms “imminent threat” and “vegetation imminent threat” are used in the standard. We suggest “vegetation imminent threat” be used in all locations of the standard.D) Standard R1.6 uses the term “never violated” which we believe requires 100% compliance and is too rigid a requirement given the propensity of hurricanes, tornados, and other weather conditions that cause debris to possibly broach the clearances contained in Table 1 Attachment 1. We suggest replacing “never violated” with “not violated during rated operating conditions and normal weather conditions.”E) R5, R6 and R8 contain 2 bullet items while the second bullet item in those requirements is not contained in R7. We suggest adding the second bullet item to R7:”Sustained Outages of applicable lines that result from human or animal activity.5”
MRO NERC Standards Review	A. In FAC-003-1 a self reportable violation could occur at any time vegetation was within, had previously been, or had passed through (fall in) the Clearance 2 zone. In FAC-003-2, this is reportable only if observed in real time. Under FAC-003-1, a tree

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Subcommittee	that was causing instantaneous operations of the line either through wind or loading would be a reportable violation of the Clearance 2 zone when found later during a patrol, even though the clearance now was well outside of the Clearance 2 zone. In FAC-003-2, a self reportable violation would be required only if the tree was observed, in real time, to be in the MVCD.B. Perhaps there should be a statement in FAC-003-2 that is explicit that the TO will manage its ROW to its "full and legal rights".C. The comments made above regarding the Requirement Sections of FAC-003-2 would need to be followed through in the Measure Sections of the standard.D. Compliance Section 1.5 Category 1B(“Grow-ins: Sustained Outages caused by vegetation growing into applicable lines but are not identified as an element of an IROL (or Major WECC Transfer Path) by vegetation inside and/or outside of the Active Transmission Line ROW”), the word “but” needs to be replaced with the word “which.” E. Attachment 1 needs to be renamed “Critical Clearance Distances” as discussed above in Question 4b.F. General comment to entire standard: Remove the repeated use of the term “applicable lines” throughout the revised standard. It should be understood as those addressed in the “Applicability” section A4.2.G. In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
Utility Arborist Association	As the industry’s leading science and educational organization, the UAA urges the standards drafting team to incorporate provisions that will encourage and compel all utilities to utilize proven vegetation management techniques and practices. We advocate for adequate and appropriate training, adherence to applicable A300 standards, and a clear, consistent, science-based approach to effective vegetation management across North America. ANSI A300 has the flexibility to adjust to local conditions, so there is no reason to not require it’s implementation. We also feel that it is appropriate to expect each utility to have a qualified person on staff (or in a full or part time contracted position) who fully understands proper utlity vegetation maangment. We believe the requirements of qualified people, and adherence to best practices, should be a part of this standard. Further, it is important to recognize the impacts of not directly referencing qualifications and best management standards (A300, etc) in this standard. Now that clearance 1 (in FAC-003 version 1) has been removed, there will likely be more incidents where land agencies, local governments or individuals will attempt to force their own interpretation of what is correct on the utility. In these cases the utility should be able to point to specific references in the proposed standard which will clearly identify what needs to be done (such as the practices described in A300). The utilities should also be able to point to specific references in the standard that establish them as the true authority on the required scope of work (particularly when they are liable for any failure). A specific reference to qualified employees and adherence to A300 will enable the utilities to better control their own ROW’s and should be included in this version of FAC-003.Finally, we believe that the regulators, and other entities who shall be overseeing compliance with this standard, should have an equal understanding of utility vegetation management and compliance as the utilities charged with complying with FAC-003-02. In order to raise the understanding of vegetation managment on the part of vegetation management auditors, the UAA is developing training specifically for them. Our intent is to offer a program that will be available to utilities and compliance auditors that will lead to a consistent and informed understanding of vegetation management and its legal and regulatory requirements. Thank you for the opportunity to

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	comment on this very important regulation and the UAA stands ready to assist the standards drafting team in any way we can.
Consolidated Edison Company of New York Inc.	CECONY recommends 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 and help maintain a higher level of reliability. This is currently done at the state level (in New York) and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well.
Edison Electric Institute	EEI has two additional recommendations for consideration by the SDT. First, the draft revised Standard stated purpose is to 'avoid vegetation related outages that could lead to Cascading.' To better align the Standard with the direction provided by Order No. 693 as well as the content of the revised draft Standard, EEI recommends that the SDT consider revising the purpose statement to read: 'To avoid vegetation-related Sustained Outages of transmission lines.'Second, EEI agrees with the intent of including events that would define exceptions for requirements to comply with FAC-003. To assist in reducing ambiguity and as an alternative to the approach in the draft Standard of using footnotes, EEI recommends that the SDT consider adding a generic exceptions statement in the applicability section more specifically stating that companies will not be subject to compliance requirements to the extent that events or circumstances beyond their control limit or prevent their abilities to perform. Here's one example:Compliance with this Standard will not apply should there exist an occurrence, non-occurrence, or other set of circumstances that are beyond the reasonable control of a Registered Entity subject to this Reliability Standard, and are not caused by the fault or negligence of the Registered Entity, including acts of God, strike, flood, drought, earthquake, storm, fire, hurricane, tornado, landslides, logging activities, animals severing trees, lightning, epidemic, war, riot, civil disturbance, sabotage, vandalism, terrorism, or action or inaction by any Governmental Authority or individual that restricts or prevents performance to comply with this Reliability Standard. Should the SDT choose to not add a specific exceptions statement, EEI encourages additional specificity in the footnotes.
Transmission Owner	FPL is in support of the changes made to the Purpose Statement. The purpose should be further clarified. FPL Suggests the following wording:To improve the reliability of applicable electric transmission facilities by preventing those vegetation related outages within active ROW that could lead to Cascading.FPL agrees with the changes in R9 and indicated that in Question 9, however, FPL sees a need for an exemption due to disasters (natural or manmade). During the hurricane seasons of 2004 and 2005 most utilities in the east and southeast were either directly or indirectly affected by the hurricanes occurring in that time period (including named storms. It was in the National interest that those not directly effected respond to requests for mutual aid from those utilities that were. Conversely, those affected had to restore their systems. Annual Work Plans were delayed or changed. An exemption or mechanism needs to be in place to allow utilities to respond with out violating the standard.
American Transmission Company	General comment to entire standard: Remove the repeated use of the term "applicable lines" throughout the revised standard. It should be understood as those addressed in the "Applicability" section A4.2.Also, ATC supports the deletion of footnote #2 to R1.1 regarding ANSI A300. Since the ANSI standard would not provide certain obligations or requirements, it is not necessary to be included in the NERC Standard. (See definition of Reliability Standard, Standards Development Procedure, p. 6) Rather,

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	it should be included in a supporting document as a reference, as provided by the Standards Development Procedure (p. 34)
Oncor Electric Delivery	Having a binary system for R4, 5, 6, 7, and 8 creates a one size fits all approach. The SDT should consider allowing for some normalizing of events / sustained outages per metric considering the number of applicable miles to allow a range of VSL's to be applied.
CenterPoint Energy	Improvements to Standard1. Revise the Purpose statement to "preventing vegetation related outages" and delete "that could lead to Cascading" since Cascading is not referenced anywhere else within the Standard.2. Within R1.6, substitute "practices" for "strategies" as a more actionable word.3. R1.2 and R3 should use the same wording when referring to the frequency of Vegetation Inspections.4. Within M1.6, substitute "practices" for "strategies" as a more actionable word.Improvements to Technical Reference 1. Revise the statement on page 9 to read as follows, "It is not intended to prevent customer outages from occurring due to tree contact with all transmission lines and voltages; however, the Standard is not intended to dissuade best utility practice regarding vegetation management for transmission lines that fall outside the Standard." The Technical Reference is a public document, and thus should be careful to mention best management practices, public safety, and hazard avoidance whenever applicable. Allowing trees to grow near transmission lines at any voltage is a public safety hazard.2. In the Wire-Border Zone section on page 15, CenterPoint Energy recommends revising this sentence as follows, "The wire zone is the section of a utility transmission right of way directly under the wires and extending outward a sufficient distance to allow for movement of the conductors", which deletes the phrase "about 10 feet on each side". The specific 10' distance is misleading where rights of way are purchased without ownership of a border zone, and it may be misleading to the public. CenterPoint Energy has not historically purchased a border zone, and the wire zone equates to the legal limits of our rights of way.The paragraphs on page 15 that start, "One way...", and "In areas where...", should be deleted because they may mislead the public by not taking into account all the needs to remove trees such as access below the lines and possible reconductoring or rebuilding of lines that change the transmission line profile and thus impact the need to remove tall trees in any instance. The prior statement that starts, "Although the wire-border zone..." is sufficient to introduce flexibility in practices.3. In the Selecting a Maintenance Strategy section on page 25, CenterPoint Energy recommends deleting the paragraph that starts, "If faced with...". It should be deleted because it may mislead the public to believing that granting exceptions for trees is a common practice and should be pursued. It does not take into account all the needs to remove trees such as access below the lines and possible reconductoring or rebuilding of lines that change the transmission line profile and thus impact the need to remove tall trees in any instance. It is also not necessary to the example.4. The third bullet under R4 on page 30 has an extra word, "Brief", that is not in the Standard itself.5. R6 quoted on page 32 has an incorrect Violation Risk Factor of "High" instead of "Medium".
Idaho Power Company	In the definition of terms remove 'intended for other facilities' from the definition for Active Transmission Line Right of Way. In the definition of Vegetation, remove ' considering the current location of the conductor and other possible locations of the conductor due to sag and sway for rated conditions' since this is covered in the Standards section.In the measures section, remove 'neighboring Planning Coordinators' from M10 since a neighbor may have different views as to which sub-200kV lines

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	are subject to Standard R10
SCE&G	N/A
WECC RC	NO
National Grid	No additional comments.
American Electric Power	No additional questions at this time.
PacifiCorp	None
NRECA - National Rural Electric Cooperative Association	NRECA on behalf of its members would like to thank the drafting team for its efforts in addressing cooperative concerns from the previous draft of FAC-003-2. In addition, it is important for the drafting team to incorporate the recommendations of the Generator Requirements at the Transmission Interface Ad Hoc Group (GOTO Team) regarding the implications of this standard for the transmission facilities designated as Generator Interconnection Facilities (GIFs). The specific recommendations NRECA supports are; the sole use of GIFs should not cause the registration of entities as Transmission Owners and Transmission Operators, clarifying requirements for GIFs, adding new requirements to make expectations clear for these facility types and working with the GOTO Team to incorporate any new definitions in the NERC Glossary of terms to clarify requirements of this standard.
Orange and Rockland Utilities, Inc.	ORU recommends 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 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 would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well.
Associated Electric Cooperative, Inc.	Paragraph A.4.2.1 - Associated Electric Cooperative Inc assumes the Standard Drafting Team's intent is for the standard to apply, without exception, to all transmission lines operated at 200 kV or higher and to all transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to the standard. To this end, AECI believes the list of land ownerships included in A.4.2.1 detracts from, rather than adds to, the clarity of the paragraph. It is suggested the paragraph be revised to something like, "All transmission lines ("applicable lines") operated at 200 kV or higher, and all transmission lines operated below 200 kV designated by the Planning Coordinator as being subject to this standard."Paragraph D.1.5 - This paragraph clearly requires Transmission Owners to provide periodic reports to the Regional Entity of Sustained Outages occurring on applicable lines that are caused by vegetation. As such, it should be included in the Requirements section of the standard. Associated Electric Cooperative Inc. does not disagree with the intent of the paragraph, only its location within the

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	standard.
Progress Energy Carolinas, Inc.	PEC recommends that the ANSI A300 footnote #2 to R1.1 be removed and included in supporting documentation (the Technical Reference document - “White Paper”).
Southern California Edison Company	SCE appreciates the great amount of time and effort expended by the Drafting Team on the FAC-003-2 Reliability Standard.
Entegra Power Group LLC	See Question 14 comments
Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Kissimmee Utility Authority	Specify an interim corrective action process for use when theTransmission Owner is temporarily constrained from performingvegetation maintenance as planned.
Vegetation Management Team	The “methods ... to control” in R1.1, the annual work plan in R1.3, and the “maintenance strategies” in R1.6 seem to refer to the same actions but require the TO to address them separately in the TVMP. This needs to be clarified or consolidated.
Central Maine Power an Energy East Company	The clearance 2 defined in FAC 003 1 was a useful tool for transmission owners to manage rights of ways to a robust standard rather than a minimum standard. This language should be included in the TVMP requirement (R1). Suggested language "The TVMP must define a clearance two". The standard would only require this distance be included as part of each T.O's plan, and would eliminate the fill in the blank concept.Suggest that standard note that qualif1ed vegetation managers are recommended to manage the V.M. program.FAC 003 2 should retain the reference to ANSI A300.
Hydro-Quebec TransEnergie (HQT)	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended 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 and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.We reiterate the need to change the language used in the purpose of the Standard as per our answer to Q10; if not, we would appreciate to know the SDT rational.

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Independent Electricity System Operator	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended 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 and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.
ISO New England Inc.	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended 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 and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.
Northeast Power Coordinating Council--RSC	The inclusion of a detailed description of ANSI A300 contains a level of detail greater than what should be included in the standard. A simple reference to the ANSI standard would be more than sufficient to provide an example of what may be included in a TVMP, without appearing to dictate specific vegetation management practices that may or may not be available or practical for all Transmission Owners across North America.It is recommended 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 and help maintain a higher level of reliability. This is currently done at the state level (in New York), and the revised wording in the Federal Standard would ensure consistency industry-wide and avoid confusion. A standard definition for the term incompatible would be required to avoid misuse of the term as well. Editorial comments--the “1” after “federal” in the first bullet under “Facilities” in the “Applicability” section should be a superscript to indicate the footnote. The text that a footnote refers to should appear at the bottom of the page it is used on, or at a common location, not on different pages.

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Southern Company	The new format for the standard moves some requirements from the compliance section (i.e. outage reporting) to additional compliance information. Does this remove the outage reporting requirement from the CMEP? If not, how will it be monitored?
ReliabilityFirst Corporation	The only comment I have is in Facilities section, in the first bullet. I do not see need for adding all the verbiage (including but not limited to those that cross lands owned by federal1, state, provincial, public, private, or tribal entities) after “designated by the Planning Coordinator”.
Superintendent Transmission Maintenance	The white paper could further explain the process by which the planning coordinator and utilities identify sub-200kV lines to be included in the standard. Clarify the definition of an active transmission ROW.
Manitoba Hydro	the wording of requirement 1.5, last word should be changed from "planned" to "required" as one could change the plan based on land deal negotiations for example, or site specific engineering calculations, but at least the minimum requirements to maintain the vegetation must be met.In version 1 of FAC-003, a sustained outage caused by vegetation within the ROW likely results in a single violation. However, the latest draft of version 2 is written such that the same sustained outage would result in the violation of at least 2, if not 3, requirements. This could quickly ratchet up the penalty amount by 3-4 times. We do not feel that this is reasonable, and recommend that modifications be made to remove double or triple jeopardy circumstances.
SERC Vegetation Managment Sub-committee (VMS)	There are certain lines, not owned by Transmission Owners (TO’s) that should be covered by this standard. These include facilities owned by DP’s and GO’s that are not registered as TO’s. This should be addressed via the Standard’s applicability section and not via registration.
Bonneville Power Administration	There are several inconsistencies throughout the document regarding the way Attachments are referred to. The lines are referred to in many different ways - real-time, no load, etc. ??? Standard is a little difficult to follow. The term “sway” is not a technical term, suggest using “swing” or “blow out”.
North Carolina Electric Membership Corporation	Yes. There are certain facilities, not owned by Transmission Owners (TO’s) that should be covered by this standard. These include facilities owned by Distribution Provider’s (DP’s) and Generation Owner’s (GO’s) that are NOT registered as TO’s. In the last draft, several entities provided comments to the SDT about GO’s and DP’s who own such interconnection facilities to connect their generation and load to the transmission system. We make a plea to the SDT to reconsider those comments such as those provided by SERC Compliance Staff. As the standard currently exists today, it forces entities that have such interconnection facilities to be registered as a TO’s regardless of the length of the facility used for interconnection (50 feet, 0.50 miles or 50 miles). These additional facilities should be captured via the Standard’s applicability section and not via registration, thus making the entity subject only to the FAC-003 standard and not to all TO standards. Also, we respectfully request that the SDT provide additional guidance in the standard about length of interconnection facilities before the standard is applicable to such facilities. One suggestion has been offered in the GOTO Team forum ad we repeat here for the benefit of the SDT: Only those Generator Interconnection Facilities above 200kv which extend more than one mile from the Generator

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	Owner property boundary should be assigned applicability for FAC-003-1. A clarification may be needed to provide that those Generator Interconnection Facilities which are located entirely on Generator Owner property should not be applicable.We would also suggest the same guidance be provided for tap lines and radials owned by DPs when these taps or radial are short distances and are within DP property where there would be no gaps. Without this guidance or clarification, then it is left to each Regional Entity to apply their own opinion which may result in inconsistency in enforcing the standard.