Consideration of Comments on Fourth Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the fourth draft of the TPL-001-1 standard. This standard was posted for a 30-day public comment period from September 16, 2009 through October 16, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 67 sets of comments, including comments from more than 180 different people from over 85 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Assess-Transmission-Future-Needs.html

Due to industry comments, the SDT has made the following clarifying changes;

- Definition: Non-Consequential Load Loss
- Requirement R1, part 1.1.6
- Requirement R2, parts 2.1.3, 2.1.4, 2.1.5, 2.3, 2.4, 2.4.3 bullet #3, 2.5, 2.6.2, 2.7, 2.7.1 bullets #1 and #4, and 2.9
- Requirement R3, parts 3.3, 3.3.2, 3.3.3 and 3.6
- Requirement R4, parts 4.1.2, 4.3, and 4.5
- Requirement R5
- Requirement R6
- Requirement R8
- Measures M1, M6, M7, and M8
- Table 1, Header notes 'b', 'f', and 'g', footnotes 1, 2, 3, 5, and 7
- Data retention for Requirement R1, R3, R5, R6, and R8
- VSLs for Requirements R1 and R8

While the changes cited address the vast majority of comments received, the following minority viewpoints remain:

- Continued concern over the value of the "raising the bar" for EHV Facilities
- Continued concern with excessive study or documentation requirements
- Concerns that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005)

In addition, several commenters requested that workshops be conducted to explain the details of the new standard. To date, the SDT has conducted 3 webinars and presented the standard at 2 different NERC standards workshops. In addition, the NERC Planning Committee has had 2 presentations and several regional entities requested and received presentations from SDT members. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions.

The SDT does not feel that this standard requires field testing prior to ballot. The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — 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	Bob Cummings	TIS	X	X		X	X				X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eric M. Mortenson (Chair)	Exelon Energy Delivery		
2.	Mark Byrd (Vice Chair)	Progress Energy Carolinas		
3.	Gary Brownfield	Ameren		
4.	Kenneth A. Donohoo	Oncor Electric Delivery		
5.	Patricia E. Metro	National Rural Electric Cooperative Association		
6.	I. Paul McCurley	National Rural Electric Cooperative Association		
7.	Scott M. Helyer	Tenaska, Inc.		
8.	Israel Melendez	Constellation Energy Commodities Group		
9.	Hari Singh	Siemens Power Technologies International		8
10.	John M. Simonelli	ISO New England, Inc.		2
11.	Digaunto Chatterjee	MISO		2
12.	Steve Corey	New York Independent System Operator		2
13.	Dana Walters	National Grid USA	NPCC	9
14.	Hai Quoc Le	Northeast Power Coordinating Council, Inc.	NPCC	9

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

15.	Bill Harm	PJM	RFC	9
16.	Wenchun Zhu	American Transmission Company	MRO	9
17.	Salva R. Andiappan	Midwest Reliability Organization	MRO	9
18.	Hector Sanchez	Florida Power & Light Co.	FRCC	9
19.	Pedro Modia	Midwest Reliability Organization	FRCC	9
20.	W. Perry Stowe	Southern Company Transmission Company	SERC	9
21.	Jay Caspary	Southwest Power Pool	SPP	9
22.	Wesley Woitt	CenterPoint Energy	ERCOT	9
23.	David Franklin	Southern California Edison Company	WECC	9
24.	Branden Sudduth	Western Electricity Coordinating Council	WECC	9
25.	Other Observers and NERC Staff			

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Ben Li	SRC of ISO/RTO (Comments submitted by Mark Westendorf of Midwest ISO on behalf of Ben Li)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ben Li	IESO	NPCC	2
2.	Bill Phillips	MISO	MRO	2
3.	Mark Thompson	AESO	WECC	2
4.	Charles Yeung	SPP	SPP	2
5.	Steve Myers	ERCOT	ERCOT	2
6.	Patrick Brown	PJM	RFC	2
7.	James Castle	NYISO	NPCC	2

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

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

	Additional Member	Additional Organization	Region	Segment Selection
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
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 United 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

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Co.	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	Scott Goodwin	Midwest Independent Transmission System Operator	SERC	1
4.	James Manning	North Carolina Electric Membership Corporation	SERC	3
5.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
6.	Pat Huntley	SERC Reliability Corporation	SERC	10
7.	Bob Jones	Southern Company Services, Inc.-Trans	SERC	1
8.	David Marler	Tenessee Valley Authority	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Bob Cummings (Coordinator)	NERC System Protection and Control Subcommittee (SPCS)	X	X		X	X				X	X

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	John L. Ciufo	Hydro One, Inc	NPCC	1
2.	Jonathan Sykes	PG&E	WECC	1
3.	Michael McDonald	Ameren Services Company	SERC	1
4.	William J. Miller	Exelon Corporation	RFC	1
5.	Josh Wooten	Tennessee Valley Authority	SERC	9
6.	Sungsoo Kim	Ontario Power Generation Inc	NPCC	5
7.	Joe T. Uchiyama	U.S. Bureau of Reclamation	WECC	5
8.	Charles W. Rogers	Consumers Energy	RFC	4
9.	Joseph M Burdis	PJM Interconnection, L.L.C.	RFC	2
10.	Jim Ingleson	New York Independent System Operator	NPCC	2
11.	Bryan J Gwyn	National Grid	NPCC	1, 10
12.	Henry G Miller	AEP Service Corp	RFC	1, 10
13.	Richard P. Quest	Xcel Energy	MRO	1, 10
14.	John Mulhausen	Florida Power & Light Co	FRCC	1, 10
15.	Philip Winston	Georgia Power Company	SERC	10, 1
16.	Dean Sikes	Cleco Power LLC	SPP	1, 10
17.	Samuel Francis	Oncor Electric Delivery	ERCOT	1, 10
18.	Baj Agrawal	Arizona Public Service Co	WECC	1, 10
19.	Thomas Wiedman	Wiedman Power System Consulting Ltd		NA
20.	Robert W. Cummings	NERC		NA
21.	Philip J Tatro	NERC		NA

				1	2	3	4	5	6	7	8	9	10
6.	Group	W. R. Schoneck	Florida Power and Light	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaffer		FRCC	
2.	Pedro Modia		FRCC	
3.	Carlos Candelaria		FRCC	
4.	Kiko Barredo		FRCC	

				1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates PHI	X		X		X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Mitchell	Delmarva Power & Light Co.	RFC	1
2.	John Radman	Potomac Electric Power Co.	RFC	1
3.	Carl Kinsley	Atlantic City Electric	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Rick Foster	SERC Dynamics Review Subcommittee (DRS)	X								X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
7.	Jonathan Glidewell	Southern Company Services, Inc. - Trans	SERC	1
8.	Robbie Bottoms	Tennessee Valley Authority	SERC	1, 9
9.	Tom Cain	Tennessee Valley Authority	SERC	1, 9
10.	Herb Schrayshuen	SERC Reliability Corporation	SERC	10
11.	Carter Edge	SERC Reliability Corporation	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Steve Hill	Modesto Irrigation District Transmission Planning	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Spencer Tacke	MID	WECC	NA

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ed Baznik	FE	RFC	1
2.	John Stephens	FE	RFC	1
3.	Jeff Mackauer	FE	RFC	1
4.	Carl Bridenbaugh	FE	RFC	1
5.	Sam Ciccone	FE		1, 3, 4, 6

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
11.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	BPA Transmission Planning	WECC	1
2.	Melvin Rodrigues	BPA Transmission Planning	WECC	1
3.	Chuck Matthews	BPA Transmission Planning	WECC	1
4.	Kyle Kohne	BPA Transmission Planning	WECC	1
5.	Larry Furumasu	BPA Transmission Planning	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	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 Address	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Frank Gaffney, Regulatory Compliance Officer	Florida Municipal Power Agency, and its Member Cities, Lakeland Electric and Fort Pierce Utility Authority	X		X	X	X	X	X			
14.	Individual	Travis Hyde	Oklahoma Gas & Electric	X									
15.	Individual	Hugh Francis	Southern Company	X		X		X					
16.	Individual	Richard	FRCC Transmission Working Group	X		X	X					X	X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
18.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X							
19.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
20.	Individual	Pete Jones	Puget Sound Energy, Inc.	X									
21.	Individual	Baj Agrawal	Arizona Public Service Co.	X		X		X					
22.	Individual	Jay Teixeira	ERCOT ISO		X								X
23.	Individual	Milorad Papic	Idaho Power	X									
24.	Individual	James Tucker	Deseret Power	X		X		X					
25.	Individual	Adam Menendez	Portland General Electric Co.	X		X		X	X				
26.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
27.	Individual	Tim Ponseti, VP	TVA System Planning	X									
28.	Individual	Brian Keel	SRP	X									
29.	Individual	Vishal Patel	Southern California Edison (SCE)	X		X		X					
30.	Individual	John Collins	Platte River Power Authority	X		X			X				
31.	Individual	Gordon Rawlings	British Columbia Transmission Corp	X	X								
32.	Individual	James Starling	SCE&G	X		X		X	X				
33.	Individual	Catherine Mathews	NorthWestern Energy	X		X		X					
34.	Individual	Dilip Mahendra	Sacramento Municipal Utility District	X		X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Thad Ness	American Electric Power	X		X		X	X				
36.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
37.	Individual	Terry Huval	Lafayette Utilities System										
38.	Individual	Jessica Rice	NV Energy	X									
39.	Individual	L. Earl Fair	Gainesville Regional Utilities	X		X		X					
40.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
41.	Individual	Michael Ayotte	ITC Holdings	X									
42.	Individual	John Pearson	ISO New England		X								
43.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
44.	Individual	Scott Goodwin	Midwest ISO		X								
45.	Individual	John Sullivan	Ameren	X		X		X	X				
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Robert H. Easton	Western Area Power Adm - RMR	X								X	
48.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
49.	Individual	Greg Campoli	NYISO		X								
50.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
51.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
52.	Individual	David M. Conroy	Central Maine Power Company	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
53.	Individual	Paul Rocha	CenterPoint Energy	X									
54.	Individual	Mark Byrd	Progress Energy Carolinas	X		X		X					
55.	Individual	Larry Brusseau	MAPP								X		
56.	Individual	Aaron Staley	Orlando Utilities Commission	X		X		X	X				
57.	Individual	Martin Bauer	US Bureau of Reclamation					X					
58.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
59.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
60.	Individual	David Wang	San Diego Gas & Electric Co	X									
61.	Individual	Dan Rochester	Independent Electricity System Operator		X								
62.	Individual	Jason Shaver	American Transmission Company	X									
63.	Individual	R. Peter Mackin	Utility System Efficiencies, Inc. (USE)										
64.	Individual	Mark Graham, on behalf of the Power System Planning Department	Tri-State Generation and Transmission Association	X		X		X	X				
65.	Individual	David Bradt	United Illuminating	X									
66.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
67.	Individual	Mark Kuras	PJM										

1. Requirement R1 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made several clarifying changes to Requirement R1, Measure M1, and to the VSLs for R1 based on industry comments.

Requirement R1, Part 1.1.6 has been clarified to reflect that this requirement may not be exclusively sources supplying load. As an example, Demand Side-Management (DSM) may be used.

The words "within its respective area" have been added after "that it is maintaining System models," to Measure M1 for additional clarification.

The words "responsible entity's" have been added after "OR The" under the Moderate and Severe VSLs for Requirement R1 for additional clarification as well.

R1, Part 1.1.6 - Resources (supply or demand side) required for Load

R3.3.3. Trip Transmission elements when relay loadability limits are exceeded

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

		sources, including items represented in the Corrective Action Plan.		

Organization	Comments for Question 1
ERCOT ISO	* This requirement seems to be embedding information that should be contained in the MOD standards. Does this present double jeopardy? This requirement, measurement, and VSL are all about maintaining models a MOD standard revision may need to be included or recommended to allow the focus of the TPL standard to be on transmission planning studies, not modeling. * Requirement 1.1.2 should read “all known outages of generation or transmission facilities with a duration of at least six months as appropriate for the timeframe represented by the particular model” * The moderate VSL category states “the System model did not use” this is confusing as the model does not do anything. It should contain the latest data. We also want to ensure this is not implying that the studies must use the latest data data changes continuously, and a study may never be complete if the data must be continuously updated. * Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall maintain System models for performing the studies needed to complete the required Planning Assessments. The models shall contain the latest data consistent with MOD-010 and MOD-012? "
Response: 1. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements in the TPL standard with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: “Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations.” 2. The SDT does not believe that the proposed language adds any clarity. No change made. 3. The SDT does not believe that the proposed language adds any clarity. No change made. The system models should be updated per MOD-010 & MOD-012. 4. Requirement R7 identifies the individual and joint responsibilities for performing required studies only. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
Bonneville Power Administration	: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.

Organization	Comments for Question 1
	For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NorthWestern Energy	As written R1.1.4, “Real and reactive Load forecasts”, could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to “ forecasted demand and power factor” to clarify that forecasting reactive load is not required. In R1.1.5 Change “Firm Transmission Service and Interchange” to “Firm Transmission Service or Interchange”. This way the requirement can be satisfied by either one or the other.
Deseret Power	Comments: R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Idaho Power	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 I suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Modesto Irrigation District Transmission Planning	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
NV Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases

Organization	Comments for Question 1
	where not all contractual arrangements are known.
Pacific Gas and Electric Co.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Puget Sound Energy, Inc.	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
San Diego Gas & Electric Co	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. R1.1.5 "firm transmission service agreements" should be removed the from the requirement. Firm transmission service agreements, "known" or otherwise, have no effect on reliable operation of the grid; power will flow where it wants, not where, or how, the firm transmission service agreement may specify. From a reliability perspective this information is of no use.
Southern California Edison (SCE)	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
SRP	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5 we suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.

Organization	Comments for Question 1
Western Area Power Adm - RMR	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. For R1.1.5, I suggest changing the wording from “Known commitments for Firm Transmission Service and Interchange” to “Known commitments for Firm Transmission Service or Interchange”. It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
Northeast Utilities	[R1.1.6] What is NERC’s definition of “Resources required to supply load”?[Add R1.1.7] The standard is referring to requirements for sensitivity and other issues without a reference to base cases. There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include a discussion as to whether or not generator forced outages are to be represented in the base cases. Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base cases. For some areas, their current practice is to include heavy system stresses in their base cases. It is unclear if this practice works within the purview of this standard. Therefore, it is recommended that each Region must have a document that defines what constitutes base case conditions.
Response: 1. “Resources required to supply load” is not a NERC defined term. “Facility” is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6** - Resources (supply or demand side) required for Load **2.** The SDT believes that “base case conditions” should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. Please note that Requirement R1, part 1.1.2 includes only known outages of generation with duration of at least 6 months. Requirement R1, part 1.1.5 includes known commitments for Firm Transmission Service and Interchange - while the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 can include varying expected transfers by a sufficient amount to stress the System. The Standard will leave it up to each Region to further define their own base case documentation if they desire to have such a document.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF’s previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
American Electric Power	Because the revised transmission planning standard now explicitly references short circuit analysis, we believe that there is a

Organization	Comments for Question 1
	need for a parallel MOD standard to establish requirements for short circuit modeling and for a corresponding reference under R1, just as there are references made in R1 to MOD-010 (power flow models) and MOD-012 (stability models) . We recognize that such a MOD standard will not be addressed as part of this project, but we request that the SDT pass this comment on to NERC Staff.
Response: NERC has committed that it will update the appropriate MOD standards after the TPL revisions are finalized. A note has already been made in the official NERC issues database for a revision to the MOD standards based on the changes to TPL.	
CenterPoint Energy	CenterPoint Energy appreciates the SDT's efforts in revising R1 and generally agrees with the requirement except for verbiage and sub-requirements relating to modeling future transmission system projects, including projects identified in Corrective Action Plans. Specifically, CenterPoint Energy recommends that the SDT revise R1 by deleting the text "including items represented in the Corrective Action Plan" and delete part 1.1.3 in its entirety. Certainly, it is appropriate to model some limited subset of future projects, including projects included in Corrective Action Plans, which are reasonably "firm" or "committed". In previous drafts, the SDT tried to incorporate language to capture that concept but apparently abandoned the idea in response to industry comments. However, it remains true that many future "planned" projects, including projects in Corrective Action Plans, are tentative in nature and have a high degree of uncertainty due to uncertainty in forecasted system conditions. Because of this reality, and the fact that models are intended to be useful for identifying what future projects might be necessary, CenterPoint Energy believes many transmission planning organizations do not and should not model any and all new planned transmission facilities tentatively identified based upon studies and assessments of previous system models. Once the System model is updated with previously contemplated transmission projects, it is problematic to determine in future studies whether or not those projects are still needed, which is contrary to the intent of updating the model. If CenterPoint Energy's recommended changes are made, Transmission Planners and Planning Coordinators would not be precluded from incorporating future projects into their System models in accordance with their established practice but they would not be required to inappropriately model any and all previously contemplated projects.
Response: The SDT believes that the Corrective Action Plans and Requirement R1, part 1.1.3 are being correctly used in this planning standard. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that systems can change over time which will result in some changes for the Corrective Action Plans. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL 001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Platte River Power Authority	Change R1.1.5 wording from "...Service and Interchange." to "...Service or Interchange."
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
ITC Holdings	Comments: These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out?

Organization	Comments for Question 1
	In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: 1. Requirement R1 is a modeling requirement which requires any expected operational Facilities to be modeled based on market and contractual obligations. 2. The SDT believes that the requirements under this standard do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations.	
FirstEnergy Corp	FirstEnergy believes the draft 4 version of requirement R1 is greatly improved over prior drafts. The team has correctly responded to industry stakeholders and arrived at an appropriate middle ground that should resolve most stakeholder concerns. The changes made in R1.1.2 stating modeling of known outages with a duration of 6-months or more helps clarify a requirement that was previous subjective and open for interpretation. The removal of the previously prescriptive "such as list" is also well received by FirstEnergy.Finally, the addition of the text "known commitments" in regards to Firm Transmission Service and Interchange resolves our prior concerns.
Gainesville Regional Utilities	I like the more simplified approach used in the requirement listing. As far as "using the latest data consistent with MOD-010 & MOD -012 data", I feel that unplanned or unknown system changes between the times when studies are actually ran for the long term planning process should not be an issue for any type of negative interpretation by a compliance auditor. I presently do not have a suggestion on how to guarantee such an understanding. Overall the revisions look good.
Tri-State Generation and Transmission Association	R1 - The changes to R1 seem good.
Response: Thank you for your comments.	
Utility System Efficiencies, Inc. (USE)	For R1.1.5 I suggest changing the wording from "Known commitments for Firm Transmission Service and Interchange" to "Known commitments for Firm Transmission Service or Interchange". It is difficult to distinguish between the two in future cases where not all contractual arrangements are known.
Response: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as	

Organization	Comments for Question 1
an example, then this fact should just be documented.	
Orlando Utilities Commission	In general I support all the changes from the prior revision. I especially like the clarification that outages of 6 months or longer need attention in planning studies. Several questions on the details: R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Is this requiring that models should always be current, updated for the slightest change, even between studies? Or just that models are kept up to date in a more practical application such as monthly, quarterly or before their use in a study?R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added, but does not require that they are, is this the correct understanding? -R1 requires the model to represent Known Commitments for Firm Transmission Service, and also references load forecasts. The application of this requirement seems to be that the model should be based on the load forecast and include the appropriate known firm transmission service for the amount that would be used at that forecast level?
Response: 1. Yes, your understanding is correct. Thank you for your comments. 2. The SDT agrees that the model should be based on the load forecast. The SDT believes that the appropriate known Firm Transmission Service should also be included. Please note that Requirement R1, part 1.1.6 has been clarified to state that supply or demand side can be used for supplying Load. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load	
MAPP	1. It would be helpful to identify the relationship expected between the PC and the TP. It looks as if both PC and TP are expected to maintain the same models. We need to avoid duplicated effort. Does the standard really apply to "both", or could it be "either"? 2. Is a Corrective Action Plan being used correctly throughout this standard? It seems like the specifics of a CAP aren't appropriate for future planning years. Planning studies are only estimates of expected system growth, and the apparent problem might turn out to be different, or not exist at all. Will compliance people start going "over the top" examining CAPs? The current practice of summarizing possible problems in future years and identifying possible solutions seems more appropriate than pinning entities down to Corrective Action Plans. Corrective Action Plans seem appropriate only for the Operating horizon.R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. 3. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. 4. M1 We recommend the bolded words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"? What does it mean to have a hardcopy of a system model? 5. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models

Organization	Comments for Question 1
	when for P1 events are simulated, as specified in R2.1.3. We suggest that the intent can be more simply handled by stating in R2.1.3 that known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur. 6. R1.1.3 Add the qualification of "for the years defined in R2". 7. R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear.
Response: 1. The SDT believes that both the Transmission Planner and Planning Coordinator have this modeling responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required. 2. The SDT believes that the Corrective Action Plans are being correctly used in this planning standard and is appropriate for all planning years. Please note that there are a variety of associated actions that can be used to achieve required System performance as noted in Requirement R2, part 2.7.1. The SDT agrees that Systems can change over time which will result in some changes for the Corrective Action Plans. The SDT cannot speculate on auditor's actions. The SDT is not trying to "pin down" entities in regards to these plans but to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. The SDT believes that "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. 3. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required. 4. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1 5. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to insure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 6. The SDT does not believe that the proposed language adds any clarity. No change made. 7. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load	
MidAmerican Energy Company	MidAmerican recommends the words in all caps be added to M1 to indicate that each responsible entity must provide evidence

<table>
<tr><th>Organization</th><th>Comments for Question 1</th></tr>
<tr><td></td><td>that “it is maintaining System models WITHIN ITS RESPECTIVE AREA, using the latest”?</td></tr>
<tr><td colspan="2">Response: The SDT agrees that adding “within its respective area” would help clarify this measure. The SDT has modified Measure M1 to include this new language.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.</td></tr>
<tr><td>Florida Power and Light</td><td>No entity that we know of provides specific reactive load forecasts. From the auditor’s perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all “Known commitments for Firm Transmission Service and Interchange”. The SDT needs to add “that are expected to be utilized.” to the requirement.

1.1.6 Recommend changing to “Resources expected to supply Load”The requirements seem to imply a difference in certainty between “known” and “planned”. Known implies certainty, where planned implies less certainty, as in an assumption. Planned things can change but known things are much less subject to change. The drafting team should clarify the distinction between the two terms or be more specific in the requirement as to what is expected rather than leaving it for interpretation as to meaning and intent.</td></tr>
<tr><td colspan="2">Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT believes that the existing language is adequate. The SDT believes that all known commitments for Firm Transmission Service and Interchange should be modeled. The SDT does not believe that the proposed language adds any clarity. No change made.

2. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. Please note that the word “required” is used in Requirement R1, part 1.1.6.

R1, part 1.1.6 - Resources (supply or demand side) required for Load</td></tr>
<tr><td>Independent Electricity System Operator</td><td>Please explain what is envisaged by the phrase “and shall represent projected System conditions.” that is not already covered by the list in Requirement R1, part 1.1. We suggest removing the phrase.

We do not have any comments on the, measure, VRF and Time Horizon.

Consistent with our comment above, we believe that the 2nd condition under the Severe VSL is (a) vague, and (b) already covered by parts 1.1.1 to 1.1.6. This second condition is not needed.</td></tr>
<tr><td colspan="2">Response: The goal is for the responsible entity to build a realistic simulation for the System models which may contain items not listed under Requirement R1, part 1.1.

The SDT disagrees with the VSL comment and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement R1, parts 1.1.1 thru 1.1.6. No change made.</td></tr>
<tr><td>NYISO</td><td>R1 - The NYISO would like to align itself with the comments of the ISO/RTO Council stating that the PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be</td></tr>
</table>

Organization	Comments for Question 1
	consistent with that provided in Mod 10 and 12, there may not be a direct correlation. We, therefore, also suggest the following wording for R1."Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions. "R1.1.2 - Outages of less than 12 months are generally coordinated by operations, not planning departments. In reference to system modeling, it doesn't make sense for outages of less than a year. We therefore recommend replacing "duration of at least six months" with duration of 12 months or more. R1.1.5 - Interchange should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. There are times that economic interchanges between New York and a neighbor may have an impact on one of the transmission systems that may, at times, pose reliability constraints on the operation of the New York system. R1.1.6 - Please define what is included in "resources required to supply load." It is unclear what is included or not included in this requirement. The NPCC definition of "resource" is inclusive.
Response: 1. The SDT believes the existing language is correct and that the suggested changes do not provide additional clarity. No change made. 2. The requirement does not refer to outages occurring within the next 6 months which the SDT agrees would be an operational issue and not a planning issue. The requirement is referring to outages in the planning horizon that have a duration of at least six months. The SDT believes that such outages should be incorporated into the Planning Assessment. No change made. 3. The SDT disagrees and believes that known firm transmission commitments and interchange should be modeled and can affect the transmission system reliability. No change made. 4. "Resources required to supply load" is not a NERC defined term. "Facility" is a defined term and does include generators. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load	
NERC Standards Review Subcommittee	R1 The MRO NSRS interprets that "within their respective areas" refers to the geographic footprint of the TP or PC transmission system. The MRO NSRS proposes clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. M1 The MRO NSRS recommends that words be added to M1 to indicate that each responsible entity must provide evidence that "it is maintaining System models within its respective area, using the latest"?
Response: 1. The SDT believes agrees that the "within their respective area" terminology excludes remote generation and Load buses since they are not within the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT believes that the existing language is adequate and no further change is required.	

Organization	Comments for Question 1
2. The SDT agrees that adding “within its respective area” would help clarify this measure. The SDT has modified M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1	
Central Maine Power Company	R1.1.1 Make this read “Existing Facilities and Resources” so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6 Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and “resources required to supply load” should be replaced with “New planned Resources and changes to existing Resources”We suggest NERC develops a definition for “resource” or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. M1 It is not practical to retain system model information in a hard copy form. This provision should be dropped. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an “or” such that one of them must retain the data and it can be up to them as to who is responsible for data retention.
ISO New England	1. R1.1.1 Make this read “Existing Facilities and Resources” so that it will be a lead in to the changes proposed for 1.1.6. 2. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 3. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and “resources required to supply load” should be replaced with “New planned Resources and changes to existing Resources”We suggest NERC develops a definition for “resource” or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases

Organization	Comments for Question 1
	from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. 4. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. 5. M1It is not practical to retain system model information in a hard copy form. This provision could be dropped. 6. D.1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore the SDT believes that the existing language is adequate and that no changes are required.	
United Illuminating	R1.1.1 Make this read "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. R1.1.2 This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated , beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. 1.1.6.. Resources may not be exclusively sources supplying load. Therefore the reference should not involve load. The focus should be on changes to resources and "resources required to supply load" should be replaced with "New planned Resources and changes to existing Resources"We suggest NERC develops a definition for "resource" or use the following definition found

Organization	Comments for Question 1
	in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions.
Response: 1. The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.	
Ameren	R1.1.2: Inclusion of outages of generation or transmission facilities with a duration of at least 6 months in the models is too restrictive. An outage duration of 1 month would be more appropriate for inclusion in the seasonal peak and off-peak models. R1.1.5: It is not clear from the wording how Firm Transmission Service and Interchange schedules should be considered, or whether the status quo is adequate. A given generating facility may have transmission service commitments which exceed the facility's generating capability. VSL: Given the annual cycle of collecting, revising and submitting system model data under MOD-010 and MOD-012, there could be a lag of several months between receipt of updated data prior to having this data included in the next round of system models. The TP/PC should not be penalized for this.
Response: 1. The SDT believes that the 6 month outage duration required for modeling outages is sufficient. However a utility may exceed this requirement by having lower outage duration if they choose. The outages should be modeled in the appropriate cases whether the outages occur in the spring, summer, fall, winter, etc. 2. The Standard is requiring the modeling of known commitments for Firm Transmission Service and Interchange schedules as a means of stressing the transmission system pre-contingency. If a given generator is reserving transmission capability beyond the capability of the resources to deliver, then someone must have evaluated the system based on a set of assumptions that identified that the system is capable of delivering the service, which would be consistent with this requirement. 3 The System models should be updated in accordance with MOD-010 & MOD-012. No change made.	

Organization	Comments for Question 1
Xcel Energy	R1.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
SERC Planning Standards Subcommittee	R1: MOD-010 and 012 are not directly applicability to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."
SERC Dynamics Review Subcommittee (DRS)	R1: MOD-010 and 012 are not directly applicable to the PC. References to other processes (e.g. tariff requirements or transmission owner agreements) that are utilized to provide this data may be desirable, but do not satisfy R1 as presently written.VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model."

Response: The MOD-010 and MOD-012 standards are not directly applicable to the Planning Coordinator; however the Planning Coordinator has to utilize data provided by others such as that provided in accordance with MOD-010 and -012.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

Manitoba Hydro	Recommend removing "and shall represent projected System Conditions" from R1. This is already clearly contained in R1.1.1

Organization	Comments for Question 1
	through R1.1.6. If the drafting team knows of other projected system conditions then they should be listed in R1.1. "The System Model did not represent projected System Conditions as described in Requirement R1 should be removed from the severe VSL column. By failing to represent 4 or more of the requirements in 1.1.1 through 1.1.6, projected System Conditions are not represented.
Response: The SDT disagrees and believes that there may need to be additional information contained in the models that is not specifically noted under Requirement R1.1. The goal is for the responsible entity to build a realistic simulation for the System models. The SDT disagrees and believes that the second condition under the Severe VSL covers additional items under Requirement R1 itself that are not covered under Requirement parts 1.1.1 thru 1.1.6.	
Northeast Power Coordinating Council--RSC	1. Requirement 1.1.1: Replace "Existing Facilities" with "Existing Facilities and Resources" so that it will be a lead in to the changes proposed for 1.1.6. 2. Requirement 1.1.2 "Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. Known or "known planned" outages will not necessarily fall in the operations timeframe, and as such may not be subject to approval by operations departments. This is especially so given the fact that the earliest start date for Year One is 12 months beyond the current year. 3. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. 4. Requirement 1.1.6 what are "resources required to supply load, gens, HVDC, tie lines? Resources may not be exclusively sources supplying load. The focus should be on changes to resources. "Resources required to supply Load" should be replaced with New planned Resources and changes to existing Resources. NPCC suggests NERC develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.A

Organization	Comments for Question 1
	5. Requirement 1.2 should be added to address the base assumptions for sensitivity and other issues requirements. 6. For Measure M1: Elaborate on "hard copy format". Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.

Response: 1.The SDT believes that the "and Resources" is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1.

2. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. Since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, this situation may be worse than only having two Contingencies as noted in P6. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. No change made.

3. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made.

4. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments.

R1, part 1.1.6 - Resources (supply or demand side) required for Load

5. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.

6. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc.

Organization	Comments for Question 1
Hydro-Québec TransEnergie (HQT)	Requirement 1.1.2 Consideration of known outages should not be included in a planning assessment. Such outages are coordinated by operations and are only permitted if the system can be operated reliably, where assumptions may be different than those used in planning assessments. Including this as a requirement effectively means that the system must be designed to withstand three outages. In those cases where safety, or reliability, or both are a concern by long duration outages (e.g., more than one year), temporary Operating Protocols are implemented to mitigate their impact. If this requirement must be kept, the outages with duration in excess of a year should be considered, rather than those of six months. Requirement 1.1.5 Interchange. Interchange usually refers to non-firm short-term economic transactions that often take place between Balancing Authorities to take advantage of their respective resources surplus (i.e. not needed for local reliability.) However, such transactions should not be modeled in the base case system representation, unless their neutrality to system reliability has been clearly demonstrated. For example, economic interchanges between New England and PJM through New York have an impact on the New York transmission system that may, at times, pose reliability constraints on the operation of the New York system. Requirement 1.1.6 what are "resources required to supply load" " gens, HVDC, tie lines" HQT, as does NPCC, suggests NERC

Organization	Comments for Question 1
	develops a definition for "resource" or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Response: 1. The SDT disagrees and believes that all outages should be modeled to ensure System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages.

The SDT believes that the 6 month duration is appropriate. No change made.

2. The SDT disagrees and believes that known firm Transmission commitments and interchange should be modeled and can affect the Transmission System reliability. No change made.

3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments.

R1, part 1.1.6 - Resources (supply or demand side) required for Load

Organization	Comments for Question 1
Midwest ISO	Requirement R1: The Planning Coordinator may begin model building using provisions from tariff and/or other agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in Mod 10 and 12, there may not be a direct correlation between the two sets of data. This could become burdensome for a Planning Coordinator to make that correlation between the two. Suggest the following wording for R1.Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in the Corrective Action Plan, and shall represent projected System conditions Requirement R1.1.5: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System Models" so it reads as such: "The responsible entity's System model did not"

Response: 1. The SDT does not believe that the proposed language adds any clarity. No change made.

The SDT agrees and will insert this additional wording in the moderate and severe VSLs for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR

		The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

Organization	Comments for Question 1
FRCC Transmission Working Group	Several questions on the details:- R1 requires the maintenance of system models for the purpose of studies and establishes that these models should be updated with the latest data from various sources. Read in context this seems to require that a PA/TP has models, and they are updated either on some sort of regular schedule, for example quarterly or before the start of a study, and use the latest information at the time they are updated. Is this a correct understanding of the requirement? - R1 states that the model should be "..supplemented by other sources as needed, including items represented in the corrective action plan"? Read in context with the overall requirement this allows for projects that are in the corrective action plan to be added to the model as needed, is this the correct understanding? -R1 requires the model to represent "projected system conditions" which include in the list below "Known Commitments for Firm Transmission Service" and "Load Forecast". This seems to require that your known firm transmission service commitments are matched to their corresponding customers load forecast and expected operation profile, relative to load level in the case. Or phrased another way, the model should represent the service and load as they would be expected to operate at the load level in the case. Is this a correct understanding? Comments: With regard to the Moderate Violation Severity Level, what if the entity does not have the "latest" data but the entity did include items in the corrective action plan? Should the "and" between MOD-010 and MOD-012 be an "OR" and have the "AND" be for the High VSL?Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement. 1.1.6 Recommend changing to "Resources expected to supply Load"

Response: 1. The SDT agrees with your understanding. The System models should be updated in accordance with MOD-010 & MOD-012.

2. Yes, this is the correct understanding. Items from the Corrective Action Plan should be included in the models as noted under Requirement R1.

3. The SDT agrees with your understanding.

4. If the entity does not have the latest data, but did include items in the Corrective Action Plan, then the SDT believes the entity would be in violation of a Moderate Severity level. The SDT believes that the existing language is correct. The SDT believes that all System models should represent all known commitments for Firm Transmission Service and Interchange. The SDT does not believe that the proposed language adds any clarity. No change made.

5 The SDT realizes that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT

Organization	Comments for Question 1
has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load	
National Grid	Sub-Requirement 1.1.1: Replace “Existing Facilities” with “Existing Facilities and Resources” so that it will be a lead in to the changes proposed for 1.1.6. Sub-Requirement 1.1.2: This type of event is sufficiently addressed within the existing testing requirements (P6) and therefore should be eliminated, beyond that such outages are reviewed and approved on an operational basis and should not be included in a planning standard. During known outages for equipment upgrades or repairs there may be some increased exposure to load loss, which should be recognized as an acceptable exposure. In the event that this requirement is maintained please change six months to one year. Sub-Requirement 1.1.6: Resources may not be exclusively sources supplying load. Therefore the reference should involve load. The focus should be on changes to resources. “Resources required to supply Load” should be replaced with “New planned Resources and changes to existing Resources”It is suggested that NERC develop a definition for “resource” or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load. ADD 1.2 The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. Measure M1: Elaborate on “hard copy format”. Does that entail maintaining a hard copy of the system model? It is impractical to retain system model information in a hard copy format. This provision should be dropped.
Response: 1 The SDT believes that the “and Resources” is not needed as a lead in to Requirement R1, part 1.1.6 since both Requirement R1, parts 1.1.1 and 1.1.6 are directly under Requirement R1, part 1.1. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2, thus this situation may be worse than only having two Contingencies as noted in P6. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load 4 The SDT believes that the “base case conditions” should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a System model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc.,	

Organization	Comments for Question 1
connected to that bus with associated impedances, ratings, etc.	
Lakeland Electric	Suggesting language “known planned” outages and in place of “known” outages Suggesting language “real & reactive resources” in place of “Resources” “within its respective area”, how about ties?
Response: The SDT does not believe that the proposed language adds any clarity. No change made. The SDT has made clarifying change to Requirement R1, part 1.1.6 based on industry comments since this requirement may not be exclusively sources supplying Load. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load Tie Lines should be modeled as required to achieve conformance with the MOD standards.	
Exelon Transmission Planning	The feedback from Round 3 of comments is appreciated, but there is still a concern that the inclusion of known (or “expected”) transfers is to be studied as a sensitivity. We believe that the base case should already contain the most likely (“expected”) transfer scenario and a sensitivity case would be studied with a less likely transfer scenario. As written it appears that the standard would require that the base case would contain no transfers or some transfer level other than what is “expected”. It is suggested the term “Expected transfers” be changed to “Additional transfers beyond base case conditions”. The use of this term will provide clarity between what is to be modeled in the basecase and what is to be studied as a sensitivity case. There are a number of overlapping requirements with this standard and other standards in various stages of development, such as voltage stability criteria, protection system redundancy, relay loadability, and protection system contingencies that could cause non-compliance with several standards for a single infraction. Suggest removing overlapping requirements be removed from R6, P5 from Table 1, R3.3.3 and R3.3.1, respectively.
Response: 1. Requirement R1, part 1.1.5 requires that known commitments for Firm Transmission Service and Interchange be modeled. However the sensitivity analysis under Requirement R2, parts 2.1.4 and 2.4.3 require that at least one condition not already in the studies be varied by a sufficient amount in order to stress the System by a measurable change in performance. The SDT does not believe that the proposed language adds any clarity. No change made 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: “Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations.” 3. The SDT believes that some overlap is necessary but the SDT has tried to minimize this as much as possible. Requirement R6 deals with defining and documenting certain items such as Cascading, voltage instability, and uncontrolled islanding. Note that Requirement R6 has been clarified to remove “outages” from “Cascading outages”. P5 is a multiple Contingency caused by loss of a single Protection System. R3.3.1 deals with the removal of elements that the Protection System and other	

Organization	Comments for Question 1
automatic controls are expected to disconnect. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3**. Trip Transmission elements when relay loadability limits are exceeded **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Florida Municipal Power Agency, and its Member Cities	The MOD standards for load forecasts (e.g., MOD-016 through 021) do not require submission of a reactive load forecast from the LSEs and RPs; therefore, why is it expected that the TPs and PCs use a reactive forecast that is not provided? From the auditor's perspective, what is expected and acceptable for System models representing reactive load forecasts? Suggested change: 1.1.4 Real Load forecasts and future reactive Load assumptions? Not all system models can represent all "Known commitments for Firm Transmission Service and Interchange". The SDT needs to add "that are expected to be utilized." to the requirement.
Response: 1. Requirement R1, part 1.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. The SDT cannot comment on what an auditor may find compliant or non-compliant. No change made. 2. The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented.	
SRC of ISO/RTO	The PC may begin model building using provisions from tariff or agreements such as its Transmission Owners agreement. While the data may be consistent with that provided in MOD 10 and 12, there may not be a direct correllation. The following wording is suggested for R1.R1. Each Transmission Planner and Planner Coordinator shall maintain System Models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall reflect data consistent with that provided in accordance with the MOD-010 and MOD-012 standards and/or data that is provided in accordance with tariff or transmission owner agreements. The models may be supplemented by other sources as needed including items represented in Corrective Action Plans, and shall represent projected System conditions. AESO does not comment on VSLs or VRFs.
Response: 1. The SDT believes that this is adequate as long as the data remains consistent with that provided in MOD-010 and MOD-012.	
US Bureau of Reclamation	The requirement for the model is not clearly stated. Based on the requirement 2, the models must prove the Corrective Action Plan items developed in 2.7.1. The actions in 2.7.1 are developed by the Transmission Planner or Planning Authority ("List System deficiencies and associated actions needed to achieve required System performance"). Requirement 1 however requires that the model "shall represent projected System conditions". Is the intent of the modelling to demonstrate system performance based on changes proposed by the Tranmission Owners and Generator Owners. Or is it the intent to have the Transmission Planner and Planning Authority develop proposals through system studies that the Transmission Owners and Generator Owners must implement?

Organization	Comments for Question 1
Response: Requirement R1 requires that Corrective Action Plans be included in the models. Requirement R1 includes items represented in the Corrective Action Plans along with represented projected System conditions. The intent of the modeling is to ensure that entities are planning reliable Transmission Systems and have sufficient time to get needed plans in service to continue meeting the TPL-001-1 requirements. The SDT believes that these actions are needed in the planning horizons in order to have a reliable Bulk Electric System. No change made.	
Oncor Electric Delivery	The six month limitation of requirement 1.1.2. “Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.” is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extendible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This non-applicability points out the need for a separate (but equal in scope) operational planning analysis standard.There appears to be a lack of clarity related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability. 1.1.2 ? The requirement will result in the need to evaluate construction sequence in planning studies. 1.1.6 ? What are “resources required to supply load gens, HVDC, tie lines” NPCC suggests NERC develops a definition for “resource” or use the following definition found in NPCC Glossary of Terms, Document A-7: Resource Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.1.1.6 Resources are not serving load but are supporting network operations. ADD 1.1.7 The standard is referring to requirements for sensitivity and other issues without a reference to base cases. It is recommended that each Region have a document that defines what constitutes “base case” conditions. M1What does it mean to have a hardcopy of a system model? 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, are they both required to have identical software to use the data? We recommend that the entities have an option to determine which of the two entities retains the information.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. Please see the NERC TOP standards, as an example, for additional information concerning operational planning. The SDT believes that relay redundancy is best handled in Project 2009-07: Reliability of Protection Systems. However, the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3.** Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
2. The SDT agrees that evaluation of construction sequences would have to be performed in order to successfully model outages as required. 3. The SDT agrees that this requirement may not be exclusively sources supplying Load. As an example, Demand Side-Management (DSM) may be used. The SDT has made a clarifying change to Requirement R1, part 1.1.6 based on industry comments. **R1, part 1.1.6** - Resources (supply or demand side) required for Load 4. The SDT believes that the "base case conditions" should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. 5. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. 6. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility. Therefore, the SDT believes that the existing language is adequate and that no changes are required.	
TIS	The six month limitation of requirement 1.1.2. "Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months." Is is applicable to near-term and long-term Planning studies, but makes the new TPL-001 standard non-extensible to the near-term operational planning studies (next month, next week, or next day). During near-term operational planning periods, it is essential to include the impacts of ALL known outages in the operational analysis.It should be made clear that the TPL-001 Standard is not applicable to the Operational Planning Horizon. This points out the need for a separate (but equal in scope) operational planning analysis standard. There appears to be a double-jeopardy issue related to relay loadability and protection system redundancy. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should only be a placeholder. Similarly, the issues of redundancy are being addressed in more detail in a new proposed standard on protection system reliability.
Response: 1. The SDT agrees that this standard does not apply to the operating planning horizon. See the NERC TOP standards, as an example, for additional information concerning operational planning. 2. As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." 3. The TPL draft is silent on the issue of redundancy. However the SDT has clarified the relay loadability issue in Requirement R3, part 3.3.3 by stating how these are handled in the simulations when these limits are exceeded. **R3.3.3.** Trip Transmission elements when relay loadability limits are exceeded	

Organization	Comments for Question 1
TVA System Planning	TVA agrees with the changes made in R1 - especially the minimum 6 month duration required for outages to be modeled.In R1.1.5, how should partial path transmission service be accounted for in the known commitments for firm transmission service and interchange? VSL: In the Moderate and Severe VSL, insert "responsible entity's" in front of the term "System model" after the "or".

Response: 1. The SDT believes that you should plan for known commitments. Therefore, the part of the partial path that is known should be modeled.

2. The SDT agrees and will insert this additional wording in the moderate and severe VSLs for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1.

American Transmission Company	We propose the following changes and questions: R1 We interpret that "within their respective areas" refers the geographic footprint of the TP or PC transmission system. We propose clarifying that "within their respective area" does not require the inclusion of remote generation or load (metering) buses that are within the declared Balancing Authority area, but may be outside and separate from the TP or PC geographic footprint. R1.1.2 We suggest that this requirement be removed because the "known outage(s)" are only to be included in the models when P1 events are simulated, as specified in R2.1.3. We suggest that the intent of this requirement can be more simply handled by stating in R2.1.3 that "known outages be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur". R1.1.3 Add the qualification of "for the years defined in R2". R1.1.6 We interpret that "Resources required" allows the inclusion of fictional generators in the models when they are needed to

Organization	Comments for Question 1
	make future normal system cases solve. If this is not the intended interpretation, then we suggest modifying the wording to make the desired interpretation more clear. M1 " Revise M1 to indicate that each responsible entity must provide evidence with the added qualification, ". . . it is maintaining System models within its respective area, using the latest . . ."
Response: 1. The SDT believes that the "within their respective area" does refer to the Transmission Planner's or Planning Coordinator's geographic footprint. The SDT does not believe that the proposed language adds any clarity. No change made. 2. The SDT disagrees since multiple outages may be taken during the same time period under Requirement R1, part 1.1.2. The SDT believes that all outages should be modeled to ensure the System reliability during the outage duration. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. See Requirement R2, part 2.1.3 for additional details concerning studies required with known outages. 3. The requirements in TPL-001-1 are all inter-related so no change is required. 4. The SDT believes that this requirement includes any fictional generators that may be needed to match up generation and Load. The SDT has made a clarifying change to Requirement R1, part 1.1.6. **R1, part 1.1.6 -** Resources (supply or demand side) required for Load 5. The SDT agrees that adding "within its respective area" would help clarify this measure. The SDT has modified Measure M1 to include this new language. **M1**. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within its respective area, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
PJM	Consider rewording R1.1 to, -Consistent with the desired year and season a system model shall represent-. This removes some ambiguity about what to include in each model. Possible confusion existed about the multitude of models and what needed to be in each of them. These words deal with each model separately.
Response: The SDT does not believe that the proposed language adds any clarity. No change made.	

2. Requirement R2 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: A number of Commenters requested clarification of on the use of past studies (Part 2.6) either as a supplement to or in place of the annual current year studies (in Parts 2.1 through 2.5). Many also requested that the requirements for Part 2.1 (Near-Term steady state studies) and Part 2.2 (Long-Term steady state studies) be changed from "annual current studies, supplemented by qualified past studies" to "annual current study or qualified past studies".

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizon, respectively. While the SDT envisions that the standard is flexible enough to allow the use of qualified past studies, the planning assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Planning Horizon and one of the years in the Long-Term Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

A number of Commenters questioned the need for two distinct study years to support the planning assessment for the Near Term planning horizon, especially in areas with very low Load growth. They requested reducing the requirements for annual current studies to one study to support the Near-Term planning horizon.

The SDT reviewed the requirements and declines to change to one Near-Term study. Load growth may not be the only determination factor for System performance; other examples are addition or retirement of generation. The SDT therefore, believes that, as a minimum to support reliability, Transmission plans are needed for the time frame just after operation planning (Year One or year two), as well as the time frame at the end of the Near-Term (year five) to allow implementation of solutions, which may require longer lead time.

Many Commenters requested clarification of the Load level(s) to be used in an "off-peak" case. One Commenter explained that the NERC glossary defines Off-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand and On-Peak as those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand. Therefore, the Commenters pointed out that Off-peak can be ANY Load level less than peak, and, as such, can be confusing.

The SDT notes that the intent of Parts 2.1.2 and 2.4.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Commenters also questioned the need for Off-Peak studies because the System Off-Peak is more likely a Stability issue than a steady state issue, and if System Off-Peak becomes a steady state issue, it can be mitigated through generation re-dispatch. Three Commenters also suggest moving Part 2.1.2 to Part 2.1.4 and treating it as one of the sensitivity analyses.

Based on the need to assess System conditions during periods of lower Load, the SDT believes that it would not be appropriate to move the studies of Off-Peak Load conditions from Parts 2.1.2 or Part 2.4.2 to be included in the sensitivity studies required in Parts 2.1.4 or 2.4.3. Sensitivity studies only need to cover one of the six conditions included in the bullets, and this may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed.

Many Commenters suggested clarification that for Part 2.1.3 it must be clear that the reference to outage schedules as listed in Part 1.1.2 (which requires modeling of known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months) must be limited to the planning horizon.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

One Commenter suggested that Part 2.1.3 is not needed if the outages in Part 1.1.2 are properly built into the model. Three Commenters suggested clarifying changes.

Part 2.1.3 codifies studies needed to support the Planning Assessment. The SDT intends for Part 2.1.3 to cover known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. To provide greater clarity, Part 2.1.3 has been revised.

Many Commenters expressed concerns that the use of the words and phrases, “credible”, “sufficient”, “stressed” conditions and “measurable change” may be too vague for compliance. Many Commenters also state that to include and define sensitivity cases and simulations in the standard, the base case assumptions to be used in the assessments must also be defined.

The SDT notes that it envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Likewise, the SDT believes that the “base case conditions”, on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies.

Some Commenters suggested removing the last bulleted item in the list under Part 2.1.4. (Duration or timing of planned Transmission outages).

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent of this bullet item is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6.

Many Commenters also asked whether the (bulleted) list of potential sensitivities in Parts 2.1.4 and 2.4.3 should be the same. Many also expressed concern that Part 2.1.4 (as well as Part 1.1.4) seems to require forecasting reactive Load when most entities forecast demand (MW) and apply a power factor(s) to calculate reactive Load.

The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.

Two Commenters would like clarification that the sensitivity findings do not obligate the Planning Coordinator or Transmission Planner to establish Corrective Action Plans.

The SDT notes that Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary".

Some Commenters suggested clarifying changes to the first sentence in Parts 2.1.4 and Part 2.4.3 from "impact of changes to the basic assumptions used in the model for the list of items below", to "impact of change to the basic assumptions used in the model". For Part 2.4.3, a number of Commenters also suggested a workshop to clarify some of the requirements.

The SDT modified Parts 2.1.4 and 2.4.3. The SDT agrees that a workshop is a good idea. However, because of differences in each Region/Interconnection, the SDT encourages the Regions to hold workshops on issues specific to the Regions utilizing SDT members as participants in the discussions.

Some Commenters expressed concerns that Part 2.1.5 may require entities to have a spare equipment strategy, about the amount of added work, and that it may be redundant with Categories P2, P3, or P6 in Table 1. One Commenter was concerned that this requirement may be difficult for entities such as the Planning Coordinator, who may not own or manage the Transmission equipment or the spare strategy.

The SDT notes that Part 2.1.5 only requires that the Planning Coordinator and the Transmission Planner plan for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment for which there is no spare. In addition, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it into account in selecting the appropriate Contingencies to study and plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others.

Some Commenters state that the requirement is not clear as to whether a Corrective Action Plan is required for those pieces of long lead time equipment without spares. Others believe that the Corrective Action Plans should allow actions such as, “out of merit dispatch”, “operational restrictions”, and “System reconfiguration” if the System cannot meet performance requirements without the facility in service.The SDT notes that Part 2.1.5 is part of Requirement 2, for which a Corrective Action Plan would be required. As stated in Part 2.1.5, the corrective actions should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. The SDT also believes that the concern of allowing actions such as, “out of merit dispatch”, “operational restrictions”, and “System reconfiguration” to be part of the Corrective Action Plan has already been addressed. These actions are allowed in Part 2.7.1 on Corrective Actions.

One commenter seeks clarification on the study requirements for Part 2.1.5 during the time period in which the spare was put in service and no spare would be in place.

The SDT notes that Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5.

A number of Commenters suggested that Part 2.3 be modified to state that it is up to the planner to determine the year of study within the Near-Term Transmission Planning Horizon.

The SDT notes that Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies.

A number of Commenters asked why there is no requirement stipulating short-circuit analysis for the long-term horizon. Another Commenter asked why there is no requirement for short circuit studies similar to Requirement R3 for steady state studies or Requirement R4 for Stability studies.

The SDT notes that Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement a corrective action if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). In addition, the SDT does not believe a requirement to cover short circuit studies similar to Requirement R3 or Requirement R4 is required. The SDT's intent was that while the standard requires short circuit results to be included in the assessment, it does not need to address the technical requirements for completing the short circuit study as that may be entity specific.

Some Commenters questioned the need for short circuit studies to be required in this standard since Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. In addition, the effects of the failure of over-stressed breakers are already included in the events listed in Table 1: for example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).

The SDT states that Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability.

A number of Commenters requested that the SDT clarify Part 2.4.1 as to when "Load models considering induction motors" are required. They requested limits or thresholds to provide Load models based on areas that have Stability limits or issues and based on Loads capable of significantly impacting voltage Stability. This is so that areas that don't have large motors or Stability issues should not be required to add unnecessary Load modeling.

The SDT declines to add specifics on Load modeling requirements because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". All areas including those that do not have large motors can use an appropriate aggregate System Load model.

One Commenter asked if Part 2.4.2 should include requirements for dynamic Load models, considering the behavior of induction motor Loads.

The SDT reviewed Parts 2.4.1 and 2.4.2. In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.

Some Commenters requested clarification as to whether the language in Part 2.5 "proposed generation additions and changes" should also include Transmission additions and changes.

The SDT intends for Part 2.5 to require investigation of Stability issues due to addition of generators, not system stability issues in general. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.

A number of Commenters request clarification on the phrase “material change”, which could impact whether a past study can be used to support a current-year assessment.

The SDT notes that Part 2.6.2 also allows an entity to rely on a past study with a material change if “a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area”. Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

Some Commenters requested clarification of the intent of the Corrective Action Plan and whether projects added in the Corrective Action Plan should be modeled in subsequent years when assessing System performances.

The SDT believes that Part 2.7 requires a Corrective Action Plan to be developed “when the analysis indicates an inability of the System to meet the performance requirements in Table 1”. Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on the criteria Planning Coordinator’s and Transmission Planner’s use for inclusion of such planned projects, and clearly identified as an assumption for the annual assessment as required in Requirement R2 until it is in service or shown to be no longer needed. Two Commenters observed that Part 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0, and TPL-003-0 standards and requested to include in the standard some indication of when activity needs to start to implement the Corrective Action Plan. The SDT notes that the NERC Glossary of Terms defines Corrective Action Plan as “A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that this concern has been addressed.

A majority of Commenters objected to the inclusion of Part 2.9 because it is not reliability related and does not address a performance oriented issue but is rather an information gathering exercise, and suggested that this requirement be deleted.

The SDT agrees with the Commenters as to the nature of the requirement. The SDT also reviewed FERC Order 693 and observed that it directs the ERO to consider including this effort in the standard development process. The SDT has tried through several postings but industry pushback is still significant that this doesn’t belong in a standard. The SDT decided that this effort should best be continued through a NERC data gathering request. The data gathered can then be used in a future revision of this standard.

The following changes were made to the standard requirements due to industry comments:

Requirement R2, part 2.1.3: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Requirement R2, part 2.1.4: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Requirement R2, part 2.3: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Requirement R2, part 2.4: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, part2.6. The following studies are required:

Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Requirement R2, part 2.4.3, bullet #1: Load level, Load forecast, or dynamic Load model assumptions

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

Requirement R2, part 2.5: The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, part 2.6.

Requirement R2, part 2.6.2: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Requirement R2, part 2.7.1, bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.

Requirement R2, part 2.9:

Table 1, footnote 1: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Requirement R2, data retention: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

Organization	Comments for Question 2
Independent Electricity System Operator	(1) Part 2.1.4: We do not believe the sentence: To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is necessary or measurable. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the “how-to conduct” requirement is overly prescriptive and unnecessary, and the condition for “that demonstrate a measurable change in performance” is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes “measurable change in performance”, and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. In our comments on Draft 1, we disagreed with the requirement to conduct sensitivity testing. This is part of the analysis exercise that planners normally perform to help them identify critical parameters/conditions for consideration in planning assessments and in developing remedial plans. Having a reliability requirement to stipulate the details of sensitivity analysis is unnecessary but produces much increased work whose acts are difficult to measure and whose results are not taken any further to arrive at a useful outcome. Once again, we urge the SDT to consider dropping this requirement. (2) Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons

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	and can be supported by. (3) R2.4.1: We believe that “considering the behavior of induction motors” is not necessary since the wording “a Load model which represents the dynamic behavior” already covers this. (4) In part 2.5, we recommend inserting the text “and Transmission Facilities” after “generation” to be consistent with the wording of part 2.3 (5) As drafted, the VLSs do not address missing certain combinations of parts of Requirement R2. For example, the condition assigning a Low, Moderate or High VSL is the failure of one of the parts listed under these columns. There is no assignment for failing more than one of the listed parts. We propose adding a second condition under the High VSL as follows: OR two or more of parts 2.3, 2.6, 2.8 and 2.9.. Also, part 2.5 is missing from the SEVERE VSL. We recommend including it. As written, it is possible to miss say parts 2.1 and 2.5 and still not be captured under the Severe VSL if that is the intent.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner. Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on corrective action plans to “Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary”. No change made. Part 2.3 is for short circuit assessment of the System in general and is more suited for the near-term planning horizon, when Transmission plans are more certain. Lead time to implement corrective actions if found necessary can reasonably be expected to be completed in the near-term time frame. Short circuit studies for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). Therefore the SDT declines to make the change as suggested. For Part 2.4.1, the clause “considering the behavior of induction motor Loads” is a clarification of the intent of this Requirement. Therefore, the SDT declines to make the change. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that time frame is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that time frame, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. The SDT reviewed the VSL assignments and believes that as written they are as intended. In assigning the VSLs the SDT considers the potential lead time to implement the corrective action as well as the impact of non-compliance. Parts 2.1, 2.2, 2.4, and 2.7 cover the basics of planning activities and the lead time to implement the Corrective Action Plan can be longer than the near term planning horizon. As such, failure to comply with two of more of these parts can severely impact future System reliability. Part 2.5 covers long term Stability analysis, corrective actions would likely involve addition of dynamic voltage support, which can reasonably be expected to be implemented within the near term horizon.	
ERCOT ISO	* Requirement R2 (and throughout the standard) What is meant by “its portion of the BES”? Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall prepare?"* Requirement 2.1.3: This is not needed if these outages are properly built into the model.

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	* Requirement 2.1.4: This requirement applies to 2.1.1 and 2.1.2. Why does it omit 2.1.3? Should it be referring to 2.1.3 for P1 contingencies? * How will 2.1.4 be proven? What is the definition of “stress” in this context and what defines “sufficient” stress? What is “measureable change”? What is the expected response to the results of this analysis? For example, if the load forecast must double to “sufficiently” stress the system, is the expectation that facilities should be planned to respond to the stress? * Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. But if this inclusion is only done by a TP, the benefits of coordinating with other TPs may not be realized. * Requirement 2.2: If each entity is responsible to study the System peak Load of its area, but a PC is responsible for multiple TP systems, then what System Peak Load is the PC responsible to study “ a model that includes the non-coincident peaks of all of the TP systems for which it is responsible or the coincident peak demand across the whole system for which the PC is responsible” * Requirements 2.4.1 and 2.4.2: These appear to have inconsistent references to defined terms. Should this be consistent? The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.""On-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.""System: A combination of generation, transmission, and distribution components."* Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." * Requirement 2.7: in each case throughout the standard, replace “planning events” with “planning events as defined in Table 1” and “extreme events” with “extreme events as defined in Table 1” * Requirement 2.7.2: It would be good to clearly state here or in 2.1.4 that results from stressing the system do not always need to be resolved.

Response: BES can cover the entire region or Interconnection. “Its portion of the BES” limits the accountability to only the portion for which the Planning Coordinator or Transmission Planner is responsible. Requirement R7 requires that the Planning Coordinator and Transmission Planner’s coordinate and delineate their individual responsibilities within their portions of BES if there are any overlaps. Therefore the SDT declines to make the change.

Part 2.1.3 codifies studies needed to support the Planning Assessment and as such must be retained.

Parts 2.1.1 and 2.1.2 are “normal” System conditions. Part 2.1.3 covers P1 Contingencies with known long duration outage of a Facility included as Category P0. Therefore, the standard does not require sensitivity studies on top of P1 outage events as specified in Part 2.1.3. However, the standard does not preclude applying Part 2.1.4 to Part 2.1.3.

For Part 2.1.4, The SDT envisions that stressed conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner.

For Part 2.1.5, the Planning Coordinator does not have to own or manage the Transmission equipment or the strategies, it only needs to know the strategy and take it

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into account in selecting the appropriate Contingencies to study. Part 2.1.5 does not require that each entity has a spare equipment strategy; only that it plans for the potential unavailability of long lead time major Transmission equipment. It also does not preclude a Transmission Planner from coordinating its spare equipment strategy with others. For Part 2.2, the intent of the System peak Load case is to model the System conditions at the time of Peak Demand of the System for which an entity is responsible. Therefore, this case should model the coincidental peak of the System. However, the standard does not preclude the Planning Coordinator from also studying System conditions at higher Load levels, such as the non-coincident peak. For Parts 2.4.1 and 2.4.2, the NERC Glossary defines “Peak Demand” as: “1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.” NERC also defines Load as, “An end-use device or customer that receives power from the electric system.” The draft Standard uses “System peak Load” to refer to the System conditions when the Load level is at the Peak Demand of the System being studied; and “Off-Peak Load” to refer to those System conditions when the Load level is lower. For assessing System performance, reasonably adverse System conditions should be modeled. Part 2.6.2 is governed by Part 2.6, which states: “Past studies may be used to support the Planning Assessment if they meet the following requirements”. Therefore the SDT believes that the proposed change does not add clarity and has already been covered. Furthermore, the proposed change would introduce confusion in Part 2.6.1, which is also governed by Part 2.6. Planning event appears once in Requirement R2: Part 2.7 begins with “For planning events shown in Table 1”. The SDT cannot find “extreme events” in requirement R2. Therefore, the SDT was not clear on the issues being raised. Since the language used has the same intent as the proposed change, no change was made. Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to “Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary”. The SDT believes that this concern is covered in the existing draft.	
Bonneville Power Administration	: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies ” It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most

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	entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
Northeast Utilities	[R2.1] The language of this requirement should be revised as follow: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.1.2] Please clarify the load level to be used for "System Off-Peak Load". [R2.1.4] To include and define sensitivity cases and simulations in the standard NERC must also define base cases to be used in the assessments. Refer to comment suggesting the addition of Requirement R1.1.7. [R2.1.5] It is not clear whether a corrective action plan should be developed for this requirement and if we are to develop an action plan should it be temporary and cover only the time period that the major Transmission equipment was unavailable? [R2.2] The language of this requirement should be revised as follow: The long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: [R2.3] Please provide guidance as to what year should be represented when performing short circuit studies or is it up to the Planner to select a year for the study? [R2.5] There is no guidance on the load level that should be used for the long-term stability study as is required by Requirement R2.2.1 for the Steady State assessment. [R2.9] Why the need to report the largest Consequential Load Loss since the TPL Standard does not limit the amount of Consequential Load that could be allowed? We recommend that this requirement should be deleted.

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Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term Transmission Planning Horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study will be performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard is not intended to be prescriptive; therefore, the exact System Off-Peak Load can be specified by the entity performing the study. For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. The Corrective Action Plan is covered in Part 2.7 for planning events shown in Table 1 "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". For Part 2.1.5, the corrective action should, as a minimum, allow reliable operations for categories P0, P1, and P2 during the times when the equipment is expected to be unavailable. For Part 2.2, while the SDT envisions that the standard is flexible enough to allow the use of qualified past studies; the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested in Part 2.2 can result in no current-year study being performed for the Long-Term Transmission Planning Horizon. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. For Part 2.5, the stressed conditions for Stability are often System specific. The intent is to allow the entity performing the Stability study, which is most knowledgeable about its System, to determine the System conditions, including Load levels, on which to perform the assessment. Part 2.9 has been deleted as suggested.	
Central Maine Power Company	2.1.3 In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to

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	shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. 2.7 We suggest changing the word “run” to “condition” such that it reads “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3.” 2.9 The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
ISO New England	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading 2.1 Language should be revised similar to R2.4 as follows: “The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:”2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be

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	more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. "Duration or timing of planned Transmission outages." To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The language in 2.2 should be revised to be similar to 2.4 as follows: "The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
United Illuminating	2.1.3: In the event that R1.1.2 is kept it must be clear that the reference to outage schedules as listed in part 1.1.2 must be limited to the Planning Horizon. Table 1 - There is confusion in interpretation of the table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? 2.1 Language should be revised similar to R2.4 as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:"2.1.2 Should be moved to the list of sensitivities currently in 2.1.4. (Off-peak needs to be more specifically defined). 2.1.4 Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. Duration or timing of planned Transmission outages. To define a sensitivity, NERC must define base assumptions. Refer to Comment on Proposal to add an item 1.22.2 The

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	language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.3 This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. 2.4.2 This should be deleted as it is covered under section 2.4.3. 2.4.3 To define a sensitivity, NERC must define base assumptions. Requirement 2.7 We suggest changing the word "run" to "condition" such that it reads "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. The TPL does not limit the size of the consequential load loss. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent.

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Near-Term steady state analysis as required in part 2.1 is part of the basic planning process, the SDT believes that the steady portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Part 2.1.2 is to support the assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The SDT therefore disagrees that studies of Off-Peak Load should be included in sensitivity studies. Sensitivity studies only need to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions being performed. The exact System Off-Peak Load should be specified by the entity performing the study.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to

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a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1 and not P6. For Part 2.1.4, the SDT believes that the “base case conditions”, on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because Long-Term steady state analysis as required in part 2.2 is part of the basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. . The SDT declines to delete part 2.4.2 as it does not believe that Part 2.4.3 covers System conditions at Off-Peak Load level(s) as envisioned. The Sensitivity study only needs to cover one of the six conditions included in the bullets and may not be the one selected by the entity, resulting in no study of Off-Peak conditions. As in Part 2.1.4, for Part 2.4.3, the SDT believes that the “base case conditions” on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.	
MAPP	2.1.3: It must be clear that the reference to outage schedules as listing in part 1.1.2 must be limited to the Planning Horizon. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? R2.1.4/R2.4.3 The terms “credible” and “measurable change” are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.

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	R 2.1.5 - Spare equipment strategy. This appears to be more of a risk analysis than a simulation study requirement. If a simulation is required then it would appear that the PC/TP would need to rerun the entire system intact study with each "major transmission equipment "that is unavailable as a prior outage (i.e. for each generator, HVDC, SVC, XFMR) over the entire study parameters. How would this be evaluated? Is this not covered under P2 already? We also propose replacing the term "major Transmission" with "BES" because BES is a well defined term while "major Transmission" is not. R2.4.1 We recommend that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. R2.6.2 Change "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not significantly impact the performance results in the study area." 2.6.2 As written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. R 2.7 Corrective Action Plan: Is this not already apart of FERC Order 890? The PC may not be able to develop a CAP as they may not be the owners and would have no say about how a problem will be resolved. R 2.8.1 Suggest using a word other than "deficiencies" as it is associated with non-compliance. R2.9 ? We propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability.

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

For Part 2.1.4, The SDT envisions that credible stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a

Organization	Comments for Question 2
	similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back to service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service. This is not the same as P2. The SDT declines to replace the term “major Transmission equipment” with “BES equipment” because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, “An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems”. For Part 2.4.1, the SDT declines to add specifics, which includes “limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability” because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of “an aggregate System Load model which represents the overall dynamic behavior of the Load”. All areas including those that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. In Part 2.7, the responsibility for developing CAPs lies with both the Planning Coordinator & Transmission Planner regardless of ownership. A FERC Order is not a NERC Standard, and not subject to the NERC audit and enforcement procedures. The SDT declines to change the word “deficiencies” in Part 2.8.1. The SDT believes it is the most appropriate word to capture the SDT intent. Part 2.9 has been deleted as suggested.
Oncor Electric Delivery	2.1.3: It must be clear that the reference to outage schedules listed in part 1.1.2 must be limited to the Planning Horizon. See the TIS comment tor R1. There is lack of clarity in the interpretation of certain rudiments of Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), which voltage class is the allowance for shedding of non-consequential load applied? For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are there allowances to shed load to keep the 345-kV from exceeding its load rating. Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, would there be allowances to shed load to keep the 138-kV from exceeding its load rating 2.1 Language should be revised similar to R2.4 as follows: “The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required: 2.1.2 the term “off peak” is an issue. The definition just says less than peak. 2.1.4 Duration or timing of planned Transmission outages. In order to define a “sensitivity”, NERC must define a base case. 2.1.5 There should be greater clarity to the fact that this is an assessment only, and not a solution. Actions such as “out of merit dispatch”, “operational restrictions”, “System reconfiguration” can be part of a Corrective Action Plan if the system cannot meet

Organization	Comments for Question 2
	performance requirements without the facility in service. 2.2 The language in 2.2 should be revised to be similar to 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current or past studies as indicated inRequirement R2, part 2.6. The following studies are required:2.3 The standard does not indicate a year to study. Is this the discretion of the Transmission Planner? [Review last comment/why doesn't this apply to stability?] 2.4.2 There should be greater clarity to the term "Off peak" Should the Transmission Planner have more discretion in selecting load level. Is there a need for this requirement? 2.4.3 To define a "sensitivity" a base case must be defined for comparison. Requirement 2.7 suggest changing the term "run" to "condition" in "Corrective Action Plan(s) does not need to be developed solely to meet the performance requirements for a single sensitivity run(?) in accordance with Requirements R2, parts 2.1.4 and 2.4.3. 2.7.2 See previous comments on sensitivities. 2.9: The requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, provide greater clarity that there is applicability only to Year One. Furthermore, additional clarification is needed to ensure that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. 2.9 ? Why is it necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss?

Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Part 2.1 covers near-term steady state studies and Part 2.4 covers near-term Stability studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Near-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

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The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. Since such conditions can be case specific, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

The last bullet in Part 2.1.4, “Duration or timing of planned Transmission outages” is intended to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line.

The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 Corrective Action can include, among other things:

- o Installation, modification, or removal of Protection Systems or Special Protection Systems
- o Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- o Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- o Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- o Use of rate applications, DSM, new technologies, or other initiatives.

For Part 2.2, while the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the long-term steady state portion of the studies in Part 2.2 should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire long-term planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies.

The NERC glossary states: "Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand." The intent is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load levels. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The exact System Off-Peak Load should be specified by the entity performing the study.

For part 2.4.3, the SDT believes that the “base case conditions” should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies involving long-term forecasts.

Part 2.7 has been changed to address your concerns.

> **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

For Part 2.7.2, see the responses above to your other comments.

Organization	Comments for Question 2
Part 2.9 has been deleted as suggested.	
FirstEnergy Corp	A. FirstEnergy disagrees with requirement R2 sub-part 2.1.1 requiring the annual completion of two near-term steady-state studies. We believe that on a yearly basis completion of one near-term study and one long-term study is sufficient to interpolate and extrapolate the results needed to cover the entire planning horizon. The team should keep in mind that the overall assessment will include qualified past studies to supplement the results for a more refined view of anticipated conditions. We request that the team revise the near-term annual study requirements to require completion of only one near-term steady-state study and allow the TP/PC flexibility in choosing the appropriate study year. B. In requirement 2.7.1 the team should consider collapsing the 3rd and 4th bullets into a more succinct single bullet that says "Installation or modification of automatic generation runback/tripping". The use of "manual" generation run-back should be accounted for in an Operating Procedure (5th bulleted item). The additional text on the existing 3rd and 4th bullets discussing "single or multiple contingency" is not needed as the text stated in the parent R2.7 text is sufficient. C. We concur with the team's removal of the overly prescriptive requirements to include "initiation dates" and "in-service dates" from the Corrective Action Plans. However, the team may want to ensure some aspect of timing is identified in the Corrective Action Plans. It is recommended that the team revise the text of sub-part 2.7.1 that precedes the bulleted list to read "List system deficiencies, associated actions needed to achieve required System performance and the timing of when the actions are needed"
Response: For Part 2.1.1, the SDT declines to change to one near-term study because as a minimum to support reliability, Transmission plans are needed for the timeframe just after operation planning (Year One or year two), as well as the timeframe at the end of the near-term (year five) to allow implementation of solutions, which may require longer lead time. The SDT reviewed Requirement R2, part 2.7.1 and found that it is clear as written. The SDT therefore declines to make the change. For Requirement R2, part 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, the suggested change to include "timing" is not needed.	
NERC Standards Review Subcommittee	Add R2.7.1 Item #7 The MRO NSRS proposes the addition of the following bullet item to R2.7.1, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." because this explains what is allowed to be considered for Corrective Action Plan developments. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1.] R2.9" The MRO NSRS still proposes that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review. In general, standards should not contain requirements that don't improve reliability. R2.4.1 The MRO NSRS recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability.

<table>
<tr><th>Organization</th><th>Comments for Question 2</th></tr>
<tr><td></td><td>Areas that don’t have large motors or stability issues should not be required to add unnecessary load modeling.</td></tr>
<tr><td colspan="2">Response: Planned system adjustments could include Operating Plans such as re-dispatch. Requirement R2, part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change.

Part 2.9 has been deleted as suggested.

For Part 2.4.1, the SDT declines to add specifics, which includes “limits or thresholds to provide Load models based on areas that have Stability limits or issues and to Loads of substation size and having dynamic characteristic capable of significantly impacting voltage Stability” because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of “an aggregate System Load model which represents the overall dynamic behavior of the Load”. Areas that do not have large motors can use an appropriate aggregate System Load model.</td></tr>
<tr><td>Lakeland Electric</td><td>Agree with the changes made to the spare equipment strategy requirement</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.</td></tr>
<tr><td>Progress Energy Florida, Inc.</td><td>As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF’s previous comments to this effect.</td></tr>
<tr><td colspan="2">Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.</td></tr>
<tr><td>Florida Municipal Power Agency, and its Member Cities</td><td>As worded, 2.1 now seems to require power flow, short circuit and stability studies be done every year for the Near Term. Is this the intent of the SDT? There are smaller systems that do not require this (e.g., if a smaller system has nothing more change form year to year than a 1.5% load growth, and there is plenty of margin on various SOLs, why is another study needed?). FMPA suggests re-wording to: “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies or by qualified past studies as indicated in Requirement R2, part 2.6”

Since 2.2 only has one sub-bullet, 2.2.1 ought to be collapsed into 2.2. We think it would read less confusing as well, see below for suggested phrasing: “The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by a current study of expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected, supplemented with qualified past studies as indicated in Requirement R2, part 2.6.

The short circuit studies of 2.3 should not only assess the fault current interrupting capability of breakers, but also circuit switchers and the momentary current carrying capability of other equipment, such as switches and substation bus. We recommend changing the phrase to: “The analysis shall be used to determine whether the fault current is within the momentary current carrying capabilities and/or fault current interrupting capabilities of (Elements or Facilities) using “.

Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard</td></tr>
</table>

Organization	Comments for Question 2
	could say that only P2 needs to be studied to reduce future confusion. In 2.6, "material change" is ambiguous, especially in regards to load growth. How much load growth is allowed before it is "material"? Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with " For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate "? 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The Planning Coordinator and Transmission Planner should not be responsible in 2.7 for any repercussion of an entity not implementing the Corrective Action Plan. Bullet 2.7 ought to be reworded to developing the Corrective Action Plan only and not implementation. For instance, 2.7.4 requires review of Corrective Action Plans. If a Corrective Action Plan calls for a major transmission addition, then that addition usually is in the domain of the Transmission Owner. If the Transmission Owner decides not to build the transmission upgrade for a variety of reasons (e.g., budgets, etc.), then the Planning Coordinator and Transmission Planner could end up being in violation of the standards through no fault of their own (e.g., even though curtailment of firm service would then be allowed in 2.7.3, if such curtailment would not solve the problem, e.g., if there is not enough pre-contingency re-dispatch available, then the Planning Coordinator would be in violation).Implementation of the Corrective Action Plan, however, is very important. FMPA suggests that another requirement be added to require Transmission Owners, Generation Owners, Transmission Operators, Generation Operators (latter two if there are operating schemes involved) within the planning area of the Planning Coordinators and Transmission Planners to implement the plan as determined by the Planning Coordinators and Transmission Planners, with another requirement requiring that the entities agree on the Corrective Action Plan. This would mean expanding the applicability of the standard. This new requirement ought to have a VRF of High because not implementing the Corrective Action Plan could have high risks. What is the reliability purpose of 2.9? Is it to identify the largest potential supply / demand mismatch? If so, the largest loss of source, usually about 1000 MW, will overwhelm this number. FMPA does not understand the reliability purpose of providing this number, especially since the power flow models already capture most of this information (e.g., amount of load connected to tap substations or radial feeds). This seems to be an administrative item with no reliability purpose, especially since it only applies to P1 (why does it apply to P1 ? how can there be consequential load loss without a contingency, unless it's specific to 2.1.5?) and P2.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the Near-Term and the Long-Term planning horizons, respectively. Short circuit studies (Part 2.3), near-term Stability studies (Part 2.4) and long-term Stability studies (Part 2.5) allow the use of current or qualified past studies. Therefore, as drafted the standard only requires annual steady state studies. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon

Organization	Comments for Question 2
should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. In addition, the two study years are intended to cover both the timeframe just after operation planning (Year One or year two), as well as the timeframe to allow implementation of solutions, which may require a longer lead time. Load growth may not be the only determination factor on System performance; other examples are addition or retirement of generation. The suggested change for Parts 2.2 and 2.2.1 does not provide additional clarity. The SDT declines to make the change. Part 2.3 was changed in the previous posting to include circuit breakers only due to a preponderance of industry comments in draft 3. The SDT declines to make the suggested change. The SDT believe this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation of why the Contingencies selected would produce the more severe conditions. Note that Part 2.3 requires an annual Planning Assessment only. Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth. The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". The SDT believes that the intent is clear. The SDT declines to make the suggested change. Part 2.7 requires that for all planning events in Table 1, the Planning Assessment includes a Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. For 2.7.1, the NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Therefore, your concerns have been addressed. The planners' responsibility is to always have a plan that meets the performance requirements during the planning horizon. If the original CAP can't be implemented, the planner must develop an alternate plan to meet the performance requirements. The definition of CAP includes a timing element as per the Glossary. For issues involving inability to implement a CAP, which is beyond the control of the Planning Coordinator or Transmission Planner, such as the example given, the Planning Coordinator or Transmission Planner can rely on Part 2.7.3 in addition to those actions already allowed tomeet performance requirements. Part 2.9 has been deleted to address your concerns.	
Gainesville Regional Utilities	Combining 4 TPL standards into 1 standard makes for a situation that you will always be audited on all the covered functional areas instead of part of the functions in a given audit. Example, in 2009, TPL-004 was not part of the audit while the other 3 standards were part of the audit. Of course, you should always be current with all functional assessments. I use one assessment document to cover all the functional areas. I do like the added clarity on the time horizons for various studies. I find R2. part 2.1.5 to create a somewhat clearer focus on spare equipment strategy. But the created task could create a lot of

Organization	Comments for Question 2
	work for a utility depending on its configuration and redundancy.
Response: Combining TPL-001 through -006 into one standard was in response to comments from the industry and FERC Order 693. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace, and studies will likely needed to be done to plan for the potential unavailability.	
ITC Holdings	Comments: R2.1.1 Are two distinct study years necessary if a transmission owner can demonstrate that loads within their footprint have minimal growth over the 5 year period, defined to be less than X% of growth? Since the standard requires a relatively large number of studies to meet performance requirements, an initial set of studies along with studies demonstrating that "CAPs work" seems sufficient during periods of load stagnation. R2.1.4, R2.4.3 & R2.7.1. These requirements refer to new facilities which would include new generators. ITC requests clarification as to what constitutes a "new generator" that needs to be considered -- those in the queue, those with signed Interconnection Agreements, those under construction... What is the line of demarcation between what is in and what is out? In addition to the above, ITC also requests clarification as to whether or not these requirements apply to new generators, who connect to the network as "Energy Only" resources and, are either, not required to construct facilities needed to meet reliability requirements or are allowed to operate as "Energy Only" until needed facilities are constructed. The CAP for these facilities is that they will be curtailed or other generation will be curtailed should "operating" violations occur. Under market mechanisms, these generators are allowed to operate if their energy prices are lower than other generators whose curtailment eliminates the violation, even though the curtailed generators have paid for the facilities needed to meet reliability requirements. As the standard is written, these requirements imply that all generators must be included in studies. Were we to do so, significant standards violations might result. Does the Transmission Owner have to study all violation scenarios or include all "Energy Only" generators in studies when the CAP is always the same: "Market redispatch". Please clarify study scenario requirements for "Energy Only" resources.
Response: For Part 2.1.1, Load growth may not be the only determination factor on system performance; other examples are addition or retirement of generation. The two study years are intended to cover both the time frame just after operation planning (Year One or year two), as well as the time frame to allow implementation of solutions, which may require longer lead time. NERC Standards specify what the requirements are and not how to meet the requirements. The SDT therefore declines to specify how the studies are to be done. The intent of the standard is to allow the Planning Coordinator or the Transmission Planner performing the studies the discretion on the sensitivities (Parts 2.1.4 and 2.4.3) to investigate and the generators to be assumed in the Corrective Action Plan (Part 2.7.1). The SDT believes that the requirements under this draft do include "Energy Only" generators. Please note under Requirement R2, part 2.7.1 that manual and automatic generation runback/tripping is allowed as a response to single or multiple Contingencies to mitigate Steady State performance violations. Also automatic generation tripping is allowed for single and multiple Contingency events to mitigate Stability performance violations	

Organization	Comments for Question 2
Deseret Power	Comments: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Part 1.1.4 and Part 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast	
SCE&G	Does R.2.9 refer to customer load only or does it include pumped storage facility pumping loads?
Response: Part 2.9 has been deleted based on industry input.	
Orlando Utilities Commission	I like the clarification of "summarize results" compared to the wording in the prior edition. -It is obvious an attempt has been made to further define when past studies may be used, but I think it is still a bit confusing. Requirement 2.1, 2.2 appear to be saying that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the

Organization	Comments for Question 2
	requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following: For 2.1 and 2.2 revise the statement to read "…and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the required annual current studies listed below. The reference to R2.6 is removed since including it invites confusion over when prior art can be used and if the material is solely supplemental, then there is no reliability advantage to limiting what can be incorporated a supplemental material. R2.6 should also be revised to read "Past studies may be used in lieu of current studies for R2.3, R2.4, R2.6 if they meet the following requirements:" This will insure that it is very obvious in both places when prior art may be used in lieu of new work. -R2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, like inserting or removing text, not changes in the underlying transmission system which is what I think you are really targeting. -R2.1.4 and 2.4.3: The statement "sufficient amount to stress the system…credible conditions…demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range and combination of items that could be used) 1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not. 2. That the increase should be substantial, for example growing the load at 2x the expected growth rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the sensitivity is inadmissible. Is this a correct understanding? -R2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? The next comment is very closely related to this one. -R2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required?

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies should be done annually covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. The remaining requirements for Short circuit studies Part 2.3), near-term stability studies (Part 2.4) and long-term Stability studies (Part 2.5) can then be covered by current or past studies.

The SDT declines to change Part 2.6 to read "Past studies may be used in lieu of current studies for Requirement R2, parts 2.3, 2.4, and 2.6 if they meet the following requirements" because it does not add clarity.

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Part 2.6.2 has been revised to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance". Part 2.7 requires a Corrective Action Plan to be developed "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions based on that the criteria Planning Coordinator and Transmission Planner use for inclusion of such planned projects, and clearly identified as an assumption for the annual Assessment as required in Requirement R2, until it is in service or shown to be no longer needed.	
TVA System Planning	In R2.1.4 and R2.4.3, TVA is concerned about the use of the words "sufficient" and "measurable" from a compliance standpoint. TVA believes that these words should be deleted or at least better defined to clarify the actual intent from the SDT on what is technically required for these sensitivity studies. TVA agrees with limiting R2.1.5 spare equipment strategy to just the P0, P1, and P2 single contingency categories. In R2.7.3, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted if situations arise that are beyond the control of the TP or PC. However these actions are not useful for stability related issues. TVA suggests that for stability related issues, if situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the TP or PC is permitted to allow some generation to lose synchronism utilizing out of step relaying or other protection method to correct the situation that would normally not be permitted in Table 1. We appreciate the deletion of the previous requirement on non-Consequential Load Loss from the previous draft of TPL-001-1.R2.9: Recommend that this refers to customer loads only, and not to include utility loads such as pump-storage or compressed air generating plant pumping load.
Response: For Part 2.1.4, The SDT envisions that stressed conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner. For Part 2.7.3, most of the situations that are beyond the control of the Transmission Planner or Planning Coordinator usually involve permitting or long lead time projects. If there is a Stability issue, there should be time to implement a CAP. No change made. Part 2.9 has been deleted in response to industry comments.	
Lafayette Utilities System	LUS is satisfied that the current version resolves the issues we raised as to R2.

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends a minor editorial to 2.1.4. The subrequirement states that "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies, by a sufficient amount to" The subrequirement as written is not clear whether the condition to be varied is to be one not included in the base studies or a condition that is not varied as part of the sensitivity studies. MidAmerican recommends that this subrequirement be changed as follows: "To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions FOR WHICH VARIATION IS not already included in the studies, by a sufficient amount to"? The words in caps are words that MidAmerican suggests are added to this part of requirement 2. MidAmerican recommends that the SDT clarify section 2.4.1 and when load models considering induction motors are required. The clarification should add limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting system damping. Areas that don't have large motors or stability issues should not be required to add unnecessary load modeling. MidAmerican recommends that the SDT modify 2.6.2 by changing "to demonstrate that System changes do no impact the performance results in the study area" to "to demonstrate that System changes do not SIGNIFICANTLY impact the performance results in the study area." The word that is in all caps is added. 2.6.2 as written results in an unrealistic requirement to review every impact minor or large and determine which meets this item and which do not. The recommended change solves this problem. MidAmerican recommends the data retention for R2 and M2 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "THE Planning Assessments performed since". The word in all caps is a word suggested to be added.
Response: The SDT declines to make the change because it does not add clarity to the requirement. For Part 2.4.1, the SDT declines to add specifics, which includes "limits or thresholds to provide load models based on areas that have stability limits or issues and to loads of substation size and having dynamic characteristic capable of significantly impacting voltage stability" because such specificity needs to be determined by the entity performing the study. Part 2.4.1 allows the use of "an aggregate System Load model which represents the overall dynamic behavior of the Load". Areas that do not have large motors can use an appropriate aggregate System Load model. The SDT declines to make the change suggested in Part 2.6.2 because it did not add more clarity than the existing language. The SDT has made the suggested change. **Requirement R2, data retention**: The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.	
British Columbia Transmission Corp	none

Organization	Comments for Question 2
Response: The SDT thanks you for your comments.	
SERC Dynamics Review Subcommittee (DRS)	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1.Bullet 1 of R.2.4.3: change "Dynamic Model" to "Dynamic Load Model". Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.We recommend that the expected largest consequential load be limited to customer load, not utility load, i.e., pump-storage.
Response: For Part 2.1.4, The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. Bullet 1 of Requirement R2, part 2.4.3: has been revised to address your concerns. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions Part 2.9 has been deleted in response to industry comments.	
SERC Planning Standards Subcommittee	Part 2.1.4 and 2.4.3: delete the word "sufficient." We appreciate the deletion of the previous R2.9 on non-Consequential Load Loss from the previous draft of TPL-001-1. Part 2.9: Does this refer to customer loads only, or does it include pump-storage or compressed air generating plant pumping load.
Response: The word "sufficient" is needed in Part 2.1.4 and Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. Part 2.9 has been deleted in response to industry comments.	
CenterPoint Energy	Part 2.2: CenterPoint Energy recommends deleting part 2.2 since studies performed in the Long-Term Transmission Planning Horizon have dubious value for organizations whose longest lead time items take less than five years to construct. Even for organizations requiring longer than five years to build some projects, it should be noted that beyond the five year horizon, generation reserve margins have generally been exhausted, requiring speculation as to the location and size of future generating resources in developing system models. In recognition of this reality, the current set of TPL standards appropriately require that assessments be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may require longer lead time solutions. Part 2.5: Part 2.5 appears to have been added in response to one comment to the 3rd draft. In fact, the commenter did not recommend or propose the requirement found in 2.5, but only asked about the SDT's intent regarding this matter. CenterPoint

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	Energy strongly disagrees that part 2.5 is necessary or advisable and recommends that it be deleted. We wholeheartedly agree that Transmission Planners should consider and selectively study potential stability concerns. However, we believe that Transmission Planners are already considering and selectively studying potential stability concerns, and deleting part 2.5 would not preclude the continuation of these practices. However, we oppose mandating stability analysis in the Long-Term Transmission Planning horizon of proposed generation additions or changes due to the uncertainty of where and how much generation will actually be constructed beyond the five year horizon, particularly since generation can be built much faster than five years and can easily invalidate any such assessment. Part 2.7: CenterPoint Energy recommends that part 2.7 be revised to add a reference to part 3.4 and part 4.4 as follows: For planning events shown in Table 1, selected in accordance with parts 3.4 and 4.4, when the analysis. This recommended change is to prevent possible ambiguity or conflicts between part 2.7 and parts 3.4 and 4.4. Part 2.9: CenterPoint Energy agrees with multiple commenters to the 3rd draft that part 2.9 (previously 2.8) should be deleted. Part 2.9 is an unnecessary reporting requirement that has no actual bearing on reliability. By continuing to insist on R2.9, the SDT seems to have inappropriately ignored industry comments to the previous draft while ironically inserting R2.5 into this draft in response to only one industry comment (which did not actually advocate that R2.5 was necessary). CenterPoint Energy urges the SDT to reconsider its dismissal of industry concerns regarding R2.9.
Response: For Part 2.2, the SDT believes there is value in taking a long range view in planning to assess the general trend. The effort can be useful even taking into consideration the uncertainty surrounding long-term planning studies. Since the Long-Term Transmission Planning Horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 or 7 in the Long-Term Transmission Planning Horizon and then use this study as the past study to supplement the near-term studies in the following year(s). For Part 2.5, The SDT believes it is important to evaluate Stability when the planners are evaluating new generation addition or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. Part 2.7 is the Corrective Action Plan resulting from the Planning Assessment. Part 3.4 covers the requirements for studies supporting the steady state portion of the assessment; and Part 4.4 covers the requirements for studies supporting the Stability portion. The SDT believes that Part 2.7 is clear as is and no change is needed. Part 2.9 has been deleted in response to industry comments.	
Progress Energy Carolinas	PEC believes that the language of R2.5 "proposed generation additions and changes" should be clarified as to whether transmission changes near generators are included or not. PEC believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that	

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the generator's Stability impact be evaluated. Part 2.9 has been deleted in response to industry comments.	
Portland General Electric Co.	PGE believes that the scope of the studies mandated by this requirement should be limited to elements energized at 200kV and above, elements included in generator interconnection, and elements included in interconnections with other utilities. PGE's 115kV system functions to provide "load service" rather than transmission and does not impact the grid in the same manner as the 230kV and 500kV elements that comprise PGE's transmission system. PGE further believes that the requirement to conduct off-peak studies should focus on the varied generation patterns and impact to recognized transmission paths (for WECC, those identified in the WECC Path Catalog) rather than including the full range of studies that are required for on-peak studies. PGE's transmission system is embedded within the larger regional transmission system of the Bonneville Power Administration, and studies of System Off-Peak Load will not reveal any meaningful data internal to PGE's system. Finally, PGE believes that the wording of R2.6.2 is so restrictive that the entire intent of the subrequirement would be negated. PGE believes that "material changes" is such a broad term that every past study would have to have such changes made to reflect the system as it currently exists. Therefore, a company seeking to use a past study to support its Planning Assessment would have to provide a "technical rationale" showing that the material changes do not impact performance results. An effort to demonstrate a technical rationale in a manner that would satisfy future auditors would in many cases be more burdensome than performing a new study.
Response: NERC Reliability Standards apply to BES elements as defined by each Regional Entity. No change made. The SDT believes that System Off-Peak Load studies are a valuable tool in proper planning. Therefore, your Planning Assessment needs to address the results for your System of an Off-Peak Load study regardless of whether you conduct the studies or you rely on studies done by others. No change made. The SDT does not agree that developing a 'technical rationale' is such an onerous task. One can utilize their professional judgment, point to past studies of similar conditions, etc. The key is to thoroughly explain your decisions. No change made.	
FRCC Transmission Working Group	Please further clarify the definition when past studies may be used. Requirement 2, bullets 2.1, 2.2 appear to say that current studies must be used, but that additional information can be provided if desired and it meets certain requirements. Sub-Requirements 2.3, 2.4 and 2.5 seem to allow use of past studies that meet the requirements of 2.6 in lieu of new work. If this is the correct understanding then I suggest the following:For 2.1 and 2.2 revise the statement to read "and be supported by the following annual current studies. The analysis may also include other current and past studies in addition to the annual current studies listed below. R2Bullet 2.6 should also be revised to read "Past studies may be used in lieu of current studies for Bullets 2.3, 2.4, 2.6 if they meet the following requirements: This will insure that it is very obvious the planner, when they may or may not use prior art in place of new work and it's specified in all places in the standard where this is referenced.For these supplemental or "above and beyond" studies, 2.6 should not be referenced. First of all it makes it confusing, since 2.6 is primarily concerned with prior art being used in lieu of new work. Also if the material is supplemental, then it's supplemental and setting requirements on it will

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	only reduce the material provided not improve the reliability of the system. -2.6.2 Consider revising "the study shall not include any material changes" to "the system represented in the study shall not include any material changes". Stating that "the study shall not include material changes" implies changes to the study from the time it was performed to the time it was used, not changes in the underlying transmission system which is what I think you are really targeting. -2.1.4 and 2.4.3: The statement "sufficient amount to stress the system"credible conditions"demonstrate a measurable change" implies that a sensitivity must meet three general criteria: (I will be using load forecast as an easy example, but obviously there is a range of items that could be used)1. That it is expected to increase stress, for example increasing the load forecast would general increase stress, where decreasing it would not.2. That increases should be substantial, for example growing the load at 2x the expected rate vs 1.01x the expected rate. 3. That the change doesn't have to exceed the bounds of credibility. If a 2x or 3x increase doesn't result in a stack of new constraints, it does not mean the increase has to go to 10x the forecast just to show extensive effects. Is this a correct understanding? , realizing that I'm only referencing load growth for simplicity, it not being the only sensitivity? -2.1.4 and 2.4.3: The first sentence "impact of changes to the basic assumptions used in the model for the list of items below", please consider changing to just "impact of change to the basic assumptions used in the model". Including the "list of items below" implies that all items must be addressed, which seems to conflict with the second sentence which specifically allows one or more. -2.7: Is the "Corrective Action Plan" intended to document all of an entities planned future reliability related transmission projects and operational procedures? Or is it intended to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements? -2.7: If a project is added one year to the "Corrective Action Plan" but then in the subsequent year has been added to the model, resulting in simulation showing no performance violations, should it be removed from the Corrective Action Plan? Or should it be referenced in the plan each year until it is either in service or demonstrated to no longer be required? Comments: With regard to the Lower VSL, is 2.6 considered to be met if only one of two sub-requirements (2.6.1 or 2.6.2) is met? With regard to the Moderate VSL, is 2.8 considered to be met if only one of two sub-requirements (2.8.1 or 2.8.2) is met? Also, since 2.3 depends on 2.6, what happens if an entity does not meet R2.6 because it did not meet one of the sub-requirements of 2.6? With regard to the High and Severe VSL, if any one of the sub-requirements of 2.1, 2.2, 2.4 or 2.7 is not met, is the entire sub-requirement considered not met? (This question is generic throughout all VSL) Also, for the short circuit study of 2.3 (and 2.8), it is not necessary to study all of the contingencies, just P2. Taking other Facilities out in addition to the fault will only reduce fault current. Auditors may not be aware of that and maybe the standard could say that only P2 needs to be studied to reduce future confusion. Is the intent of the SDT to have 2.7 apply to all previous bullets in R2? If so, then it could be made clearer by starting 2.7 with

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	"For the analyses discussed in 2.1 through 2.5, and for the planning events shown in Table 1, when the analyses indicate " 2.7 seems to have lost the reference to lead times for Corrective Action Plan(s) that were present in the existing TPL-001-0, TPL-002-0 and TPL-003-0 standards, is that the intent of the SDT? Since only two of the years in the near term need to be studied, and one of the year's in the long term study, there ought to be some method to determine when a Corrective Action Plan is needed, the lead time of that Corrective Action Plan, to give an indication of when activity needs to start to implement the Corrective Action Plan. The requirement clearly states that "For the steady state portion of the Planning Assessment " it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. Please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one sub-requirement.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

The SDT declines to make the suggested changes in Parts 2.1, 2.2, and 2.6 because they do not add clarity.

The SDT has revised Part 2.6.2 as suggested.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

For Parts 2.1.4 and 2.4.3, the example you gave is a valid example for addressing "the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance".

Part 2.1.4 and 2.4.3 have been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

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Requirement R2, part 2.4.3: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Part 2.7 requires a Corrective Action Plan to be developed for "when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, the intent is to address situations where simulation and the application of currently planned projects and procedures are insufficient to meet the performance requirements. If a project is added to the Corrective Action Plan, it should be included as part of the study assumptions (and clearly identified as such), based on the criteria that the Planning Coordinator and Transmission Planner use for inclusion of such planned projects, for the annual Assessment as required in requirement R2, until it is in service or shown to be no longer needed.

For the VSL for Requirement 2, both Parts 2.6.1 and 2.6.2 as well as Parts 2.8.1 and 2.8.2 must be met for the requirements to be met.

If an entity relied on a past study, which was not a qualified study in accordance with Part 2.6, then based on the standard, it would not meet the requirement in Part 2.3.

The intent is that with regard to the High and Severe VSL, if any one of the sub-requirements of Parts 2.1, 2.2, 2.4, or 2.7 is not met, the entire sub-requirement will be considered not met.

The SDT believes this concern on Part 2.3 is covered. The Transmission Planner or Planning Coordinator can provide an explanation for why the Contingencies selected would produce the more severe conditions. Part 2.3 requires annual Planning Assessment only.

The intent of Part 2.7 is to be applied to all "planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1". Therefore, a reference to Parts 2.1 through 2.5 is not needed.

For 2.7.1, NERC Glossary of Terms defines Corrective Action Plan as "A list of actions and an associated timetable for implementation to remedy a specific problem. Also, Part 2.7.4 requires that the CAP be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. By including the timing of needed action and requiring such reviews in subsequent Assessments, any deficiencies, if not adequately addressed, will become violations. Therefore, the SDT believes that your concerns have been addressed.

Part 3.3.2: Generator protections exist that can result in generator tripping for bus voltage below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Part 3.3.2 would require the planner to trip the generator in the post-Contingency case to assess if performance is met with the generator tripped. No change made.

Part 3.2 & Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events:

Requirement R3, part 3.3: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

Part 3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made.

Part 3.1/Part 3.4 & Part 3.2/Part 3.5: The SDT does not believe that combining the requirements would provide any significant advantage. No change made.

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American Electric Power	R 2.6.2, as written, may lead to misinterpretation. Following are two alternative suggestions to remedy this issue for the SDT's consideration: 1) "For steady-state, short-circuit, or Stability analysis: the study shall be rendered obsolete by any material changes unless?" or 2) "For steady-state, short-circuit, or Stability analysis: the system shall not include any material changes unless?" While R3 (steady-state studies) covers 2.1 and 2.2 (steady-state assessments), and R4 (stability studies) covers 2.4 and 2.5 (stability assessments), there does not appear to be a corresponding requirement (short circuit studies) to cover 2.3 (short circuit assessments). We recommend that a new requirement be established and numbered to align between existing requirements R3 and R4.
Response: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.3, the SDT does not believe a requirement to cover short circuit studies similar to Requirement 3 or Requirement 4 is required. The SDT's intent is for the short circuit study results to be included in the assessment. It does not believe that the standard needs to address the technical requirements for completing the short circuit study as that may be entity specific. Therefore the SDT declines to make the change as suggested.	
NYISO	R2. - The NYISO tariff establishes a biennial "Comprehensive System Planning Process," Compliance with an "Annual Planning Assessment" will therefore be a simple repetition of data reported in the prior year assessment. Please clarify that this is acceptable. We believe that the use of "past studies" provides for this. R2.1 - "Steady state" should be defined upfront with other definitions. In defining "steady state" is "thermal voltage" the primary metric being measured? R2.1.1 - Again want to confirm that due to the NYISO biennial planning cycle, that use of "past studies" will be acceptable. R2.1.2 - Please define what is intended by "off peak." Our reading is that it is ANY load level less than peak. Also, consistent with our comments on the prior draft, system off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis. R2.1.4 - This is just too vague to be a useful requirement. The sentence ? To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. is too subjective to be enforceable. Either definitions of phrases like "sufficient amount" "credible conditions" and "measurable change" are included, or the requirement needs to be written more clearly to state what is actually being required without such high level of subjectivity. Further, we believe that this sentence may not be necessary at all, as the first sentence in 2.1.4 provides sufficient detail to conduct sensitivity analysis without being overly prescriptive. R2.4.3 As much of this language is a repeat of language in 2.1.4, above, our comments there also apply to this section. R2.6 - "Past Studies may be used to support the Planning Assessment if they meet the following requirements" and the sub-

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	requirement R2.6.2 states that for SS, SC, or stability analysis the study shall not include any material changes, such unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While this is better than the prior draft, the NYISO still would like more clarity on the definition of "material changes." Would the inclusion of a technical rationale satisfy ANY change, regardless of magnitude, in a past study. Or could we just invoke the usage of a statement such as "The NYISO feels this change does not constitute a "material change." to be compliant with this requirement? We recommend that the regional entity should have a process to determine whether changes are material that is similar to the NPCC's process for determining what level of annual transmission review should be conducted each year. Finally, does this only relate to, or is limited to, the LATEST PLANNING HORIZON system model R2.7 Recommend that in the sentence "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity" wording should be changed to "performance requirements for any single sensitivity" R2.7.1 Recommend changing phrase that leads into list to read "Such actions including, but not limited to:" R2.7.2 - Recommend consideration of striking this section. It is not clear how an entity can provide a rational for unnecessary actions. Further, if actions are not necessary, what limit would there be on a rational, so they would seemingly be useless? Finally, it is stated above, corrective action plans should not be required for sensitivity studies. R2.9 There does not seem to relate to any reliability need the NYISO is aware of for this requirement to remain.

Response: Regarding Requirement R2 and Part 2.1.1, the SDT believes that NYISO's current process is inconsistent with Parts 2.1 (covering near-term steady state studies) and 2.2 (covering long-term steady state studies) of the draft Standard. Both Parts 2.1 and 2.2 require an annual current year study. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon.

For part 2.1, the SDT does not believe a definition for steady state is needed as this is a well understood term. There is no 'primary' metric – see the Table 1 Header Notes for more details.

The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would be appropriate to investigate Off-Peak steady state conditions to ensure that System performance can meet requirements under all demand levels. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load and System conditions should be specified by the entity performing the study.

For Parts 2.1.4 and 2.4.3, The SDT envisions that credible "sufficient" "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different and the standard should not be overly prescriptive.

Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". The intent is to assess system performance based on the latest available information. Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth, generation or Transmission additions or modifications.

Part 2.7 has been changed to address your concerns.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements

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in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.7.1 is simply a list and an entity can always do more than what is required in the Standard. No change made. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this would be the rationale to state that a Corrective Action Plan would not be necessary. Part 2.9 has been deleted in response to industry comments.	
Xcel Energy	R2.1 The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies” R2.1.5 Does “The Planning Assessment shall reflect” mean that the entity must meet the performance requirements for categories P0,P1,and P2 during the equipment unavailability? R2.9 As commented in the previous draft, we do not believe this requirement contributes anything to improving BES reliability. Therefore, we strongly recommend deleting this requirement.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. For 2.1.5, your interpretation is correct. Part 2.1.5 requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. If the spare equipment strategy can result in unavailability of long lead time equipment, the study will need to also be modeled with the piece of equipment out of service as P0. Part 2.9 has been deleted as suggested.	
Ameren	R2.1.3: The wording for this requirement needs clarification. It is suggested that the following language be submitted as a replacement: Known outages of generation or Transmission facilities should be included in the models representing those

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	System peak or Off-peak conditions when outages are scheduled. R2.1.4 and R2.4.3: The phrase “by a sufficient amount” should be modified to “by an amount”. Also, in R2.4.3, “dynamic model assumptions” should be changed to “dynamic load model assumptions.” R2.6.2: Recognition should be made of the fact that cancellation of generation or transmission projects, which may have been included in a previous study, would decrease fault levels, and would reduce or eliminate the need for short circuit analysis. R2.8: Would the Planning Coordinator be required to review, replicate, or validate short circuit studies? We appreciate the deletion of R2.9 from the previous draft of TPL-001-1 and eliminated the reporting of Non-Consequential Load Loss for each of the planning events. In R2.9, it is recommended that the largest Consequential Load Loss not include items such as pumped storage load or other utility load.
Response: Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. For Parts 2.1.4 and 2.4.3, the SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.4.3 has been revised as suggested. **Requirement R2, part 2.4.3, bullet #1:** Load level, Load forecast, or dynamic Load model assumptions For Part 2.6.2, the SDT agrees with the expectation concerning short circuit studies. For Part 2.8, as in other parts of this draft standard, the Planning Coordinator is responsible for its portion of the BES. It may delegate the work by agreement, it is, however, still responsible. Part 2.9 has been deleted in response to industry comments.	
Manitoba Hydro	R2.1.4.: The first sentence implies that all sensitivities should be studied. The second sentence refers to one or more. I suggest the following change to the first sentence: "....basic assumptions used in the model." (i.e. delete "for the list of items shown below." from the end of the first sentence.) R2.4.3: The exact same change as above in R2.1.4. R2.1.5: We assume the intent of the standard would be to perform an annual review of the inventory of spare equipment to determine if the spare strategy required updating. For example, if a transformer failed and the spare was moved into position, a new spare would be ordered to replace the failed one. During the period, when no spare was in place, additional assessments would be required to ensure meeting Table 1. Can the drafting team clarify? R2.5: The drafting team modified “material changes” to simply “changes” in R2.5. This does not add clarity. Given that R2.5 is

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	related to Stability Analysis, perhaps "changes" could be modified to "changes that could impact stability or voltage". R2.6: Recommend changing "the study" to "the past study" and "an older study" to "an older past study" to ensure no confusion could result from past and current studies. Can the drafting team explain how a past study can have material changes in R2.6.2? Perhaps R2.6.2 could be deleted. VSL: We would recommend moving R2.8's VSL from Moderate to both High and Severe. R2.8 requires a corrective plan to be developed when the short circuit duty of a circuit breaker is known to be exceeded. This is safety issue and a reliability issue.

Response: In Parts 2.1.4 and 2.4.3, the first sentence has been revised as suggested.

> **Requirement R2, part 2.1.4**: For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

Part 2.1.5 does not address the specific requirements of an individual plan. Since a Planning Assessment is required annually, the analysis required under Part 2.1.5 is an annual requirement. The answer to the specific example would depend on a variety of factors, including the timing of the failure, the length of time that it would take to replace the spare, your Operation Planning time horizon and the specifics of your individual spare equipment strategy. The language in Part 2.1.5 states "the impact of this possible unavailability on System performance shall be assessed", which must be completed annually as a part of your Planning Assessment. The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing (Year One) is defined as the planning window that begins 12-18 months from the end of the current calendar year. After the original spare is put to use, if a new spare can be made available before Year One in the next Planning Assessment, the time period during which no spare is available could then be covered in Operation Planning studies. Longer delivery times would impact the spare availability and an appropriate assessment would be expected in Year One by the Transmission Planner. In addition, to provide greater clarity, the SDT has revised the first sentence of Part 2.1.5 to read, "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed.

> **Requirement R2, part 2.1.5**: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5, the SDT declines to make the change as suggested because the suggested change does not add clarity.

The SDT declines to make the change suggested in Part 2.6 because it did not add more clarity than the existing language.

The SDT has revised Part 2.6.2 to provide additional clarity.

> **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes

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unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. While the SDT agrees that the short circuit analysis is important, Part 2.8 has been assigned a VSL based on its need to fulfill Requirement R2. Safety is covered in other venues.	
Tri-State Generation and Transmission Association	R2.2 What is an "annual current study"? Would this include previously performed studies that are still applicable?? R2.2. What is "qualified past studies"? We have no definitions for "qualifying" previous work. This might be remedied by inserting the term "qualified" in R2.6.? R2.1.4. Sensitivity cases could add much work to the existing process. However, the standard calls for "at least one" of the listed sensitivity studies to be performed. R2.2.1. The requirement to perform a "current study" assessing expected System peak Load conditions, for one of the years in the Long-Term Transmission Planning Horizon, is extra work if a valid/qualified study is available. If the intention here is to have a valid study for at least one of the years 6 to 10, then perhaps some simple rewording will solve the problem. We ascribe to the concept of requiring annual assessments, but not necessarily requiring repeated analysis if system changes do not warrant restudy. Hyphenate "in-service" R2.6.1 Change "the study shall be five calendar years old or less" to: "the study is five calendar years old or less" R2.6.2 change the phrase "shall not include any material changes" to "does not include any material changes" R2.6.2 it is not clear what is meant by "material changes" - different "Study conditions" or "changes that could cause different results for a particular study"?
Response: In Parts 2.2 & 2.2.1, an "annual current study" is one that must be done in the current assessment cycle. Previously performed studies can be used to supplement the current study, but not in place of it. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. In Part 2.2, the "qualified past studies" are as indicated in Requirement R2, part 2.6. The SDT believes that the existing language is clear and changes are not needed. Part 2.1.4 – There is no question here so the SDT is unable to provide a specific response. For Part 2.6.1, the SDT declines to make the changes as suggested because they do not provide more clarity than the existing language. The SDT has revised Part 2.6.2 to address your concerns. Part 2.6.2 also allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as load growth. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Oklahoma Gas & Electric	R2.4.3 Not positive what this actually requires Transmission Planner to perform. Recommend compliance with requirement be

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	the responsibility of the Transmission Coordinator. R2.9 OG&E has not provided this information in the past. Different sets of load flow models will result in different data results. Do not see any merit with providing information.
Response: Part 2.4.3 is part of Requirement 2, which applies to both the Transmission Planner and the Planning Coordinator for their respective portion of the BES. So, both are responsible for meeting the requirements even though the actual work may be shared or delegated. Part 2.9 has been deleted in response to industry comments.	
Arizona Public Service Co.	R2.6.2: The wording “study shall not include” is confusing since it refers to the past studies.
Response: Part 2.6.2 has been to address your concerns. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.	
Hydro-Québec TransEnergie (HQT)	Requirement 2.1 As written, it is not clear. HQT, as does NPCC, suggests revising language as in 2.4 as follows:”The Near-Term Transmission Planning Horizon portion of the steady state” analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.1.2 The use of the term “off peak” is a concern. The definition for this term can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.2 As written, it is not clear. HQT, as does NPCC, suggests revising language in 2.2 as in 2.4 as follows: The Long-Term Transmission Planning Horizon portion of the steady state” analysis shall be assessed annually and be supported by current or past studies as indicated in? Requirement R2, part 2.6. The following studies are required: Requirement 2.7 HQT,as does NPCC, suggests changing the word “run” to “condition” in “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3.” Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted.
Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year	

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	study being performed. Therefore, the SDT declines to make the change as suggested. The intent of Part 2.1.2 is to assess those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study. Part 2.7 has been changed to address your concerns. **Requirement R2, part 2.7**: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.9 has been deleted as suggested.
Northeast Power Coordinating Council--RSC	Requirement R2 (second line): "This Planning Assessment shall use current or past studies," should be replaced with "This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6," Requirements 2.1, 2.2, 2.3, and 2.4--As written, are not clear. It is suggested to revise the language as follows: "The Near-Term Transmission Planning Horizon portion of the steady stateanalysis shall be assessed annually and be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required:"Requirement 2.1.2 The use of the term "off peak" is a concern. The definition for this term is not provided, and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Requirement 1.1.2 in the response to Question 1. Requirement 2.1.4: Consistent with the suggestion made for Requirment 1.1.2 remove the last bulleted item in the list under Requirement 2.1.4 "Duration or timing of planned Transmission outages." The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as "an assessment of the impact of this possible unavailability on System performance shall be performed". Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon.

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	Requirement 2.4.2: Same as 2.1.2 Requirement 2.4.3: Refer to the Comment for Question 1 to add a Requirement 1.2 Requirement 2.5: Revise language as follows: be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Requirement 2.7 NPCC suggests changing the word “run” to “condition” so the wording will read Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3. Requirement 2.9 It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.
National Grid	Requirement R2 (second line): This Planning Assessment shall use current or past studies, should be replaced with “This Planning Assessment shall use current studies or qualified past studies as indicated in Requirement R2, part 2.6,” Sub-Requirements 2.1, 2,2, 2,3, and 2.4: Language to be revised to the following:”be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. The following studies are required.”Sub-Requirement 2.1.2: Definition of “off-peak” not provided and can be read to say that it is any load level less than peak. This does not provide enough clarity to guide the required assessments. Sub-Requirement 2.1.3: It must be clarified that the reference to outages as listed in Requirement R1, part 1.1.2 must be limited to Planning Horizon. Refer to Sub-Requirement 1.1.2 in Question 1.Sub-Requirement 2.1.4: Consistent with the suggestion made for section 1.1.2 please remove the last bulleted item in the list under section 2.1.4. “Duration or timing of planned Transmission outages.” The standard is referring to requirements for sensitivity without a reference to base cases. Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.1.5: It needs to be clear that this is only an assessment, not a solution. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. It can be reworded as “an assessment of the impact of this possible unavailability on System performance shall be performed” Sub-Requirement 2.3: The requirement does not indicate a year to study. This should be modified to state that it is up to the Planner to determine the year of study within the Near Term Transmission Planning Horizon. Sub-Requirement 2.4.2: Same as 2.1.2Sub-Requirement 2.4.3: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.5: Revise language as follows:”be supported by current studies or qualified past studies as indicated in Requirement R2, part 2.6. Sub-Requirement 2.7: It is suggested to change the word “run” to “condition” such that it reads “Corrective Action Plan(s) do not

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	need to be developed solely to meet the performance requirements for a single sensitivity condition in accordance with Requirements R2, parts 2.1.4 and 2.4.3." Sub-Requirement 2.7.2: Refer to Comment on Proposal to add an item 1.2 Sub-Requirement 2.9: It should not be necessary to identify the largest consequential load loss if the TPL standard does not limit the size of the consequential load loss. This requirement should be deleted. If it remains, it must be made clear that it be applicable only to Year One or Year Two.

Response: The SDT reviewed Requirement R2, parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The intent of Parts 2.1.2 and 2.4.2 is to support assessment of those System conditions during periods with lower Load levels than peak when the System may show different potential problems than during periods with peak Load level. For example, during light Load conditions, there may be high voltage problems because of the charging in the lightly loaded lines. There could also be thermal overload problems for areas with more generation than Load. The System could have less damping and could result in potential Stability problems. For this reason, it would not be appropriate to eliminate the requirement to investigate Off-Peak steady state or Stability conditions. At the same time, the standard should not be overly prescriptive; therefore, the exact System Off-Peak Load should be specified by the entity performing the study.

Part 2.1.2 – Off-Peak is a defined term in the NERC Glossary.

Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made.

The SDT declines to remove the last bullet in Part 2.1.4, "Duration or timing of planned Transmission outages" as a potential sensitivity. The intent is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. In this case, the System with the equipment in question out of service would be modeled as P0 (or N-0), the next outage would be, for example, P1 (N-1), and not covered in P6.

For Part 2.1.4, the SDT believes that the "base case conditions", on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.

The SDT believes that your concern on Part 2.1.5 has already been addressed. Part 2.7.1 - Corrective Action can include, among other things:

- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.

<table>
<tr><th>Organization</th><th>Comments for Question 2</th></tr>
<tr><td colspan="2">

- Use of rate applications, DSM, new technologies, or other initiatives.

In addition, the first sentence of Part 2.1.5 has been revised.

Requirement R2, part 2.1.5: When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

The SDT believes that this concern has been addressed. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies.

For Part 2.4.3, the SDT believes that the “base case conditions”, on which to base the sensitivity cases, should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. The SDT therefore declines to make the change as suggested.

The existing language in Part 2.5 already allows the assessment to be supported by current or past studies. Therefore, the suggested change is not needed.

Part 2.7 has been changed to address your concerns.

Requirement R2, part 2.7: For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

For response to comments on Part 2.7.2, please see previous response to proposal to add Part 1.2.

Part 2.9 has been deleted due to industry comments.

</td></tr>
<tr><td>Midwest ISO</td><td>

Requirement R2.1.4: It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Also, the use of the following two words “sufficient” and “measurable” are too vague and hard to quantify. This may require an auditor’s opinion. Suggest at least removing the word “sufficient” from the requirements.

Requirement R2.1.5: This requirement states that we need to perform prior outage analysis for P0, P1 and P2 events for all long-lead time (>1year) components without spares. This seems redundant with P3 and P6 which will answer whether those events are an issue. Need to be clear that loss of load is or is not allowed for these events. P2 still allows for some loss of load. Bottom line is that P2.1.5 seems duplicative. What is intent of requirement? Rather say the P3 and P6 should note if long-lead time items are involved without spares. Also, the Planning Coordinator could have an administrative burden demonstrating compliance with a spare equipment strategy for its entire footprint.

Requirement R2.4.3: the use of the following two words “sufficient” and “measurable” are too vague and hard to quantify. This may require an auditor’s opinion. Suggest at least removing the word “sufficient” from the requirements.

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</table>

Organization	Comments for Question 2
	Requirement R2.7.2: As suggested in the comments above for R2.1.4, it should be clarified that corrective actions are not necessary for performance deficiencies identified by sensitivity studies. Request removing this requirement all together. If the SDT agrees to keep this requirement then we offer the following comments: It is not clear how an entity can provide rational for why actions were not necessary. Requirement R2.9: With regards to the largest consequential loss of loads for P1 and P2 events; if no action is required then why require the entities to provide this. Will it matter if 10MW or 100MW is tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R2.9 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: The SDT believes that your concern on Part 2.1.4 is already covered in the existing draft. The existing Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to “Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary”. For Parts 2.1.4 and 2.4.3, The SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity’s spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, for Part 2.1.5, P0 should be modeled with the transformer in question out of service. The performance requirements in Table 1 will apply for the next single Contingency. This is not the same as P2 or P6; both of which are events starting from System intact condition as P0. It is also not the same as P3, which covers loss of a generator as the first event, and Part 2.1.5 covers loss of a piece of major Transmission equipment, for which there is no spare. The words "sufficient" and ‘measurable’ are needed in Part 2.4.3 to ensure that the variations made to the assumptions to investigate sensitivity are large enough to be meaningful so they can demonstrate the impacts of the changes. The SDT envisions that credible sufficient stressed conditions and measurable changes are to be defined by the responsible Planning Coordinator or Transmission Planner. As such, the SDT declines to revise Parts 2.1.4 and 2.4.3 as suggested. The SDT believes that your concern on Part 2.7 is covered in the existing draft. Part 2.7 states, in part, that “Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Duke Energy	Reword R2.1 as follows: The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current studies, supplemented with qualified past studies that meet Requirement R2, part 2.6.

Organization	Comments for Question 2
	The following studies are required: We believe that using a past study for the Long Term Assessment is adequate, as long as the past study meets R2.6. Reword R2.2 as follows: The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be based on the following annual current study or qualified past study that meets Requirement R2, part 2.6. The following study is required: Reword R2.2.1 as follows: System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. We believe that using past studies for the Near-Term Transmission Planning Horizon portion of the Stability analysis is adequate, as long as the past studies meet R2.6. Reword R2.4 as follows: The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be based on the following annual current studies or qualified past studies that meet Requirement R2, part2.6. The following studies are required: R2.5 Does the phrase “proposed generation additions or changes in that timeframe” refer only to generation changes, or does it also refer to transmission system changes?
Response: The SDT declines to make the change to Part 2.1 as suggested because it does not add more clarity than the existing language. The SDT declines to make this change to Part 2.2 and Part 2.2.1. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire Long-Term Transmission Planning Horizon. Making the change as requested can result in no current-year study for the Long-Term Transmission Planning Horizon being performed. Therefore, the SDT declines to make the change as suggested. The SDT declines to make the change to Part 2.4 as suggested because it does not add more clarity than the existing language. Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated.	
NorthWestern Energy	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. The wording in R2.1 is unclear: Are new annual studies required each year or are qualified past studies acceptable if no changes have been made? R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies”

Organization	Comments for Question 2
	Are the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3? Both are for Near-Term studies but for steady state and stability respectively. If they should align, the wording should be modified to be the same. As written R2.1.4, “Real and reactive Load forecasts”, could mean that both Real and Reactive Load forecasts are required. Since most entities only forecast Real (MW) and apply a power factor for reactive (MVAR), wording could be changed to “ forecasted demand and power factor” to clarify that forecasting reactive load is not required.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Therefore, the SDT declines to delete the requirement for short circuit analysis from Requirement R2.

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively.

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

Part 2.1.4 states that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.

Organization	Comments for Question 2
Sacramento Municipal Utility District	SMUD appreciates the diligence with which the SDT has responded to our earlier comments. SMUD offers the following comments on Draft #4 for the SDT's consideration: R2.1.4: To define a “sensitivity” case, the standard should first define a “base” case. If a sensitivity case is a more conservative scenario analysis than a base case, does an entity need to perform/document a Planning Assessment for both “base” and “sensitivity” or is a Planning Assessment that uses the “Sensitivity” case adequate? R2.1: The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies”. R2.1.4 and R2.4.3: The words, “by a sufficient amount” should be removed as it does not provide any more clarity.

Organization	Comments for Question 2
	R2.1.5: The first part of the sentence calls for an analysis of the impact (of modeling the spare equipment strategy). The second part of the sentence that defines the applicable categories to study, starts with the words "The Planning Assessment". Use of the defined words "Planning Assessment", broadens the study to both an impact assessment and providing details of a "Corrective Action Plan". The intent of the requirement should be made clear in the first sentence. R2.4.3: Suggest deleting the words "in the Planning Assessment". Since a corrective action is not required for all sensitivities (see R2.7), use of the defined term in this paragraph can be confusing. R2.6.1: SMUD agrees with allowing a study older than five years to be considered if a technical rationale can be provided. R2.9: The requirement to report the largest single consequential load loss should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies. Table 1 P1.3 and associated Note 5: Is the purpose of the "reference voltage" to determine a valid transformer contingency (thereby, limiting the scope of R2.9)? R2.7 / Table 1, Notes e and i: Note (e) excludes references to load that is allowed to be dropped if it is NOT part of Non-Consequential Load Loss. This note should include such Load (if represented in the load forecast being studied as being part of the Demand Response) if it can be dropped within the time duration applicable to the Facility Ratings. Note (i): Since the definition of Non-CLL would allow interruptible load to be dropped, is note (i) stating that interruptible load cannot be dropped even if it meets the "executable within the time duration' requirement"

Response: For Part 2.1.4, the SDT believes that the "base case conditions" on which to base the sensitivity cases should be defined by the entity performing the study. Sensitivity studies are performed to provide insight into the impacts of potential variations of assumptions in studies. It is also up to the entity performing the study to determine the scenarios to be used for the Planning Assessment.

The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.

For Parts 2.1.4 and 2.4.3, The SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.

Part 2.1.5 is part of Requirement R2, which requires that each Transmission Planner and Planning Coordinator prepare an annual Planning Assessment of its portion of the BES, therefore, the use of Planning Assessment in Part 2.1.5 has not broadened the requirement. The first sentence of Part 2.1.5 has been revised to provide more clarity.

Requirement R2, part 2.1.5: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of

<table>
<tr><th>Organization</th><th>Comments for Question 2</th></tr>
<tr><td colspan="2">one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

For Part 2.4.3, the SDT declines to delete “in the Planning Assessment” as suggested because Part 2.4.3 is part of Requirement R2, which covers the requirement of preparing an annual Planning Assessment.

Part 2.9 has been deleted as suggested.

Table 1, P1.3 and associated footnote 5: the term “reference voltage” is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV transformer is outaged for the event studied the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility; your regional entity organization definition of the BES should be consulted for an official position.

Note (e) in Table 1 refers to “planned System adjustments” and “Transmission configuration changes and re-dispatch of generation” are examples of “planned System adjustments”. Table 1 note (i) is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.</td></tr>
<tr><td>US Bureau of Reclamation</td><td>The conflict is created in Section 2.5 in that only proposed generation additions or changes are assessed in "Long-Term planning Horizon portion of the Stability analysis. This Section should also address proposed transmission facility additoins or changes.

Section 2.7 indicates that the Planning Assessment shall include Corrective Action Plan(s) addressing how performance requirements will addressed. This implies that the Corrective Action plans are not proposed generation or transmission additions or changes. If Corrective Action Plan items are developed through Planning Assessments, they should be clarified as proposals for consideration by Generator Owners and Transmission owners in developed future system modifications or additions.</td></tr>
<tr><td colspan="2">Response: Part 2.5 is intended for investigation of Stability issues due to addition of generators. The SDT does not believe that, in general, a Stability assessment is needed for the Long-Term Transmission Planning Horizon. The System model for that timeframe is too uncertain for a meaningful assessment of the System's Stability. However, for those situations where a specific generator is planned to be added in that timeframe, the SDT believes that it will be appropriate to require that the generator's Stability impact be evaluated. However, the standard does not preclude investigation of addition of other Facilities, such as Transmission Facilities.

Part 2.7 does not imply that “the Corrective Action plans are not proposed generation or transmission additions or changes”. Part 2.7.2 includes a list of actions that can be included as part of a Corrective Action Plan, which the Transmission Planner and Planning Coordinator are required to prepare.</td></tr>
<tr><td>TIS</td><td>The reference in R2.1.3 to the outage schedules as listing in part R1.1.2 must be recognized as a limitation to the standard to the Planning Horizon. See the TIS comment tor R1.</td></tr>
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Organization	Comments for Question 2
	There is confusion in interpretation of the Table 1 When the voltage class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied? For example if a SLG fault is on a 138-kV element or a 345/138-kV autotransformer, are you allowed to shed load to keep a345-kV element from overloading? Conversely, if the fault is on a 345-kV element, are you allowed to shed load to keep a 138-kV from overloading? It should be the voltage level of the overloaded element (not the outaged element) that determines whether or not non-consequential load shedding is allowed. The TIS believes that the requirement to report the largest single consequential load loss under Requirement 2.9 should not be included in the standard. If it remains, it must be made clear that it be applicable only to Year One, and there should be additional clarification that the requirement to report consequential load loss (single number) is ONLY for the most severe contingencies studied for the P1 and P2 contingencies.
Response: Part 2.1.3 is a sub-part of Part 2.1 which is limited by the Near-Term Transmission Planning Horizon so no change is made. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted as suggested.	
Idaho Power	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies"?, while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies"? to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Response: The SDT reviewed Requirement 2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be	

Organization	Comments for Question 2
flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that at least parts of the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
Modesto Irrigation District Transmission Planning	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies” It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required.R2.1.4, R2.4.3 "... vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measureable change in performance." Please define measureable. An example would certainly help. This would be a good workshop item to show how to perform. R2.6.2 The previous version defined material change. This current version eliminated the definition of material change, but still indicates the study shall not include any material changes.... This is unclear; please clarify.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement	

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the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. For Part 2.4.3, the SDT envisions that "measurable change" is to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT agrees that a workshop is a good idea. However, because of differences in each Region/Interconnection, the SDT encourages the Regions to hold workshops on issues specific to the Regions utilizing SDT members as participants in the discussions. Part 2.6.2 allows an entity to rely on a past study with a material change if "a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area". Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.	
NV Energy	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
Pacific Gas and Electric Co.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the

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	intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
San Diego Gas & Electric Co	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.
SRP	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies" It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required.

Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission

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Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast.	
Puget Sound Energy, Inc.	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads “This Planning Assessment shall use current or past studies”, while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies” to “The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies” The wording in R2.1.1 is unclear as to whether two studies are required or only one. Should it read “year one or year two or year 5” as opposed to “year 1 or year 2 and year 5”? The language in 2.3, indicating that short circuit analysis be studied as part a BES transmission planning assessment should not be required. The effects of the failure of over-stressed breakers are already included in the Events listed in Table 1. Examples would include P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). The addition of short circuit analysis study does not add any additional reliability information. It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change “real and reactive load forecast” to “forecasted demand and power factor” so it is clear that forecasting reactive load is not required. R2.9 should be deleted (or not required for local load loss). The SDT indicated in the response to “Consideration of Comments on 3rd Draft of Standard TPL-001-1” that the requirement R2.9 is intended to “contribute to an open and transparent Transmission planning for peer review.” And if the “largest Consequential Load Loss” is a local (intra-network) event? Would the documentation of such an event contribute to reliability in any way?
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require “annual current year study, supplemented by qualified past studies”. Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of	

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the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. Part 2.1.1 is intended to cover both the timeframe just after operation planning (Year One or year two), as well as the timeframe to allow implementation of solutions, which may require a longer lead time. Therefore, the "Year 1 or year 2 and year 5" in Part 2.1.1 is correct as written. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. Part 2.9 has been deleted as suggested.	
Southern California Edison (SCE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. We suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. Additionally, 2.4.2 is inconsistent with 2.4.1 with regards to language. It seems the intent of the Standards Drafting Team was to have the two consistent with each other. Specifically, the quote below, from section 2.4.1, is missing from section 2.4.2 (keeping in mind the word "peak" should be replaced with "Off-Peak"."System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable."

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Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of the basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. In Part 2.4.1, the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during Off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1.	
Utility System Efficiencies, Inc. (USE)	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizons, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested.	

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The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities	
Western Area Power Adm - RMR	The wording in R2.1 is unclear as to whether new annual studies are required each year or whether qualified past studies are acceptable if no changes have been made. R2 reads "This Planning Assessment shall use current or past studies", while R2.1 implies current studies must be used but can be supplemented by past studies. I suggest changing the wording from "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, supplemented with qualified past studies" to "The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current studies, or qualified past studies"? It is unclear if the drafting team intended the sensitivity studies identified by the bullets in R2.1.4 to align with the sensitivity studies identified by the bullets in R2.4.3. Both are for Near-Term studies but for steady state and stability respectively. If the intent is that they align, the wording should be modified to be the same. Also, similar to R1.1.4 above, R2.1.4 could be interpreted that the standard requires forecasting reactive load. However, most entities forecast demand (MW) and apply a power factor(s) to calculate reactive load. Therefore, please change "real and reactive load forecast" to "forecasted demand and power factor" so it is clear that forecasting reactive load is not required. In R2.1.5 " the opening statement "When an entity's "spare equipment strategy" Does this imply an auditor would ask for this documentation as part of the review of this new TPL-001? Also " what other Standard requires the "spare equipment strategy"? I'm trying to determine what kind of documentation is required for this Requirement.
Response: The SDT reviewed Requirement R2 and Parts 2.1 through 2.5. Only Parts 2.1 and 2.2 require "annual current year study, supplemented by qualified past studies". Parts 2.1 and 2.2 cover steady state studies in the near-term and the long-term planning horizon, respectively. While the SDT envisions the standard to be flexible enough to allow the use of qualified past studies, the Planning Assessment cannot be based entirely on past studies. Because steady state analysis is part of basic planning process, the SDT believes that the steady state portion of the studies covering Year One or year two and year five for the Near-Term Transmission Planning Horizon and one of the years in the Long-Term Transmission Planning Horizon should be done annually. Qualified past studies can be used to supplement the studies for the remaining study years to support the assessment for the entire planning horizon. Making the change as requested can result in no current-year study being performed. Therefore, the SDT declines to make the change as suggested. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities Parts 1.1.4 and 2.1.4 state that a reactive forecast is required. Using a power factor is one method that may be used in calculating this reactive forecast. Part 2.1.5 does not require a spare equipment strategy. It only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare	

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transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning study. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should also be modeled with the transformer in question out of service. The SDT cannot comment on what documentation an auditor would need to support an audit.	
SRC of ISO/RTO	Under 2.1.4- It should be made clear that the sensitivity findings do not obligate the PC or TP to establish Corrective Action Plans to address any needs identified in the sensitivity cases. Specifically, we do not believe the sentence "To accomplish this, the sensitivity analysis in the Planning Assesment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance." is measurable or necessary. The first part of 2.1.4 already stipulates sufficient details for the responsible entity to conduct sensitivity analysis including the parameters to be varied. Adding the "how-to-conduct" requirement is overly prescriptive and unnecessary, and the condition for "that demonstrate a measurable change in performance" is not measurable. It lacks a definitive target or direction for the responsible entity to determine (a) what conditions need to be attained to demonstrate a measurable change in performance, (b) what constitutes "measurable change in performance", and (c) what follow-up or corrective actions are needed to address the adverse performance as a result of stressing the system beyond the forecast conditions. Under 2.1.4 and 2.4.3 "sufficient" and "measurable" are too vague and hard to quantify. This may require an auditor's opinion. Suggest removing at least the word "sufficient" from the requirements. Under 2.3- Some PCs do not perform short circuit analysis. Is it the intent of the SDT to make the analysis standardized over a footprint? Alternatively, this could be a TP only responsibility. Further, Part 2.3 stipulates the short-circuit assessment requirements for the near-term horizon. Unlike its steady-state and stability counterparts, there are no requirements stipulated for short-circuit analysis for the long-term horizon. Is this intentional? If so, we are unable to identify the rationale for this decision. If not, we suggest revising Part 2.3 to: "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the near-term and long-term Transmission Planning Horizons and can be supported by...". Under 2.7.2, it is not clear how an entity can provide rational for why actions are not necessary. If actions are not necessary, then no rationalizing is needed. Further, as stated above, corrective action plans should not be required for sensitivity studies. R2.7.2 should be struck. We propose to remove R2.9, since there is not a reliability need for this information and it is unnecessary. AESO does not comment on VSLs or VRFs.
Response: For Part 2.1.4, the requirement for Corrective Action Plans to address any needs identified in the sensitivity cases is included in Part 2.7. Part 2.7 states, in part, that "Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. In addition, Part 2.7.2 describes the requirement on Corrective Action Plans to "Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary". For Parts 2.1.4 and 2.4.3, the SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different.	

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Part 2.3 is intended for the Planning Coordinator and Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. The standard allows the Planning Coordinator and Transmission Planner to coordinate on who would perform short circuit studies. But each is still responsible for meeting the requirements. Part 2.3 is for short circuit assessment of the system in general and is more suited for the Near-Term Transmission Planning Horizon, when Transmission plans are more certain. Lead time to implement corrective action if found necessary can reasonably be expected to be completed in the near-term timeframe. Short circuit study for the longer term planning horizon should be studied on a case by case basis associated with specific project(s). The SDT disagrees that Part 2.7.2 should be struck. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
Exelon Transmission Planning	We believe that the Table 1 performance criteria should be based on the voltage level of potentially overloaded elements and not based on the voltage level of the element(s) removed from service. If a 100 kV line were overloaded for a 500 kV contingency, it does not make sense to us to treat it differently than if the same overload occurred for a 100 kV contingency since the severity of the event is the same in both cases. The availability of load shedding to reduce overloads on EHV equipment and not for overloads on HV equipment makes sense since typically a greater amount of load would need to be shed to unload an EHV facility than an HV facility. We disagree with the requirement to report the largest amount of consequential load loss. If this information is not used to meet a requirement adding to reliability, it is creating undo burden. If the requirement is kept, it should be made clear as to which case or cases the requirement pertains. The Planning Assessment will contain extremely sensitive information. The threshold that it must be supplied to ANY functional entity is too low. There should be a CEII or other process to ensure that this information is adequately protected.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Table 1, footnote 1**: If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Part 2.9 has been deleted based on industry responses.	
American Transmission Company	We propose the following changes and following questions:New R2.1 We suggest that R2.6 be relocated to the R2.1 position to allow the preferred style of backward references to text that occurs earlier in a document, rather than forward references to text that appears later in a document.

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	R2.1.3 As noted above, we suggest that R1.1.2 be removed and that R2.1.3 be revised to state that “Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur.” We interpret that simulation of known outages of at least six months should refer only to individual outages with duration of six months or more have to be simulated and not a set of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the set is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping that the outage would be simulated as simultaneous for the System peak or Off-Peak conditions when the overlapping outages are scheduled to occur. R2.1.4 The terms of “credible” and “measurable change” are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.1.4 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to “Expected transfers and other generation dispatch scenarios”. This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the “generation dispatch” (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 We propose replacing the adjective “planned” with “known” for consistency with R2.1.3 and any other “known” references in the standard. R2.1.5 We propose replacing the term “major Transmission” with “BES” because BES is a well defined term, while “major Transmission” is not. New R2.3.1 We suggest the addition of new R2.3.1 to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. R2.4.1 - The terms of “study area” and “represents” are ambiguous and not defined. Therefore, we suggest that these terms be more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R2.4.3 The terms of “credible” and “measurable change” are ambiguous and not defined. Therefore, we suggest that these terms be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors.R2.4.3 bullet items We suggest that the number and description of the bullet items in R2.1.4 match the bullet points in R2.1.4. Otherwise, please explain the reasons for any differences. R2.4.3 bullet #2 & # 5 We suggest that the wording of bulletin #2 be changed to “Expected transfers and other generation dispatch scenarios”. This would place these similar items in the same bullet item #2, rather than having the “other generation dispatch” in bullet item #5.

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	R2.4.3 bullet #3 We suggest that the wording of "new or modified Transmission Facilities" to agree with the wording in bulletin #3 of R2.1.4. R2.6 As noted earlier, we suggest that the numbering of this requirement be changing it to R2.1 to avoid the style of forward references. Add R2.7.1 Item #7 - We propose the addition of the following bullet item to R2.7.1 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. Item #7 could read, "Planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration of the Facility Ratings." Note "e" in the Planning Events, Steady State & Stability section is stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (and basically hidden) in the performance notes of Table 1. [After bullet item #7 is added, Note "e" under "Steady State & Stability section of Table 1 should refer to R2.7.1] R2.7.2 " We suggest using the term, "mitigation actions", to more clearly distinguish that this requirement is not asking for the development of "Corrective Action Plans", such as those that are needed for inability to meet base case performance requirements.R2.7.6 We suggest that the wording of R2.7.6 be the same as R.2.8.2. Otherwise, we propose that R2.7.6 and R2.8.2 be revised with wording like, ". . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures." to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year's Corrective Action Plans. R2.9 We still propose that this requirement be removed because annually stating the single, largest expected, Consequential Load Loss due to a P1 or P2 event in the TP or PC system is not needed to provide reliable BES performance or assure open and transparent Transmission planning peer review.

Response: The SDT reviewed the order of Parts 2.1 and 2.6 and declines to modify it as suggested because it does not add additional clarity.

Part 2.1.3 covers known long duration outages, for example, taking a 230 kV Transmission line out of service to rebuild it to operate at 500 kV. These cases are to simulate System conditions with the Facility in question out of service as Category P0 (or N-0). For the next outage, the System performance will need to meet requirements for Category P1. This is not the same as requirements for Category P6, which assumes that the outage for the first Facility would be of shorter duration than 6 months. Part 2.1.3 has been revised to read "P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled" to provide more clarity. The SDT agrees that if two or more known outages with duration of at least six months are overlapping that the outage should be simulated as simultaneous for the conditions when the overlapping outages are scheduled to occur. This is consistent with the requirement to simulate the System conditions as it is expected to operate.

For Parts 2.1.4 and 2.4.3, the SDT envisions that "credible", "sufficient", "stressed" conditions and "measurable change" are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and Stability evaluations, respectively.

Requirement R2, part 2.4.3, **bullet #3**: Expected in service dates of new or modified Transmission Facilities

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The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. In Part 2.1.4, bullet #7, the SDT declines to replace “planned” with “known” as suggested in “Duration or timing of planned Transmission outages”. Part 2.1.4 covers sensitivity scenarios and reflects uncertainty in planning assumptions. The intent of this bullet is to cover unexpected changes in plans, for example, a potential delay in returning a Transmission line back to service after a planned outage of 6 months or more for rebuilding to a higher capacity line. If the outage is “known”, then there would not be any need to perform this study as a sensitivity. In Part 2.1.5, the SDT declines to replace the term “major Transmission equipment” with “BES equipment” because the intent is to investigate the unavailability of major pieces of equipment in the Transmission System. Transmission is defined in the NERC Glossary as, “An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems”. Part 2.3 is silent on the year of study within the Near-Term Transmission Planning Horizon. Therefore, it is up to the Transmission Planner or Planning Coordinator to select the study years most suited to the System in question. In addition, Part 2.3 only requires an annual Planning Assessment, which is to be supported by annual current or qualified past studies. As such, the SDT believes it is inappropriate to make the change as suggested Part 2.4.1: The SDT believes that the terms of “study area” and “represents” should be defined by the Planning Coordinator or Transmission Planner performing the study, and should be part of the coordination between the entities. For Parts 2.1.4 and 2.4.3, The SDT envisions that “credible”, “sufficient”, “stressed” conditions and “measurable change” are to be defined by the responsible Planning Coordinator or Transmission Planner because each System is different. The SDT reviewed Parts 2.1.4 and 2.4.3. The third bullet in Part 2.4.3 has been modified. The remaining differences between the two parts are intended. The SDT developed the lists contained within Parts 2.1.4 and 2.4.3 to address those situations which it believed were the most relevant for the steady state evaluations and stability evaluations, respectively. **Requirement R2, part 2.4.3**, **bullet #3**: Expected in service dates of new or modified Transmission Facilities The SDT declines to change the second and fifth bullets in Part 2.4.3 because the existing arrangement will keep the generator scenarios together. Expected transfers are not always associated with generation dispatch. The SDT reviewed the order of Part 2.1 and Part 2.6 and declines to modify it as suggested because it does not add additional clarity. Note e in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch. Part 2.7.1 is a list of examples, so it could include more items than listed, including Note e in Table 1. The SDT declines to make the suggested change. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. Part 2.9 has been deleted as suggested.	
PJM	R2 should use the term –dynamics analysis- instead of –stability analysis-. A dynamics study is used to determine stability like a power flow study is used to determine overloads or voltage violations. In R2.1.1 is -System peak Load- seasonal peak load or the peaking season of that region? For example, if I’m a summer peaking

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	region, must I do a summer peak study and a winter peak study or just a summer peak study? In R2.1.3, change -for known outages, as modeled in- to –with known outages modeled, as required in-. R2.1.5 should be made clear that only one piece of equipment should be taken out at a time for each sensitivity. No matter what FERC says, this requirement should be deleted because this analysis serves no purpose. If a spare equipment strategy is required, please tell us so in a spare equipment standard, not hidden here in a performance standard. R2.4.3 – Please delete the words -for the list of items shown below- at the end of the first sentence. There is an implication in this sentence, as originally worded, that a sensitivity must be performed for the entire list of sensitivities instead of how it is explained in the second sentence. R2.6.2 – Please reword -the study shall not include any material changes- to –a study with material changes shall not be used- The old sentence sounded like you just exclude the material changes and you are good to go. R2.7.1 – Please change -List System deficiencies- to –List performance deficiencies-. R2.7.1 – 3rd Bullet – I would lump this under Special Protection Systems, also why is runback not allowed for dynamics problems, seems there are some restrictions buried here. R2.7.1 – 6th Bullet – What is a –rate application-? R2.7.2 – This is pushing us to plan the system for scenarios that may never happen. Pushing us to some higher level of reliability will cost significant money. Should the ratepayers be burdened with this excess? I say no, remove this requirement. R2.8.1 – Change -List System deficiencies- to –List short circuit deficiencies-.

Response: The SDT declines to replace "Stability analysis" with "dynamic analysis" because it does not add additional clarity.

The intent of Part 2.1.1 is to assess those System conditions under peak Load conditions when the System is reasonably stressed. It is envisioned that the Planning Coordinator or Transmission Planner will determine the System conditions for its planning studies.

Part 2.1.3 has been revised as suggested.

> **Requirement R2, part 2.1.3**: P1 events in Table 1 with known outages modeled, as in Requirement R1, part 1.1.2 under those System peak or Off-Peak conditions when known outages are scheduled.

Part 2.1.5 only requires that the Planning Coordinator or Transmission Planner plans for the potential unavailability of long lead time major Transmission equipment in accordance with its spare equipment strategy. For example, if an entity's spare equipment strategy is to have a spare transformer on site, then the unavailability of a similar transformer (due to outages) would be limited to the time it would take to energize the spare transformer. Assuming that this time is no more than that required to return a similar outaged transformer back in service, Part 2.1.5 can be satisfied without performing additional planning studies. If on the other hand, the transformer would have to be purchased, then it would take more than a year to replace. In this case, P0 should be modeled with the transformer in question out of service.

Part 2.4.3 has been revised as suggested.

> **Requirement R2, part 2.4.3**: For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of

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the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: Part 2.6.2 has been revised as suggested. **Requirement R2, part 2.6.2**: For steady state, short circuit, or Stability analysis: the System represented in the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to revise Part 2.7.1 as suggested because it does not add additional clarity. The SDT declines to combine the third bullet with Special Protection Schemes (SPS) because automatic generation tripping does not always have to be part of an SPS. In any case, this list contains examples only. It is envisioned that run-back would take a longer time period and would not fit in the transient Stability study period. Part 2.7.1, sixth bullet, "rate application" can be regulatory incentives, such as demand response, distributed generation, etc. Part 2.7.2 provides for development of a Corrective Action Plan if a number of sensitivity studies result in the same potential problem. For example, if only one sensitivity study results in potential problems or if the probability of occurrences of the sensitivity scenarios is low, then this could be the rationale to state that corrective action plan would not be necessary. In addition, Part 2.7.1 allows the use of lower cost alternatives, such as operating procedures, among other things to correct potential performance deficiencies identified. The SDT declines to revise Part 2.8.1 because the language as written is clear.	

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has modified the wording of several parts of Requirement R3 to increase clarity as requested by many industry comments and shown below. Requirement R3, part 3.6 was deleted in response to industry comments as it is not a performance oriented requirement.

Requirement R3, part 3.3: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded.

Requirement R3, part 3.5: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

Requirement R3, part 3.6:

Requirement R3, data retention: The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3**.**

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Independent Electricity System Operator	(1) R3 has become more of a “how to” requirement than a “what” requirement, as illustrated below. (a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration. (b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one asked the question: will reliability be adversely affected if the responsible entity failed to document the list and the rationale for choosing this list? If the answer is no, then they don’t rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning events in Table 1 would suffice. Table 1 already stipulates the events that must be considered in the analysis. We do not see the need to go into such details as “some events are expected to produce more severe impacts”, and the need to ask the planners to

<table>
<tr><th>Organization</th><th>Comments for Question 3</th></tr>
<tr><td></td><td>create a list of these more impactive contingencies for subsequent evaluation. Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale.

(2) We have no comments on the measure, VRF and Time Horizon. However, there is no VSL for Part 3.6.</td></tr>
<tr><td colspan="2">Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made.

Part 3.4 & Part 3.5: Require the planning entity to identify which Contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made.

Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.

VSL for Part 3.6: The SDT has deleted Part 3.6.</td></tr>
<tr><td>ERCOT ISO</td><td>* Will any agreements made in R7 override the “each TP and PC” requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "*

Section 3.1 and 3.4 appear to be related. Confusing references can be eliminated by combining them and removing 3.4 as follows: "3.1. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information".*

Similarly, Section 3.2 and 3.5 appear to be related. Confusing references can be eliminated by combining them and removing 3.5: "3.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted A list of the events and the rationale for those Contingencies selected for evaluation shall be available as supporting information."</td></tr>
<tr><td colspan="2">Response: R7: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planner. The SDT believes this is clear in the existing language. No change made.

Parts 3.1 & 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made.

Parts 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made.</td></tr>
<tr><td>Northeast Utilities</td><td>[R3.3.2] Traditionally, transmission planners have assumed that generators would ride through low voltages associated with Planning Events, which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be a MOD standard developed requiring the generator owners to provide the necessary</td></tr>
</table>

Organization	Comments for Question 3
	information prior to its inclusion as a requirement in this standard. [R3.3.3] This requirement is already addressed in NERC Standard PRC-023 and reflected in facility ratings and therefore, should be removed from TPL-001-1. [R3.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended: It should be clear that an evaluation does not require solution development for all Extreme Events. Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered." [R3.6] Why the need to report the amount of "Consequential Generation Loss" since TPL-001-1 does not impose any limit or reliability consequence? We recommend that this requirement be deleted from the standard.
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made for this comment. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Central Maine Power Company	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
ISO New England	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
United Illuminating	3.2 Item 3.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 3.3.2 This requirement is not practical unless a MOD is created so that known minimum generator steady state or ride through voltage limitations are used instead of assumed values. To create a MOD, collect the data, and incorporate the information into the studies will take time, which necessitates the need for an implementation period. Absent accepting this suggestion with respect to creating an MOD, please provide assumed minimum generator steady state or ride through voltage limitations as a standard reference for this analysis. 3.3.3 There appears to be a compliance double-jeopardy issue related to relay loadability. Relay loadability is handled in

Organization	Comments for Question 3
	greater detail (as it should be) under the proposed PRC-023 standard, so any reference here should be deleted. 3.4 It is suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 Item 3.6 should be deleted since there is no limit defined in the standard.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: Part 3.6: The SDT has deleted part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Municipal Power Agency, and its Member Cities	3.3.1, is the intent of the SDT that extreme events that may cause loading beyond relay trip settings (especially Zone 3) be simulated? There is no need for 3.3.3 since the Facility Ratings should already take this into account (FAC-008, R1.2.1 The scope of equipment addressed shall include, but not be limited to, " relay protective devices, "). This adds unneeded burden to transmission planners in developing evidence for this that already exists elsewhere. In other words, by respecting Facility Ratings, we respect relay loadability.
Response: Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events)	

Organization	Comments for Question 3
and 3.5 (extreme events). Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
Oncor Electric Delivery	3.3.2 Do we want to be able to trip gen? 3.3.3 Relay loadability covered in PRC-023 3.6 Why is this information reported if there is no limit or reliability consequence. 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1. 3.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the "evaluation of possible actions." 3.5 It is strongly suggested that this be made a sub-bullet of Requirement 3.2 to keep the related requirements together. 3.6 It is recommended that the "consequential generation" loss is excluded from the amount documented. [Why?]
Response: Part 3.3.2: In order to ensure performance requirements are met in cases where System conditions could cause a generator to trip, Requirement R3, part 3.3.2 requires that the entity trip a generator at locations where bus voltages in the simulation fall below known or assumed generator steady state or ride through voltage limits. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Parts 3.5 & 4.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	

Organization	Comments for Question 3
FirstEnergy Corp	A. The inclusion of sub-part 3.3.3 of Requirement R3 that reads "Ensure relay loadability limits are respected" is not needed as it is duplicative with standard PRC-023, and indirectly redundant with the facility rating standards FAC-008 and FAC-009. Additionally, the introductory notes of performance Table 1 item "f" is clear that Facility Ratings shall not be exceeded and PRC-023 makes it clear that relay loadability must be accounted for in Facility Ratings. In NERC's three-year assessment, Attachment 2 it clearly indicates that one goal of NERC's standards development work plan is " ...retiring redundant requirements ..." (Please reference page 4, the 6th bullet under plan objectives). To that end, we should not knowingly create redundant requirements that lead to double jeopardy issues for industry stakeholders. If a "belts and suspenders" is the goal here, it's suggested that a footnote be added to item "f" of the introductory notes that would clarify that PRC-023 must be adhered to with regard to Facility ratings. B. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES, then the transmission voltage should be the reference voltage. Either way, the reference point should be consistent. In addition, 3.3.2 requires the unit to be tripped. It should be noted that the minimum voltage point may be overly-conservative, since the minimum voltage that a unit can stay on line is MVA output dependent. For base load units, determining a generator minimum voltage should be relatively straightforward, however, peaking and regulating units, not so. Our experience has been that generating units at manned locations generally do not have undervoltage protection or alarms, so FE is not certain how this Requirement to trip those units matches the "real world". C. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 3.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent System contingencies expected to produce the more severe System impacts on their system. In fact, sub-part 3.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 3.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.

Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded.

Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made.

Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the planners system. No change made.

Organization	Comments for Question 3
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all

Organization	Comments for Question 3
	appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy recommends references to "Long-Term Transmission Planning Horizon" be revised to contain comparable language as in the existing TPL standards that limit Long-Term studies to marginal system conditions requiring longer lead times. See CenterPoint Energy's comments regarding part 2.2 for the rationale behind this recommendation. CenterPoint Energy also recommends deleting part 3.4.1 as being overly prescriptive and difficult to demonstrate in an audit.
Response: Long-Term Transmission Planning Horizon: The SDT believes there is value in taking a long range view in planning to assess the general trend. Since the Long-Term planning horizon is year 6 – year 10, the Planning Coordinator or Transmission Planner can for example, select year 6 in the Long-Term Planning Horizon and then use this study as the past study to supplement the Near-Term year 5 study requirement the following year. No change made. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made**.**	
ITC Holdings	Comments: Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such "standards", it will be difficult to justify CAPs based on LVRT assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R3.4.1 (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine	

Organization	Comments for Question 3
if the performance requirements are met for the initiating event and subsequent generator trip. No change made. If tripping of a generator results in performance which does not meet the requirements in Table 1, Requirement R2, part 2.6 requires the planner to develop a Corrective Action Plan. The allocation of costs to implement such a plan is beyond the scope of this standard. The SDT has decided not to include a requirement for high voltage ride through. Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent Systems that could impact the planners System. No change made. The SDT believes that the methodology for determining the appropriate Contingencies in the adjacent Systems is best left to the judgment of each planner. This could include Contingencies from all planning event categories (P1 to P7) if it is judged they could have an impact. Similarly, the neighboring System would select categories in adjacent Systems to study. The requirement does not mandate joint studies. If a performance deficiency is found in the planner's System due to a Contingency in an adjacent System, it is up to the planner in whose System the deficiency exists to develop the CAP. Cost allocation for the CAP is beyond the scope of this standard.	
FRCC Transmission Working Group	Comments: With regard to the Moderate VSL, consider deleting "utilizing data" in order to avoid penalizing twice for failing to meet R1. Please provide clarity to 3.3.2 which states that a Planning Assessment "it must perform simulation that show generator ride through voltage limitation". However, ride through is only performed through stability simulation.The references within the requirements are very confusing. 3.1 refers to a contingency list created in 3.4 which refers back to 3.1. Similarly 3.2 refers to a contingency list created in 3.5 which refers back to 3.2. These should be combined into one requirement bullet. Please provide clarity to 3.3.1. Is the intent of the drafting team that extreme events that may cause loading beyond relay trip settings (zone 3) be simulated?
Response: VSL: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-Contingency steady-state where the planner would know if post-contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Parts 3.1 & 3.4; 3.2 & 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3.1: The intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). Requirement R3, Part 3.3 wording has been modified to add to clarify the intent. **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Gainesville Regional Utilities	Even though I do assess my portion of the BES, I do so, not in an isolated, detached vacuum, but in light of its active connection to the rest of the FRCC Region and how, if at all possible, my small system could in any way be determined at the region level

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	to have any impact in any of the functional areas of the entire region. So the requirements in this section are considered and assessed as “a part of the whole”.
Response: As you have not referenced a specific section, the SDT can not provide a response.	
Utility System Efficiencies, Inc. (USE)	For clarity I suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Bonneville Power Administration	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Idaho Power	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.
NV Energy	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.”
San Diego Gas & Electric Co	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Southern California Edison (SCE)	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits."
SRP	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.”
Western Area Power Adm - RMR	For clarity, I suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.”
Deseret Power	Comments: For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded.	
TVA System Planning	In R3.3.3, TVA believes that relay loadability is already covered in PRC-023. TVA is concerned that including this requirement could result in possible double jeopardy if a utility was found non compliant with PRC-023. Is the SDT proposing that relay

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	loadability be covered for all BES facilities or just those facilities identified in PRC-023?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. The SDT intent is that Requirement R3, part 3.3.3 applies to those BES elements where relay loadability limit is defined by PRC-023.	
Modesto Irrigation District Transmission Planning	For clarity we suggest that the wording in R3.3.3 be changed to “Ensure the power flows in the simulations are no higher than actual relay loadability limits. Also please define relay loadability limit.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. R3.3.3: Relay loadability is defined in PRC-023-1.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R3 and M3 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support”. The word in all caps is a word suggested to be added.
Response: Data Retention: The SDT agrees with your suggestion. The wording in “data retention” for R3 has been changed. Measure M3 already use the word “the”. **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
Progress Energy Carolinas	PEC believes that R3.3.3 "Ensure relay loadability limits are respected" is unnecessary. The requirement to stay within Facility Limits is much more bounding. Several footnote references from Table 1 to the footnotes are incorrect.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Table1: The SDT has corrected the footnote references.	

<table>
<tr><th>Organization</th><th>Comments for Question 3</th></tr>
<tr><td>Oklahoma Gas & Electric</td><td>R 3.4, R3.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.</td></tr>
<tr><td colspan="2">Response: Parts 3.4 & 3.5: The SDT assumes that the Planning Coordinator/Transmission Planner applying experience of past studies and knowledge of its System is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingencies. No changes made.</td></tr>
<tr><td>SRC of ISO/RTO</td><td>R3 has become more of a "how to" requirement than a "what" requirement as illustrated below.

(a) Part 3.3 is overly prescriptive. A requirement that says contingency analysis shall be performed which reflect proper operation of all Protection Systems and actions of all automatic devices would suffice. If necessary, some examples such as those listed in Part 3.3.4 may be added as illustration.

(b) The parts that ask for creating a list of contingencies and having rationale available as supporting information, in Part 3.4 for example, are overly prescriptive and unnecessary. These are documentation requirements, not reliability requirements. If one ask the question: Will reliability be adversely affected if the responsible entity failed to document the list and teh rationale for choosing the list? and the answer is no, then the requirement does not rise up to a reliability standard. To meet the intent of Part 3.4, a simple requirement that asks the responsible entity to demonstrate acceptable system performance for the applicable planning event in Table 1 would suffice. Table 1 already stipulates the event that must be considered in the analysis. We do not see the need to go into such details as "some events are expected to produce more severe impacts...", and the need to ask the planners to create a list of these more impactive contingencies for subsequent evaluation.

Similar observation is made for Part 3.5 on the extreme event list and for Part 3.6 for the amount of generation loss, and the rationale.

AESO does not comment on VSLs or VRFs></td></tr>
<tr><td colspan="2">Response: R3: The SDT disagrees with the comment. The parts of Requirement R3 specify the components required for a compliant study. No change made.

Part 3.4 & Part 3.5: Require the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. No change made.

Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.

VSL: The SDT does not understand the reference to AESO.</td></tr>
<tr><td>Manitoba Hydro</td><td>R3.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.</td></tr>
<tr><td colspan="2">Response: Part 3.2: SDT does not believe clarity is improved by adding the word "contingency" to the word "list". No change made.</td></tr>
</table>

Organization	Comments for Question 3
MRO NERC Standards Review Subcommittee	R3.3.1 Revise the wording to add, ". . . including the simulation of transmission circuit loadability protection." The Protection System actions should be included in this requirement regarding proper Protection System simulation, rather than as a separate requirement in R3.3.3. Otherwise there would be in double jeopardy of violating R3.3.1. and R3.3.3 when circuit loadability protection is not properly simulated. R3.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, The MRO NSRS suggests that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions. Add R3.3.5 The MRO NSRS suggests the addition of R3.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 The MRO NSRS suggests the addition of R3.3.6, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.4.1 The MRO NSRS suggests that the word "coordinate" and the reference to the Transmission Planner be removed and offer the following revised text, "the Planning Coordinator shall provide the list of contingencies that are simulated in the adjacent Planning Coordinator area to the respective Planning Coordinator for review and feedback.". Standard Drafting Teams are generally instructed not to use the word "coordinate". The MRO NSRS suggests that this requirement apply to the PC because the PC would share with any affected Transmission Planners. R3.6 The MRO NSRS suggests the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System. M3 & R3 Data Retention - The MRO NSRS proposes that the wording in these elements be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data

Organization	Comments for Question 3
	retention would read as follows: "The studies performed in support".?
Response: Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made. Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. The SDT added the phrase "or high side of the GSU voltages" to make Requirement R3, part 3.3.2 consistent with Requirement R4, part 4.3.2. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.4.1: The SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify Contingencies in adjacent systems that could impact the planners System. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. Data Retention: The SDT agrees with your suggestion. The wording in "data retention" for Requirement R3 has been changed. Measure M3 already uses the word "the". **Requirement R3, data retention:** The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.	
SERC Dynamics Review Subcommittee (DRS)	R3.3.1: We propose to add "permanently" before "disconnect".
Response: Part 3.3.1: The SDT believes that adding the word "permanently" has no significance for the steady state simulation of fault clearing. No change made.	
MAPP	R3.3.2 - We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose revised wording to qualify which generating units to consider and which voltage limits to simulate, "Trip generating units that are

Organization	Comments for Question 3
	connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. 3.3.3 We suggest that R3.3.3 be removed and this System Protection simulation requirement should be included in R3.3.1, which is the requirement to properly simulate Protection System actions Add R3.3.5 We suggest the addition of R3.3.5, Applicable System Operating Limits for the planning horizon shall not be exceeded. because Note “a” and “b” under “Steady State Only” at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, “shall”) and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note “a” should be revised and refer to R3.3.5.] Add R3.3.6 We suggest the addition of R3.3.6, ?The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements. because Note “d” under “Steady State Only” at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, “shall”) and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6.] R3.4.1: Remove the Transmission Planner and change “coordinate” to “provide” information to adjacent PC. We are working on other standards to remove “coordinate” and we should avoid it here. Coordinate requires interaction between two entities (or more), so if one does not respond, the other could be found to be non-compliant for something they cannot control.

Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made

Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.

Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded

The intent of Requirement R3, part 3.3.1 is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip unfaulted lines due to the post fault System loadings. Adding the suggested wording “including the simulation of transmission circuit loadability protection.” would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.”. Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.”. Header notes are part of Table 1 and therefore included in Requirement R3.

Part 3.4.1: SDT believes that it is necessary for the planner to coordinate with adjacent planners to identify contingencies in adjacent systems that could impact the

Organization	Comments for Question 3
planners system. Both the Transmission Planner and Planning Coordinator have this responsibility. No change made.	
NYISO	R3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed. R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities. If this remains, the NYISO requests that the phrase "evaluation of possible actions" be greatly clarified. R3.6 The NYISO seeks greater clarification of the phrase "consequential generation."
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.5: The SDT believes, and the majority of the industry agrees as seen in the comments, that continuing to study these possible scenarios is a valuable planning exercise. The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. No change made. Part 3.6: The term "consequential generation" is not used in Requirement R3, part 3.6. The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Xcel Energy	R3.3.3 Xcel does not believe that relay loadability limits is a valid system planning performance criterion because we are unsure how transmission relay loadability settings developed in accordance with PRC-023 can be more limiting than the Facility Ratings. Note that the purpose of PRC-023 standard is "Protective relay settings shall not limit transmission loadability" and it requires that the relay settings be higher than the "highest seasonal Facility Rating of a circuit". If relay settings limit the transmission loadability below its Facility Rating, then it is a violation of PRC-023. Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. R3.3 It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded The SDT agrees that relay loadability limits would exceed Facility ratings except in cases where exceptions to the loadability standard exist.	

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Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall:	
Sacramento Municipal Utility District	R3.3.3: To implement this requirement, the standard appears to call for one more facility rating which is based on Relay Loadability. Is the intent to also model the protection system actions if this limit is violated? Should such a requirement be moved to the MOD or FAC standard with conformance subject to Note (f) of Table 1 (Facility ratings shall not be exceeded) and R3.3.1 (simulate the removal of all elements that the Protection System and other " are expected to disconnect")?
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault System loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1.	
Puget Sound Energy, Inc.	R3.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the "neighboring" system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R3.4, the neighboring system may determine that a particular event is "less severe" and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.
Response: R3.4.1: The intent is for the Planning Coordinator/ Transmission Planner to include in their Contingency lists Contingencies from adjacent Systems which may impact their System, and to run these Contingencies. The Planning Coordinator/Transmission Planner is responsible for mitigation of performance deficiencies in their System caused by Contingencies on their list, including the Contingencies from adjacent Systems.	
Duke Energy	R3.5 includes the phrase "cascading outages". We believe that the word "cascading" should be the capitalized NERC-defined term "Cascading".
Response: R3.5: The SDT agrees. The phrase "cascading outages" has been changed to "Cascading" to align with the NERC Glossary of Terms. **Requirement R3, part 3.5**: Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be	

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available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Power Coordinating Council--RSC	Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 3.3.3: This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility's rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard, thereby introducing a double jeopardy issue. Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirements 3.5--This requirement needs clarification as to what is specifically required for the "evaluation of possible actions." The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving "evaluation" undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations. Requirement 3.5 NPCC strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together.Provide clarification as to what is specifically required for the "evaluation of possible actions". Requirement 3.6 Currently this requirement is not clear, and does not address any reliability issue. Clarification should be added that the "consequential generation" loss be excluded from the amount documented. Without the clarification, the Requirement should be deleted.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these "possible actions" are should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their System. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Midwest ISO	Requirement R3.6: With regards to the Generation Runback MW reporting; if no action is required then why require the entities

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	to provide this. Will it matter if 10MW or 100MW is part of the generation runback scheme tripped with the line? This is a system design issue which is not addressed by the standards, if this requirement is kept how is an entity expected to demonstrate compliance for this? This requirement is an administrative burden and we propose to remove R3.6 all together considering that there is not a reliability-related need for this information and it is unnecessary.
Response: Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES**.**	
Hydro-Québec TransEnergie (HQT)	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the “evaluation of possible actions.” Requirement 3.3.3 This requirement is already addressed in NERC Standard PRC-023 and reflected in the facility’s rating and should be removed from TPL-001-1 since the standard already requires observance of facility ratings. Requirement 3.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 3.1 to keep the related requirements together. Requirement 3.5 HQT, as does NPCC, strongly suggests making this a sub-bullet of Requirement 3.2 to keep the related requirements together. Requirement 3.6 ?Currently this requirement is not clear. HQT, as does NPCC, recommends clarification be added that the “consequential generation” loss is excluded from the amount documented.
Response: Part 3.5 The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that what these “possible actions” are should be left to the judgment of the Planning Coordinator/Transmission Planner whose has knowledge of their System. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Pacific Gas and Electric Co.	Requirements R3.4 and R3.5 appear to be related to and set the limits for R3.1 and R3.2 respectively. Suggest moving both Requirements R3.4 and R3.5 into R3.1 and R3.2, allowing these sub-Requirements (R3.4 and 3.5) to be deleted. It is unclear from the wording in R3.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R3.1 and R3.2. Please clarify the wording of R3.3.

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	For clarity we suggest that the wording in R3.3.3 be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits.
Response: Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded	
National Grid	Sub-Requirement 3.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 3.3.3: Relay Loadability is handled in greater detail (as it should be) under the proposed PRC-023 standard, so no reference should be made in this standard. It indicates a double jeopardy. Sub-Requirement 3.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.1 to keep the related requirements together. Sub-Requirement 3.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 3.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions." Sub-Requirement 3.6: This requirement does not address any reliability issue should be deleted. If it is to be kept, it is recommended that the "consequential generation" loss be excluded from the amount documented.
Response: Part 3.2: The SDT disagrees and believes there is value in running extreme event analysis to test the robustness of the System. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.4: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The SDT does not believe that combining the requirements provides any significant advantage. No change made. Part 3.5: The requirement is to evaluate possible actions which, if implemented, could reduce the likelihood or mitigate the consequences of an extreme event. The SDT believes that determining these "possible actions" should be left to the judgment of the Planning Coordinator/Transmission Planner who has knowledge of their	

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System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES**.**	
Tri-State Generation and Transmission Association	Thank you for removing the requirement to explain why "non-studied contingencies" would produce less severe results." Don't say "R3, part 3.4". Instead, for much easier referencing of sections, just say "R3.4". This applies throughout the entire Standard." R3.5 In the phrase "extreme events in Table 1 that are expected to produce more severe System impacts", the term "extreme events" seems redundant with "more severe". If Extreme Events were capitalized, it would be apparent that the TP should choose more severe events typified by details listed in the Extreme Events section of Table 1.
Response: R3, part 3.4: NERC has directed that the new terminology be adopted for all parts of a requirement. No changes made. R3.5: The SDT disagrees that the suggested changes add clarity. No change made. R3.5: The extreme events are listed in Table 1. Some of these events will have a greater impact than others on a given System. The SDT's expectation is that the planner knows his system and would use judgment to select the extreme events that would have a more severe impact on his System. No change made.	
Ameren	The readability of R3.3 could be improved with the following wording changes:3.3 Contingency analyses shall be performed: 3.3.1 To simulate the removal? 3.3.2 To simulate tripping generators where simulations show? 3.3.3 And results reviewed to ensure relay loadability limits? 3.3.4 To simulate the expected? Requirement R3.3.1 needs to include language regarding the automatic restoration of facilities. The following language is suggested: To simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention. Requirement R3.6: What is the purpose of this Requirement? We do not see how the reporting of this information adds to system reliability, and believe that this is more of a market issue. For those systems that are planned based on a single contingency, it is believed that numerous generation facilities would be impacted by the N-2 planning events and particularly those involving transmission facilities in the vicinity of power plant switchyards. Documenting manual or automatic generation runback or tripping of generation for the proposed P1 and P2 events is not unreasonable, but it is expected that developing runback or tripping schemes for the proposed P3-P7 events and reporting those contingencies and the amount of generation curtailed on an annual basis is of little value. Further, what information is to be reported for the P6 events for R3.6? As P6 events allow system adjustment following the first contingency (P1 event) to prepare for the second contingency (P1 event), is the runback information to be reported the generation that is to be curtailed after the first event (which should already be reported for the P1 category), after the second

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	event, or after both events? In real-time operations, security constrained economic redispatch continually adjusts generation to maintain transmission facility loadings within ratings anticipating the next single contingency event. Does the Standards Drafting Team intend for the industry to report the amount of curtailed generation in anticipation of the next P1 event?
Response: Part 3.3: The SDT has not adopted your suggested wording, but has made wording revisions to improve clarity as follows: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded. Part 3.3.1: The reference to “other automatic controls” is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	
Florida Power and Light	The requirement clearly states that "For the steady state portion of the Planning Assessment" it must perform simulations that show generator ride through voltage limitations under 3.3.2. However, ride through limitations are performed through stability simulations not steady state as required by R3. This is confusing as currently drafted, please provide clarity. Additionally, 3.2 requires studies to be performed to assess the impact of the extreme events. Yet, 3.3 requires analyses shall be performed but does not specify the events intended to study. Suggested language for 3.3 should say "Contingency analyses shall be performed to assess the impact of the extreme events and:" Under 3.3.1 it states that the Planner must simulate the removal of all elements that the Protection System would be expected to disconnect. Language should be included to allow the Planner to provide a rationale to assess more severe system conditions without needing to simulate the effects of Protection Systems. This would capture the intent of this requirement.
Response: Part 3.3.2: Generators can trip when bus voltage drops below minimum generator steady state voltage limits. The SDT believes that the voltage ride through test is applicable in post-contingency steady-state where the planner would know if post-Contingency bus voltage violates generator trip points. If a trip point is violated, Requirement R3, part 3.3.2 would require the planner to remove the generator in the post-Contingency case to assess if performance is met with the generator removed. No change made. Part 3.3: The SDT revised the wording of Requirement R3, part 3.3 as shown below to make it clear that it applies to both planning and extreme events: **Requirement R3, part 3.3**: Contingency analyses for Requirement R3, parts 3.1 & 3.2 shall: Part 3.3.1: Consistent with FERC Order 693, the intent of the SDT is for the planner to simulate the Protection System operation so that all elements that the Protection System is designed to remove (breaker to breaker) are removed in the simulation for the list of Contingencies the planner has developed in Requirement R3, parts 3.4 (planning events) and 3.5 (extreme events). The requirement does not preclude the Planning Coordinator/Transmission Planner from studying more severe scenarios. No change made.	

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NorthWestern Energy	The wording in R3.3.3 should be changed to "Ensure the power flows in the simulations are no higher than actual relay loadability limits. In R3.3.3 The term "loadability" needs to be defined. R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.3: Relay loadability is defined in NERC Standard PRC-023-1. R3.5: The SDT agrees that there could be an endless list of possible extreme events, The requirement has been written to allow the Planning Coordinator/Transmission Planner to use experience and the knowledge of their System to select relevant extreme events that have some reasonable probability of occurring. The SDT does not believe that combining Requirement R3, part 3.5 with Requirement R3, part 3.2 provides any significant advantage. No change made.	
American Transmission Company	We propose the following changes and questions: R3.3.1 The term of "controls" is ambiguous and not defined, unlike the term, "Protection Systems", which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. R3.3.1 Add the wording, ". . . including the simulation of transmission circuit loadability protection." to this requirement, rather than have a separate R3.3.3 requirement for recognizing overload protection. Overload protection is simply one of the types of automatic Protection System that may remove one or more elements from service. R3.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.2 must be different from its counterpart, R4.3.2, then please explain the reasons for any differences. R3.3.3 As noted above, we suggest that R3.3.3 be removed and that this System Protection loadability simulation requirement is included in R3.3.1 because overload protection is simply one type of automatic Protection System actions.

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	Add R3.3.5 We suggest the addition of R3.3.5 because any requirement in the head notes or foot notes of Table 1 should occur within the body of standard. The text of R3.3.5 should read, "Applicable System Operating Limits for the planning horizon shall not be exceeded." Presently, Note "a" and "b" under "Steady State Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note "a" should be revised and refer to R3.3.5.] Add R3.3.6 ? We suggest the addition of R3.3.6 because any requirement in the head notes or foot motes of Table 1 should occur within the body of standard. The text of R3.3.6 should read, "The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements." because Note "d" under "Steady State Only" at the beginning of Table 1 is stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.6 is added, Note "d" should be revised to refer to R3.3.6.] R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? R3.6 We suggest the wording of this requirement be revised to, "Manual or automatic generation runback or tripping is permitted to meet steady state performance requirements for planning events P1 through P7 in Table 1." because Reliability Standard PRC-015-1 already includes requirements regarding the review and approval of Special Protection Systems. Therefore, the Planning Assessment does not need to duplicate description of the design and intent of the Special Protection System.

Response: Part 3.3.1: The SDT believes that the meaning of "controls" is clear in the context it is used - "Protection Systems and Other automatic controls" (such as a cross-trip scheme) that disconnect elements to clear a fault". No change made.

Part 3.3.1: The intent of this requirement is to remove elements that the Protection System would remove to clear a fault (breaker-to-breaker). The Transmission circuit loadability protection could trip un-faulted lines due to the post fault system loadings. Adding the suggested wording "including the simulation of transmission circuit loadability protection." would change the intent of Requirement R3, part 3.1.1. No change made.

Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made.

The phrase "or high side of the GSU voltages" was added to Requirement R3, part 3.3.2 to make the wording in Requirement R3, part 3.3.2 the same as in Requirement R4, part 4.3.2.

Requirement R3, part 3.3.2: Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed

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minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded. The SDT believes this wording change should alleviate any perceived conflicts with the relay loadability standard. Combining Requirement R3, part 3.3.3 with Requirement R3, part 3.3.1 would change the intent of Requirement R3, part 3.3.1. **Requirement R3, part 3.3.3**: Trip Transmission elements when relay loadability limits are exceeded Part 3.3.5 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1.". Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.3.6 Proposed: The SDT believes that a new requirement is not needed. Requirement R3, part 3.1 states "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1." Header notes are part of Table 1 and therefore included in Requirement R3. Part 3.5: Requires the planning entity to identify which contingencies are chosen to be simulated in the study, and explain why these are chosen. The SDT assumes that the Planning Coordinator/Transmission Planner, applying experience of past studies and knowledge of its System, is in the best position to determine which Contingencies in Table 1 are most relevant, as it is impossible to study all Contingencies especially the multiple Contingency events. Requirement R3, part 3.5 requires "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts" if cascading outages - the trigger for evaluation of possible mitigating actions is cascading outages, not "overloads, under-voltages, voltage collapse, or loss of generator synchronization". No change made. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES. The SDT notes that generator runback or tripping is not prohibited by the standard.	
PJM	In R3.3.2, low voltage protection, like practically all generator protection, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.3.3 – Relay loadability should not be evaluated in a performance standard. A separate line rating and protection setting evaluation can determine if relay loadability is exceeded. If kept, this protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R3.5 – Needs a 3.5.1 similar to 3.4.1. R3.6 needs some words about sending up a red flag is the generation tripped or runback is greater than the largest single contingency. Like –The Reliability Coordinator, Transmission Operator and Balancing Authority must be notified if the planned generation tripped or runback scheme is greater than the largest single contingency.-
Response: Part 3.3.2: Where test data is not available, the SDT believes that most Transmission Planners/Planning Coordinators currently assume generators ride through low voltage based on extensive field experience. There is a project (Project 2007-09 — Generator Verification) that will provide the required generator data to validate the assumptions. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that the simulation models the generator response as it will react in the real world. If voltage ride through limits would cause a generator to trip in the real world, the study must determine if the performance requirements are met for the initiating event and subsequent generator trip. No change made. Part 3.3.3: The SDT changed the wording to further clarify the action required when relay loadability limits are exceeded.	

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Requirement R3, part 3.3.3: Trip Transmission elements when relay loadability limits are exceeded Part 3.5.1 Proposed: The SDT has not included a requirement on the Planning Coordinator/ Transmission Planner to coordinate with adjacent Systems to identify extreme Contingencies in these adjacent Systems that would impact the Planning Coordinator/Transmission Planner's System. Part 3.6: The SDT has deleted Requirement R3, part 3.6 in response to industry comments as it is not a performance oriented requirement affecting the reliability of the BES.	

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters expressed concerns that the new "relaying" requirements that were added to draft 4 would essentially require modeling every zone 3 relay in each Interconnection. The requirements do not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then one can either take action according to the generic model results or investigate the characteristics of the relays actually used on that branch.

In response to several commenters, Part 4.1.2 was modified to no longer require tripping of out-of-step generators in the simulations.

Clarifications to the requirements were made as follows:

Requirement R3, part 3.3.2 - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall :

Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Organization	Comments for Question 4
Independent Electricity System Operator	(1) Part 4.3: Similar comments on Part 3.3 provided under Q3 also apply here. (2) Parts 4.4 and 4.5: similar comments on Parts 3.4 and 3.5 provided under Q3 also apply here.(3) We do not have any comments on the measure, VRF, Time Horizon and VSLs.
SRC of ISO/RTO	1. Part 4.3: Similar comments as for Part 3.3 (i.e. overly prescriptive, etc...) provided under question 3 also apply here. 2. Parts 4.4 and 4.5: Similar comments on Part 3.4 and 3.5 provided under question 3 also apply here.

Organization	Comments for Question 4
	AESO does not comment on VSLs or VRFs.
Response: See response to your comments on Requirement R3, part 3.3. See response to your comments on Requirement R3, parts 3.4 and 3.5.	
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall perform?. "* Similar to comments provided in R3, Section 4.1 and 4.4 appear to be related. Confusing references can be eliminated by combining them and removing 4.4: "4.1. Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified and studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1. A list of those Contingencies and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "* Similarly, Section 4.2 and 4.5 appear to be related. Confusing references can be eliminated by combining them and removing 4.5: "4.2. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and studies shall be performed to assess the impact of the extreme events. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. A list of those events and the rationale for those Contingencies selected for evaluation shall be available as supporting information. "
Response: The agreements required by Requirement R7 are intended to clarify the responsibilities among the Planning Coordinator and Transmission Planners. The SDT believes this is clear in the existing language. Requirement R4, parts 4.1 & 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Requirement R4, parts 4.2 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Northeast Utilities	[R4.1.1] This requirement needs better clarification. Does it mean that a generator that trips on any other condition apart from tripping on out-of-synchronism is acceptable? Example if the generator is not able to ride through a low voltage condition created by a fault. We recommend that this requirement is dropped from TPL-001-1 standard. [R4.1.2] This approach will require a different modeling technique from current practice and will require an implementation period. [R4.3.2] Refer to comment for Requirement R3.3.2. [R4.5] This requirement needs clarification as to what is specifically required for the "evaluation of possible actions". Otherwise the following is recommended:" It should be clear that an evaluation does not require solution development for all Extreme Events" Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered."

Organization	Comments for Question 4
Response: Part 4.1.1: The requirement will not be dropped. The requirement states that for event P1, no generating unit shall pull out of synchronism. If the event results in a unit tripping due to fault clearing action or due to an SPS action, this is acceptable. Low voltage ride-through is handled in a separate requirement (Requirement R4, part 4.3.2). Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.3.2: See response to your comment on Requirement R3, part 3.3.2. Part 4.5: The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be. No change made.	
Central Maine Power Company	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
ISO New England	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
United Illuminating	4.1.1 This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation

Organization	Comments for Question 4
	period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. 4.1.2 This will require implementation period. 4.2 Item 4.2 should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. 4.4 It is suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. The SDT believes that generators smaller than 20 MW also need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Florida Municipal Power Agency, and its Member Cities	4.1.1, suggest rewording "(a) generator being disconnected from the Bulk Electric System ", system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially require modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT? If so, FMPA suggests limiting these bullets to Facilities 230 kV and higher.
Response: Part 4.1.1: The standard applies only to the BES and therefore, without revision, does not place this requirement on generators not directly connected to the BES. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. No change made.	

<table>
<tr><th>Organization</th><th>Comments for Question 4</th></tr>
<tr><td>Xcel Energy</td><td>4.3 Does the requirement allow it to be optional as to whether an entity chooses to include generator exciter controls, PSS, etc.? To what degree must a device impact the study area, in order for it to be required to be included in the simulation?

Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted.

R4.3 It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3.

R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If it is the intent to require that entities assess both, we suggest including the assessment in the list of sensitivities.</td></tr>
<tr><td colspan="2">Response: Part 4.3: If generator exciter controls and PSS do not affect the study area, it is not necessary to model them. However, most Transmission Planners will have them in their simulations because these controls are already included in their model. It is up to your judgment as to what control devices have an impact on the study area.

Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.

Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.</td></tr>
<tr><td>FirstEnergy Corp</td><td>A. The SDT should bring consistency to the text used for sub-part 4.3.2 of R4 and sub-part 3.3.2 of R3. In R4 it indicates "generator bus voltages or high-side of GSU" as the reference voltage point whereas 3.3.2 only indicates "generator bus voltage" as the point of reference. If the generator bus is modeled at the generator voltage, then this should be the reference voltage point. If the generator is modeled directly connected to the BES (no transformer is explicitly modeled), then the transmission voltage should be the reference voltage.

B. Requirement R4, sub-part 4.3.2 is well intentioned, but problematic for those performing dynamic simulations. Does a Guide or Practice exist to determine the dynamic undervoltage capability of a synchronous machine? Most excitation systems contain "field forcing" functions to maintain stability through fault conditions (1 second or so of capability), but FE is not aware of any published, readily available quantities or formulas that can be used to determine this highly time dependent function. Application of the steady state minimum voltage is grossly over-conservative. FE questions why low voltage limits should even be considered in dynamic simulations, since the primary concern for generating equipment during events of this nature and duration are metallurgical, not thermal (voltage).

C. Requirement R3 sub-part 4.3.3 is troublesome since the modeling detail needed for Protection Systems within traditional stability programs is not available. It is expected that software adjustments will be needed from the software vendors before this</td></tr>
</table>

Organization	Comments for Question 4
	requirement can be met. The implementation plan of 24 months may be insufficient in regards to 4.3.3. In draft 3 Progress Energy and Ameren in the Q11 comments indicated that more time is needed for Protection System modeling required by TPL-001-1. The SDT responded "The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards." The inclusion of sub-part 4.3.3 in Draft 4 does not appear to align with this response. Please clarify the intent of 4.3.3 and respond regarding FE's belief that more time is needed for software improvements. D. We suggest the team discontinue the use of "Coordinate with adjacent transmission planners" in regards to sub-part 4.4.1 related to the inclusion of contingencies from adjacent systems. The "coordination" type of requirements creates a need to develop compliance evidence such as e-mail correspondence, meeting minutes etc that serve no real reliability purpose. The requirement should simply be that the TP shall include adjacent contingencies expected to produce the more severe System impacts on their systems. In fact, sub-part 4.4 already includes that language. We suggest the team append the sentence "The planning event contingencies shall include:" to the end of sub-part 4.4 followed by two bullets that indicate 1) events within the TP's system and 2) events on adjacent transmission Systems.
Response: A. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2 -** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. B. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. No change made. C. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe that more time is needed in the Implementation Plan. No change made. D. Part 4.4.1: The SDT strongly disagrees with your suggestion. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. No change made.	
Gainesville Regional Utilities	As generation and transmission elements are added to our small system, we evaluate the stability impact as part of its feasibility and impact studies. After installation and in each year of a critical conditions study at the regional level, our elements are considered in the regional priority listings to determine if any stability issues need additional or continuous evaluation. Again, as a "part of the whole" our elements are considered and our assessment is based on these and other findings. Again, this revision

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<tr><td></td><td>seems to add clarity to this requirement and its parts. Good Job!</td></tr>
<tr><td colspan="2">Response: Thanks for your comment.</td></tr>
<tr><td>Progress Energy Florida, Inc.</td><td>As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.</td></tr>
<tr><td colspan="2">Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.</td></tr>
<tr><td>CenterPoint Energy</td><td>CenterPoint Energy recommends deleting part 4.4.1 as being overly prescriptive and difficult to demonstrate in an audit.</td></tr>
<tr><td colspan="2">Response: Part 4.4.1: The SDT disagrees that this requirement is prescriptive and difficult to demonstrate compliance. There is a need to consider Contingencies on a neighbor's System which may impact your System. It is much easier to coordinate with adjacent Transmission Planners for Stability simulations than to study them all yourself. A requirement to study Contingencies on adjacent Systems creates an enormous burden for Stability simulations which have to take into account substation configurations and relaying times. A much better method is to coordinate with neighbors as to which Contingencies on their System could impact your System and then study only those Contingencies on the neighbor's System. For the audit you should show documentation where you asked and received these Contingencies from your neighbors. No change made.</td></tr>
<tr><td>Deseret Power</td><td>Comments: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted.

It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3.

R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.</td></tr>
<tr><td colspan="2">Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.

Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.</td></tr>
<tr><td>ITC Holdings</td><td>Comments:On R4.3.2:Assumptions regarding Low Voltage Ride Through (LVRT) capability are risky and not well understood. If the SDT feels this is a critical requirement that merits corrective action then we believe LVRT characteristics for various machine types should be developed through a NERC process. Without such “standards”, it will be difficult to justify CAPs based on LVRT</td></tr>
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Organization	Comments for Question 4
	assumptions. For example, would the Transmission Owner (TO) or Generator Owner be responsible for the cost of VAR CAPs if an LVRT assumption were violated. Can a TO require an LSE to install automatic load shedding for an LVRT assumption when cascade or local load loss result from an LVRT assumption? In addition, as the SDT has already indicated, the industry is still in a learning curve regarding the dynamic behavior of certain loads. If LVRT capability is considered as a critical requirement, then what about High Voltage Ride Through (HVRT) capability? The violation of HVRT could also cause certain damages to the system. R4.4.1 - (contingency list coordination with neighbors) It's unclear as to the "measure" for this requirement. Do you give your neighbor a list of "contingencies" in your area. Should it include all categories (p1 thru p7 for example)? Does your neighbor have to study a cascade situation in his system caused by an outage in your system? Are joint studies merited? More importantly, if an outage in a neighboring system requires a CAP, who's responsible, particularly if the CAP involves the neighboring system. Does the neighbor have to have a CAP, according to this standard, if the violation is in your system, and the CAP is in his? Who pays? Are you putting a study burden on your neighbor when you do this? Do you include additional contingencies to ensure that you do not miss a contingency that might impact your neighbors system to avoid any potential compliance implication on you?
Response: Part 4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. And yes, you can make System improvements based on reasonable assumptions. The SDT does not believe that high voltage ride through of generators has been an issue in past events like low voltage ride through has been. Thus, there is no need to include it in the standard. Part 4.4.1: The intent of the requirement is to give your neighbor a list of Contingencies (P1-P7) for which you have observed an impact to the neighbor's System. Your neighbor will then study those Contingencies. Joint studies are not required. If a Contingency on a neighbor's System causes a problem on your System, you must find a solution and the reverse situation is the same.	
TVA System Planning	For R4.1.2. Suggested change: For planning events P2 through P7: A generator that pulls out of synchronism shall be considered in the simulations and the resulting apparent impedance swings shall not result in the tripping of any Transmission System elements other than the generating unit and its directly connected Facilities." [Since often tripping a out of step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. 4.3.3. Suggested change: Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers when such devices impact the study area. Without this change, a significant amount of effort would be required (with no added benefit) to evaluate protection systems all over the grid that have little or no impact on the study area.

Organization	Comments for Question 4
	R4.3.1: add "if reclosing is actually used as part of a protection system" to the end of the sentence.
Response: Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays all over the grid. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made.	
SERC Dynamics Review Subcommittee (DRS)	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that all transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? For R4.1.2. Suggested change: Replace word "tripped" with "considered". Reasoning: Since often tripping an out-of-step generator reduces impedance swings, if the simulation shows acceptable impedance swings and voltage levels without tripping the generator, why would we be required to determine the tripping time and simulate tripping in each of the simulations that we have to run for these event categories? Without the suggested change involving the word "considered", significant extra effort would be required to perform simulations for small generators with no added benefit in achieving the purpose of assuring that impedance swings from generators are not passing through lines on the Bulk Electric System for events P2-P7. Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence. Part 4.4: place a space between words "Table 1" and "that".
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	

Organization	Comments for Question 4
Part 4.4: The typo has been corrected.	
SERC Planning Standards Subcommittee	It is not clear as to the expectations of standard drafting team for dynamic modeling of relays. Parts 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent, please clarify? Part 4.3.1: add "when used as part of a protection system" to the end of the sentence. Part 4.3.3: add "when such devices affect the study area" to the end of the sentence.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made.	
Ameren	It is not clear as to the expectations of the standard drafting team for dynamic modeling of relays. Requirements 4.1.2 and 4.3.3 imply that transmission relays may need to be explicitly modeled in the dynamic simulations. Is this the team's intent? If so, has the team given consideration to the availability of relay models in the commonly used Power System simulation software programs, and considered the cost and effort required for such implementation versus the expected benefits? Is there any historical experience that would imply that such modeling is crucial to the reliability of the BES? It is suggested that generators that pull out of synchronism be given consideration for their effects on the system, without requiring simulation of generator tripping in R4.1.2. Requirement R4.3.1 needs to include some additional language regarding the automatic restoration of facilities and allowance of high-speed reclosing. The following language is suggested: Simulate the removal of all elements that the Protection System is expected to disconnect and the restoration of all elements that the automatic controls are expected to restore for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high-speed reclosing, if high-speed reclosing is employed. R4.3.3: Suggested wording addition: "for those devices relevant to the study area." A space needs to be added between "Table 1" and "that" in Requirement 4.4.
Response: Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.1.2: The SDT agrees with the concern and has modified 4.1.2.	

Organization	Comments for Question 4
Requirement R4, part 4.1.2 - For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.1: The SDT does not see the need for the standard to specify other automatic controls. No change made. Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to the study area. No change made. Part 4.4: The typo has been corrected.	
Utility System Efficiencies, Inc. (USE)	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Response: Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3 -** Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican urges that the SDT delete 4.1.1 which requires that no generating unit shall pull out of synchronism during a stability analysis. A generating unit pulling out of synchronism does not necessarily result in thermal, voltage, or stability violations and does not necessarily result in cascading, instability, or uncontrolled separation. The loss of synchronism and tripping of a generator is in effect no different than tripping due to mechanical issues such as tube leaks. Present electric grid design that allows tripping for out-of-synchronism is reliable and secure. Adding the requirement that no unit may pull out of synchronism goes well beyond current grid design practices. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican also made this comment under Question 11.)? 4.3.1 indicates that for stability contingency analysis shall be performed to “Simulate the removal of all elements that the

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	Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention while also considering the impact of successful or unsuccessful high speed reclosing.” MidAmerican believes that it is over-kill to provide this as a general requirement as written. In such a case, such successful or unsuccessful high speed reclosing analysis conceivably would need to be performed for numerous unnecessary situations given the generally wide spread use of high speed reclosing on transmissions systems. MidAmerican urges the SDT to revise this requirement to only require the study of successful and unsuccessful high speed reclosing where high speed reclosing has been added to resolve a specific stability issue such as a breaker closing angle issue.” 4.5 MidAmerican believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. MidAmerican recommends that 4.5 be revised to indicate that a list of those events that “produce more severe System impacts AND ARE MORE LIKELY” (the words in all caps are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation. MidAmerican recommends the data retention for R4 and M4 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support”. The word in all caps is a word suggested to be added.

Response: Part 4.1.1: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. No change made.

Parts 4.1.2 & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.

Part 4.3.3: As stated above, a generic relay model can be used to meet this requirement. Therefore, the SDT does not see a need to add words that specifically limit the simulation of these impacts to only high voltage lines. No change made.

Part 4.3.3: Because this requirement does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan. No change made.

Part 4.3.1: The SDT disagrees. The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. If you are using it, then it should be covered in the studies. No change made.

Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the Planning Events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.

The SDT agrees and has made the suggested change.

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TIS	Nowhere in the stability requirements is it necessary for evaluating the loss of all generators in a station; it is included in the steady state requirements. The standard should require examination of all units in a generating station where single line-to-ground faults on generation station buses could cause the clearing of the entire station. Further, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability analysis for loss of all generators at a station these are things that happen!
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme events. Single phase faults with stuck breaker are included in planning event P4.	
Southern Company	Part 4.3.1: add “when used on the system” to the end of the sentence. This is needed to clarify that you don't have to study high speed reclosing if you don't utilize it.
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made**.**	
Oklahoma Gas & Electric	R4 OG&E believes the Transmission Coordinator be held accountable for R4. The Transmission Coordinator should coordinate this type of study with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work. R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. OG&E does not like being held accountable to nebulas standards. Need more specific information.
Response: R4: The SDT assumes you meant to say Planning Coordinator rather than Transmission Coordinator (which is not in the Functional Model). Requirement R7 requires the Planning Coordinator and Transmission Planner to work out who will be conducting what studies. Parts 4.4 & 4.5: Use your engineering judgment to determine which Contingencies could produce more severe results. For example, it could be argued that faults close in to generating plants would be more severe than faults two busses away from the plant.	
MAPP	R4.1.1 & R4.1.2 - We propose that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations. R4.3.2 We suggest that this requirement be removed because it is premature to require Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement we propose wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards

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	requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. Add R4.3.5 We suggest the addition of R4.3.5, "Applicable System Operating Limits for the planning horizon shall not be exceeded." because Note "a" and "b" under "Stability Only" at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, "shall") and all Requirements should be explicitly stated under Requirements and not be introduced (and hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note "a" should revised and refer to R4.3.5.]
Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table. No change made.	
NERC Standards Review Subcommittee	R4.1.1 & R4.1.2 The MRO NSRS proposes that these sub-requirements be removed. The generating unit loss of synchronism does not necessary result in a thermal, voltage, or stability violations.R4.1.1 - Wording from R4.1.1 about no generating unit pulling out of synchronism should be deleted. The simple loss of synchronism of a unit or even multiple units does not necessarily result in thermal, voltage, or stability. All standards and requirements should demonstrate a reliability related basis. There is no direct reliability or security requirement that prevents a unit from loosing synchronism. The loss of a unit from synchronism is no different than the regular loss of the unit for mechanical reasons, therefore this requirement unnecessarily results in FERC directing utilities to build infrastructure beyond what is needed for system security. R4.1.3 The MRO NSRS proposes that this sub-requirement be removed because there are no NERC power system damping standards. R.4.3.2 The MRO NSRS suggests that this requirement be removed because it is premature to requirement Transmission Planners to simulate under voltage tripping until the MOD standards require it. If the drafting team does not remove this requirement the MRO NSRS proposes wording like, "Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment". The requirement should not apply to all relevant

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	generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the Transmission Planner and Planning Coordinator. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. As written R4.3.3, it might be interpreted to require responsible entities to add the modeling of all relaying instead of just pertinent. Perhaps, R4.3.3 should be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, the MRO NSRS proposes that the implementation time for R4 to be increased. The MRO NSRS believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. The MRO NSRS urges that the SDT increase the implementation time for R4 from 2 years to 4 years. When it may actually respond or triggered. R 4.3.1 This requirement refers to high speed reclosing and the MRO NSRS presumes that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. The MRO NSRS recommends that the term high speed reclosing be defined for this sub-requirement with an angular stability component. R4.5 - The MRO NSRS believes that the extreme events that should be studied are the more credible ones. The credible events are those that the planner considers credible when considering both how severe the event is and how likely it is. For example, while a tornado might be the most severe event, its likelihood of hitting key facilities is quite low. It is more likely to have a severe thunderstorm that hits key facilities but causes less impact on the system. The planner should plan for the severe thunderstorm but perhaps should not plan for the tornado. The MRO NSRS recommends that 4.5 be revised to indicate that a list of those events that "produce more severe System impacts and are more likely" (the bolded words are suggested words to be added) be studied as being more credible events. Then the purpose of the last sentence in 4.5 is clearer in that possible actions that reduce the likelihood or mitigate the consequences of the events shall be reviewed for those contingencies where likelihood in combination with consequences justify such evaluation.

Response: Parts 4.1.1 & 4.1.2: The SDT disagrees. A unit's pulling out of synchronism for a normally cleared fault is an indication of a weak Transmission System or insufficient relaying. A corrective action should be developed. The SDT sees no reason to delete Requirement R4, parts 4.1.1 and 4.1.2.

Part 4.1.3: Requirement R4, part 4.1.3 requires the Planning Coordinator and Transmission Planner to use their engineering judgment on what constitutes acceptable damping. The SDT did not think it appropriate to prescribe what acceptable damping is. Most Planning Coordinator's and Transmission Planner's should already have this kind of criteria for their systems. No change made.

Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed

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wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2., Requirement R3, art 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2 -** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Therefore, the SDT does not believe this should be limited to only high voltage lines. Because this requirement does not necessarily require modeling of specific relays, the SDT also does not agree that a longer time is needed in the Implementation Plan. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.5: The extreme events for Stability analysis cover Contingencies like 3-phase fault with stuck breaker or a 3-phase fault after an element has gone out of service prior to System adjustments. These events are less likely to occur than the planning events. The SDT does not see any need to add the suggested qualifier "are more likely" because by definition none of the extreme events are more likely.	
Sacramento Municipal Utility District	R4.1.1: There appears to be a conflict between what is not allowed for a generator in R4.1.1 and what is allowed in Note (b) of Table 1 (consequential generation loss “ which is an undefined term “ and hence can be interpreted as one sees fit). R4.3.3: It is unclear what is expected from this requirement. Are Protection personnel to take the results of the transient stability simulation and determine its impact on the Protection System? Or, is it that the Protection System should be properly modeled in stability simulations? If it is the latter, this requirement is already covered by R4.3.1 (simulate the removal of all elements). R4.3.2: If done right, this requirement should be already complied with under R4.3.1. If it needs to be spelled out, a better place may be in the MOD Standards. R4.4 and R4.5: Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3.R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both, we suggest including the assessment in the list of sensitivities.
Response: Part 4.1.1: The generation loss referred to in note b is the generation that is disconnected from the System by fault clearing action. This is completely different from a generator pulling out of synchronism. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic	

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simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.2: Requirement R4, part 4.3.1 requires simulating the removal of elements which must be removed to clear the fault. Requirement R4, part 4.3.2 involves generator low voltage ride-through and tripping the generator when voltages are too low. These are two completely different things. Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3 -** Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it.	
Manitoba Hydro	R4.1.2: For P2 events, a generator that pulls out of synchronism must be tripped. Tripping of the generator could result in Interruption of Firm Transmission Service unless redispatch is allowed - Footnote 9 should be allowed. R4.1.3 states that “power oscillation shall exhibit acceptable damping as established by the PC and TP”. There is no requirement for the PC or TP to develop criteria for acceptable damping. Requirement R5 or R6 should be expanded to require the PC and TP to establish criteria for acceptable power oscillation damping. R4.2: Recommend changing “the list” to “the Contingency list” to add clarity and consistency.
Response: The SDT agrees and has changed Table 1 so that footnote 9 applies to planning event P2. Part 4.1.3: There doesn't have to be a specific requirement for the Planning Coordinator and Transmission Planner to establish damping criteria. Most should already have such a criteria. No change made. Part R4.2: The SDT does not see any value in adding the word "Contingency" to the word "list". No change made.	
Duke Energy	R4.3.3 must be clarified regarding what method is to be used for assessing the impact of transient swings on Protection System operation. For example, how is this to be included in models, is this referring to a post simulation evaluation comparing results to actual relay settings, etc?? R4.5 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined term “Cascading”.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.5: The SDT has modified Requirement R4, part 4.5 to use the term "Cascading" rather than "cascading outages."	

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Requirement R4, part 4.5 - Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
NorthWestern Energy	R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. We suggest moving both R4.4 and R4.5 into R4.1 and R4.2, then R4.4 and R4.5 could be deleted. R4.3 is unclear whether the Contingency analyses need to be performed for all planning events or only the more severe events referenced in R4.1 and R4.2. R4.3 needs clarification. R4.3.1 requires considering the impact of both successful and unsuccessful high-speed reclosing. Since successful reclosing is a much less severe event, it seems unnecessary to assess both. If entities need to assess both, the assessment could be in the list of sensitivities. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified. **Requirement R4, part 4.3 -** Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall : Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. Part 4.5: Requirement R4, Part 4.5 refers to the Contingency events listed in the extreme event Stability section of Table 1. Your example does not fall into the events listed. For this analysis you don't just keep adding more and more outaged elements. You only have to do the ones listed in the Table that would be expected to produce more severe results.	
Northeast Power Coordinating Council--RSC	Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require

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	an implementation period. Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Requirement 4.4 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 NPCC strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together. This requirement needs clarification as to what is specifically required for the “evaluation of possible actions.” The list associated with Requirement 2. part 2.7.1 provides examples of possible actions, and leaving “evaluation” undefined offers the Planning Coordinator and Transmission Planner the leeway to use judgment in making their evaluations.
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region.. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. The requirement is to evaluate possible actions which could reduce the likelihood or mitigate the consequences of the event. The standard should not prescribe those actions. It is up to your judgment what those possible actions could be.	
Midwest ISO	Requirement R4.3.1: Please consider adding the following language to the end of the sentence “when used as part of a protection system”. Requirement R4.3.1: Please consider adding the following language to the end of the sentence “when such devices affect the study area”.
Response: Part 4.3.1: The requirement is to consider the impact of high speed reclosing. This does not mean that you need to study high speed reclosing if you are not using it. No change made. Part 4.3.1: High speed reclosing would be considered only for the line you are studying. Therefore, it always impacts the study area. No change made.	
Hydro-Québec TransEnergie	Requirements 3.5 and 4.5 Both of these requirements need clarification as to what is specifically required for the “evaluation of

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(HQT)	possible actions." Requirement 4.4 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.1 to keep the related requirements together. Requirement 4.5 HQT, as does NPCC, strongly suggests making this requirement a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the System pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the System in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
Bonneville Power Administration	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Idaho Power	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Modesto Irrigation District Transmission Planning	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more

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	severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
NV Energy	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Pacific Gas and Electric Co.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Puget Sound Energy, Inc.	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.41 requires clarification. With respect to these "Contingencies on adjacent systems," the responsibility of listing and analyzing these events needs to be clarified. Should the event simulation be the responsibility of the "neighboring" system (where the event would occur) or the adjacent system that may feel the impact of this event? Per the developed rationale from R4.4, the neighboring system may determine that a particular event is "less severe" and hence not studied, even though this event may potentially impact a neighbor. Further, for these "Contingencies on adjacent systems" that result in system performance outside one's own operating limits, it is unclear who is responsible for mitigating these contingencies. It is potentially awkward in that one entity may be planning another entity's system improvements.
San Diego Gas & Electric Co	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted.

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	It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Southern California Edison (SCE)	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. t is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
SRP	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2 respectively. Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both. If the intent is to make entities assess both we suggest including the assessment in the list of sensitivities.
Western Area Power Adm - RMR	Requirements R4.4 and R4.5 appear to be related to and set the limits for R4.1 and R4.2, respectively. I Suggest moving both Requirements R4.4 and R4.5 into R4.1 and R4.2, allowing these sub-Requirements (R4.4 and 4.5) to be deleted. It is unclear from the wording in R4.3 whether the Contingency analyses need to be performed for all planning events or the more severe events referenced in R4.1 and R4.2. Please clarify the wording of R4.3. R4.3.1 appears to require an assessment of both successful and unsuccessful high-speed reclosing. Successful reclosing is a much less severe event, so it seems unnecessary to assess both.

Response: Parts 4.4 & 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.

Part 4.3: The Contingency analyses in Requirement R4, part 4.3 refer to the studies in Requirement R4, parts 4.1 and 4.2. However, for additional clarity, Requirement R4, part 4.3 has been modified.

Requirement R4, part 4.3 - Contingency analyses for Requirement R4, parts 4.1 and 4.2 shall :

Part 4.3.1: The Standard requires you to study only the events which produce more severe System impacts. If two Systems are swinging apart, then successful high

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speed reclosing could show a more severe impact. However, if successful reclosing is not expected to produce a more severe impact, you are not required to study it. No change made.	
National Grid	Sub-Requirement 4.1.1: This should be revised to only be applicable to generators interconnected to the BES. This may need an implementation period as not all existing units are interconnected in accordance with the standard as proposed. As written this applies to small generators and doesn't necessarily reflect reliability of the network. 20 MW is a recommended generator minimum size. Sub-Requirement 4.1.2: Simulating the tripping of a generator that pulls out of synchronism is presently not modeled and will require implementation period. Sub-Requirement 4.2: This requirement should be deleted. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. Therefore Extreme Event analysis no longer provides any value in this standard. Sub-Requirement 4.4: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. Sub-Requirement 4.5: It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together. Provide clarification as to what is specifically required for the "evaluation of possible actions."
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any).	
Tri-State Generation and	The standard needs to use the term "Dynamic Stability", not just "Stability", to differentiate between dynamic and voltage stability

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Transmission Association	considerations. R4.1 contains the phrase “based on the Contingency list created in Requirement R4.4”. The contingency list is referred to in R4.4 (and R3.4), but is not created there. In R4.3.1 the requirement for additional evaluation of “successful or unsuccessful high speed reclosing” is an additional performance requirement. Whether this refers to the possibility of reclosing mechanism failure, or the effectiveness of reclosing operations (there is some ambiguity here). The reference to high speed reclosing in R4.3.1 is a good addition. For ease in auditing, it should be listed as a separate requirement (or sub-requirement).
Response: The SDT does not see any need to use that term as it does not provide any needed clarity. No change made. Parts 4.1 & 4.4: The Contingency list is created in Requirement R4, part 4.4. The SDT does not understand your comment. Part 4.3.1: The SDT does not see any value in making this a separate requirement. No change made.	
American Transmission Company	We propose the following changes and pose the following questions: R4.1.1 We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. R4.1.2 We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 4.3.1 This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be defined for this sub-requirement.R. 4.3.2 We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. R4.3.3 Every dynamic event simulation involves power system transient swings. What are the size and scope of the transient swings and what is the scope of the system to be examined, to which this requirement is referring? Please reword this requirement to give the industry a better understanding of what is intended. Add R4.3.5 We suggest the addition of R4.3.5, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” Note “a” and “b” under “Stability Only” at the beginning of Table 1 are stated in the form of a Requirement (e.g. uses the verb, “shall”) and all Requirements should be explicitly stated under Requirements and not be introduced (and basically

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	hidden) in the performance notes of Table 1. [After R4.3.5 is added, Note “a” should be revised and refer to R4.3.5.] Add R4.3.5 We suggest the addition of R4.3.5, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” because Note “a” and “b” under “Steady State Only” at the beginning of Table 1 is stated in the form of a Requirement (e.g. note usage of the verb, “shall”) and all Requirements should be clearly included in the body of the standard and not be introduced (and basically hidden) in the performance notes of Table 1. [After R3.3.5 is added, Note “a” should allude to R3.3.5.]
Response: Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Part 4.1.2: The standard applies only to the BES as defined by your region. No change made. Part 4.3.1: The SDT believes that there is general understanding in the industry that reclosing that is accomplished in a number of seconds is not high speed reclosing. It is just known as reclosing. High speed reclosing would occur within a second after fault clearing. Part 4.3.2: The purpose of Requirement R4, part 4.3.2 is to take into account the low voltage ride-through capability of generators in the studies. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. Your proposed wording is not significantly different from the existing wording. No change made. Part 4.3.2: To be consistent with Requirement R4, part 4.3.2, Requirement R3, part 3.3.2 has been modified to also allow the use of voltages on the high side of the GSU. The use of voltages on the high side of the GSU allows greater flexibility in applying voltage ride-through capability of generators - some of which are defined on the high side of the GSU. **Requirement R3, part 3.3.2** - Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. Part 4.3.5: The SDT does not see a need for making these header notes into requirements. These apply more directly as qualifiers for the results of the simulations and therefore, they fit better as header notes to the Table.	
American Electric Power	We recommend inserting "unstable" in the requirement language as follows: "Simulate the impact of unstable transient swings on Protection System operation?" Our perception is that the wording of 4.3.3 is almost certain to require the representation of impedance relay characteristics on both ends of all lines in a study area in order to satisfy an audit, and would eventually require representation on both ends of all BES lines as all areas would be studied at some point. This sub-requirement would place a huge burden on transmission planning and protection engineering staff. Experience has shown that tripping of transmission lines or transformers on stable swings is extremely rare. The burden this sub-requirement would cause as presently worded is not commensurate with the expected benefit.
Response: Part 4.3.3: The requirement is to take into account the impact of transient swings. This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a	

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branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT does not agree to insert the word "unstable" before "transient swings" because some stable swings can get into relay characteristics.	
FRCC Transmission Working Group	With regard to the Moderate VSL, consider deleting “utilizing data” in order to avoid penalizing twice for failing to meet R1. 4.1.1, suggest rewording “(a) generator being disconnected from the Bulk Electric System “, system as defined in the Glossary includes distribution, and we do not believe that is the intent of the SDT. 4.1.2, 4.3.1 and 4.3.3 essentially requirerequires modeling every Zone 3 (or higher, such as Zone 5) relay in each Interconnection (or at least in the Region under study and adjacent regions) because, in order to simulate the impact of a power swing on a distance relay, one would need to know the characteristics of the distance relay and how long the transient swing remains within that characteristic, which means modeling the relay. Is that the intent of the SDT?
Response: Requirement R1 requires you to maintain System models. Requirement R4 requires you to use that model data for your Stability studies. These are two different things requiring two VSLs. No change made. Part 4.1.1: The standard applies only to the BES as defined by your Region. No change made. Parts 4.1.2, 4.3.1, & 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line.	
E.ON U.S.	With respect to Category P6, a Multiple Contingency event (the overlapping occurrence of two or more single events) allows Non-Consequential Load Loss. The "System adjustments" do not list yet do not exclude Load Shedding. E.ON U.S believes that Load Shedding should be included as an option in similar manner to Curtailment of Firm Transmission Service. If the SDT disagrees with this recommendation, then E.ON U.S. suggests that the SDT clearly state the allowed use of Load Shedding. E.ON U.S. observes that in the case of Extreme Events the SDT provided the following response to a previous comment:Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.E.ON U.S. recommends that the word "station" in event 2d to be changed "plant".
Response: In Event P6 the term System adjustments has a reference to footnote 9. This footnote clearly states that System adjustments do not include the shedding of firm Demand. The allowable loss of Non-Consequential Load for event P6 refers to after the second Contingency has occurred. The SDT agrees that there needs to be consistency and has changed the word "plants" to "stations" in extreme event 3a.	
Oncor Electric Delivery	Within “stability requirements” there is no requirement for evaluating the loss of all generators in a station; it is included in the steady state requirements. We recommend that the standard require examination of all units in a generating station where single line-to-ground faults on generation station buses could result in clearing of the entire station. Furthermore, single phase faults with delayed clearing (or stuck breaker) are not included. Often, such exclusion of stability

Organization	Comments for Question 4
	analysis for loss of all generators at a station these are things that happen! 4.1.1 This should be dropped. As written, this applies to small generators and doesn't necessarily reflect reliaiblity of the network. 4.1.2 This is not presently modeled and will require implementation period 4.2 Why do we need to do study extreme events? The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. 4.4 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.1 to keep the related requirements together. 4.5 It is strongly suggested that this requirement is made a sub-bullet of Requirement 4.2 to keep the related requirements together.
Response: The SDT excluded loss of all units at a generating station as an extreme event for Stability. In general there are no Contingencies that could cause this to happen in a Stability time frame of interest. If there are faults or faults with breaker failure which could cause the loss of all generators at a plant, then that event is required to be studied under the other planning or extreme Events. No change made. Single phase faults with stuck breaker are included in planning event P4. Part 4.1.1: The SDT believes that Part 4.1.1 is required for BES reliability. The standard applies only to the BES as defined by your Region. The SDT believes that all generators directly connected to the BES need to be stable for single Contingencies (P1). No change made. Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. Part 4.2: The SDT disagrees and believes there is value in running extreme event analysis. No change made. Part 4.4: The SDT does not believe that combining the requirements serves any purpose. No change made. Part 4.5: The SDT does not believe that combining the requirements serves any purpose. No change made.	
PJM	in R4.1.2 – It should be made clear when the unit should be tripped. Timing is important in dynamics studies. Actual protection made need to be modeled to cover this item completely. In R4.3.3 - This protection information, is not commonly collected, at least by MMWG, and will take a great deal of time and effort to gather. R4.5 – Needs a 4.5.1 similar to 4.4.1.
Response: Part 4.1.2: Tripping the generator is no longer required. The SDT has modified Requirement R4, part 4.1.2. **Requirement R4, part 4.1.2 -** For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent	

Organization	Comments for Question 4
impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities Part 4.3.3: This does not necessarily require modeling of specific relays. Some dynamic simulation programs include a generic relay model which can easily be applied to every branch in the simulation. If this model shows impedance swings in a branch element, then either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT believes the time allotted in the Implementation Plan is appropriate. Part 4.5: The SDT does not agree that a similar requirement is needed for extreme events. No change made.	

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement. (Note – This is a new requirement.)

Summary Consideration: Several commenters expressed concern with potential double jeopardy between this standard and the VAR standards. From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.

Several commenters expressed concern that the requirement to develop a transient voltage response criterion was not limited to establishing a low voltage threshold. The SDT clarified that the minimum requirement for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. To clarify the SDT's intent, the wording of R5 has been modified as follows:

R5. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

Requirement R5 data retention: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.

Organization	Comments for Question 5
Independent Electricity System Operator	(1) We do not have any concern with the requirement as written, but suggest the SDT consider adding "and associated reactive power requirements" after "acceptable System steady state voltage limits" to take care of the concern raised in the recently posted SAR for a new VAR standard. We do not think a new standard is required for stipulating reactive power requirements as they are best addressed in the planning assessment criteria and the SOL/IROL determination requirements. (2) We do not have any comments on the measure, VRF, Time Horizon and VSL.
Response: 1) The SDT declines to add "and associated reactive power requirements". The Voltage and Reactive Planning and Control Project (2008-1) will more	

Organization	Comments for Question 5
fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. 2) Thank you.	
MAPP	A voltage criterion is addressed by the VAR standards where they are applicable to TOs and TOPs. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
NERC Standards Review Subcommittee	A. The MRO NSRS recommends the data retention for R5 and M5 be revised to change "All" to "The". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The documentation specifying the criteria since". B. This requirement should not include the criterion, "post-Contingency voltage deviation", because this criterion is not used widely enough in the industry to be a well established criterion.
Response: A. The SDT has modified the data retention for Requirement R5 to strike the word "All" and has replaced it with the word "The". **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5. B. The SDT believes that the reference to 'post-Contingency voltage deviation' is widely used and is an acceptable reference in the standard. No change made.	
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well comments from other industry members.	
Idaho Power	As worded R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."

Organization	Comments for Question 5
Bonneville Power Administration	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
NV Energy	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Pacific Gas and Electric Co.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Puget Sound Energy, Inc.	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Sacramento Municipal Utility District	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
San Diego Gas & Electric Co	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Southern California Edison (SCE)	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
SRP	As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum

Organization	Comments for Question 5
	length of time that transient voltage may remain below that level."
Western Area Power Adm - RMR	As worded, R5 is unclear. I interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. I suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
CenterPoint Energy	CenterPoint Energy is not familiar with the phrase "post-Contingency voltage deviations" and recommends that this phrase be deleted. Alternatively, the text should be revised to read "steady state post-contingency voltage limits." Including both phrases is unnecessary and confusing.
American Transmission Company	R5 This requirement should not include the criteria item, "post-Contingency voltage deviation", because this criteria is not used widely enough in the industry to be a well established criteria.
Response: The SDT believes that the term is widely used and believes that it is appropriate for inclusion in this standard. No change made.	
Deseret Power	Comments: As worded R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: "For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level."
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Omaha Public Power District	In the first sentence of the requirement text, change "voltage limits" to "voltage".
Response: The SDT believes that the use of "voltage limits" is correct. No change made.	

Organization	Comments for Question 5
TVA System Planning	In the VSL associated with R5, we believe that failure to define and document one of the criteria should be a moderate VSL, failure to define and document two criteria should me a high VSL, while failure to define and document three criteria should be a severe VSL. Otherwise failing to document only one criteria would result in a severe VSL.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R5 and M5 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE documentation specifying the criteria since”. The word in all caps is a word suggested to be added.
Response: The SDT has modified the data retention for R5 to strike the word “All” and has replaced it with the word “The”. **Requirement R5 data retention**: The documentation specifying the criteria since the last compliance audit in accordance with Requirement R5 and Measure M5.	
NorthWestern Energy	R5 could be interpreted to address both high voltage and low voltage criteria. We suggest changing the second sentence of R5 to read: “For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level.” This way high voltage is definitely excluded.
Modesto Irrigation District Transmission Planning	R5 is unclear. We interpret R5 to require entities to specify minimum voltage levels that must not be exceeded for more than a specific period of time. High transient voltages are typically not a problem. We suggest changing the second sentence of R5 to read: For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltage may remain below that level.
Response: The SDT clarified that the minimum for establishing a transient voltage response criterion was to establish a low voltage level and the maximum length of time that the transient voltages may remain below that level. **R5**. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.	
Oklahoma Gas & Electric	R5 OG&E believes the Transmission Coordinator be held accountable for the transient voltage response portion of R5. The Transmission Coordinator should coordinate this type of voltage criteria with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study with a stakeholder developed voltage criteria within the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT disagrees that only the transmission coordinator should be responsible for having a transient voltage response. Every planner, whether a	

Organization	Comments for Question 5
Transmission Planner or Planning Coordinator, needs to have a transient voltage response criterion to fully evaluate its portion of the BES.	
Midwest ISO	Requirement R5: Not all Transmission Planners have delta voltage criteria which this requirement will now require them to have. Looks like this requirement is not a one shoe fits all requirement.
Response: The SDT agrees that voltage criteria may not be a "one size fits all" criteria. This requirement requires each Transmission Planner and Planning Coordinator to have criteria for acceptable voltage limits.	
SERC Dynamics Review Subcommittee (DRS)	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-contingency voltage deviations, and transient voltage response. How would an nteraction with a third party system be handled? For example a contingency causes a voltage deviation on one system that is within thevoltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criterion.
SERC Planning Standards Subcommittee	The content in the severe VSL column should be split among the lower, moderate, and high categories, with failure to include one element as Moderate and two elements as High. It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, post-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party system be handled? For example a contingency that occurs on a system that is within their voltage deviation criteria, but causes a voltage deviation violation on a neighboring system that has a more stringent criteria.
Response: The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified.	
Lafayette Utilities System	The modified version resolves the confusion noted by several commenters in the earlier draft.
Response: Thank you.	
US Bureau of Reclamation	The requirement in Table 1 is for Planning Authority and Transmission Planner to establish accceptable voltage deviations and limits. The requirement only indicates the that each shall have a criteria. That does not imply an agreement on a single limit or deviation allowable under a System Steady State post-contingency condition.
Response: The SDT agrees with your statement.	
Progress Energy Carolinas	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards. The voltage and var criteria will also be required in VAR-001 and 002.

Organization	Comments for Question 5
TIS	There appears to be a double-jeopardy issue related to voltage performance criteria related to the VAR Standards.
National Grid	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace “Each Transmission Planner and Planning Coordinator” with “Each Transmission Planner OR Planning Coordinator”.
Northeast Power Coordinating Council--RSC	Voltage criteria are addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure. Also, implementing transient voltage criteria will require time.Replace “Each Transmission Planner and Planning Coordinator” with “Each Transmission Planner OR Planning Coordinator”.
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: “Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations.” The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards.	
Gainesville Regional Utilities	Voltage considerations can get lost in the various studies. This requirement brings focus to the voltage component which it rightly deserves.
Response: Thank you.	
Central Maine Power Company	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read “Each Transmission Planner OR Planning Coordinator “ Need time to implement transient voltage criteria.
ISO New England	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read “Each Transmission Planner OR Planning Coordinator “ Need time to implement transient voltage criteria.
United Illuminating	Voltage criteria is addressed by the VAR standards. Including a voltage requirement in the planning standards appears to be creating a double-jeopardy exposure.R5. Change to Read “Each Transmission Planner OR Planning Coordinator “ Need time to implement transient voltage criteria.

Organization	Comments for Question 5
Response: As for the double jeopardy comment - From the ERO Rules of Procedure, Appendix 4B- Sanction Guidelines, Section 3.10 Multiple Violations: "Strictly speaking, NERC or the regional entity can determine and levy a separate penalty or sanction, or direct remedial action, upon a violator for each individual violation. However, in instances of multiple violations related to a single act or common incidence of noncompliance, NERC or the regional entity will generally determine and issue a single aggregate penalty, sanction, or remedial action directive bearing reasonable relationship to the aggregate of the related violations. The penalty, sanction, or remedial action will not be that determined individually for the least serious of the violations; it will generally be at least as large or expansive as what would be called for individually for the most serious of the violations." The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards. The implementation Plan allows 24 months before Requirement R5 becomes effective.	
Oncor Electric Delivery	Voltage criteria is addressed within the VAR standards. This appears to be redundant.
Response: The existing VAR standards (VAR-001-1a and VAR-002-1b) address the operational time horizon but do not address the planning horizon. NERC Standards Project 2008-1 is under development and the SAR addresses the planning horizon. As this project moves forward, the Standards Drafting Team for Project 2008-1 will more fully develop the requirements for reactive planning and will evaluate whether those requirements should reside in the TPL standard or the VAR standards to ensure that it is not a redundant requirement.	
American Electric Power	We believe that it is appropriate to eliminate the reference to transient voltage response as it is duplicative and unnecessary. System stability is already better addressed by other performance requirements defined in this standard.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and that it is complementary to the other performance requirements in this standard, not duplicative.	
FirstEnergy Corp	We concur with the inclusion of R5 and the criteria needed for steady-state voltage limits, post-contingency deviations and the transient voltage response for its System. In regards to the transient voltage criteria, its our understanding that the this criteria is for planning purposes only and not intended for operation time horizon evaluations being performed by the TOP.
Response: The SDT agrees that the requirement for criteria for transient voltage responses is for planning studies and does not address operating studies since they are outside the scope of this standard.	
Ameren	With respect to specifying a voltage level and maximum duration for transient voltage response, does it make sense for each Transmission Planner to have their own criteria? Should we be meeting an industry standard such as the ITI (CBEMA) Curve published by the Technical Committee 3 (TC3) of the Information Technology Industry Council (ITI, formerly known as the Computer & Business Equipment manufacturer's Association) and available at www.itic.org? Meeting any of the criteria to be developed for Requirement R5 will depend on the load model assumptions used.It is stated that the Transmission Planner and Planning Coordinator shall have criteria specifying voltage limits, pos-Contingency voltage deviations, and transient voltage response. How would an interaction with a third party be handled, particularly if one entity has more stringent criteria?

Organization	Comments for Question 5
	The content in the severe VSL column should be split among the lower, moderate, and high categories.
Response: The SDT believes that each Transmission Planner and Planning Coordinator should have a criteria and has not placed bounds on how to establish the criteria. This standard places the requirement for performance on each entity's portion of the BES (Requirement R2). In addition, Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 require the coordination of the Contingencies and Requirement R8 requires the distribution of the Planning Assessment. These requirements will ensure that third party impacts are identified. The SDT believes that establishing the criteria for acceptable voltage deviations should be a binary VSL. No change made.	
PJM	Remove any mention of transient voltage response. Very few entities can perform this type of analysis.
Response: The SDT believes that a criterion should be established for transient voltage response by each Transmission Planner and Planning Coordinator and disagrees with the assertion that very few entities have the capability to complete this type of analysis. No change made.	

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made clarifying changes based on industry comments as follows: **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding**M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention** - The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Comments for Question 6
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
Florida Municipal Power Agency, and its Member Cities	FMPA suggests adding the word "potential" into " identify the potential for System instability". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then do a voltage stability study, or something like that. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
FRCC Transmission Working Group	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in their analysis to identify system instability /deleted/ for /deleted/ conditions such as cascading outages, voltage instability, or uncontrolled islanding." As written originally it could be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage. the word "potential" into "identify the potential for System instability ". The criteria and methodology may be used to determine if further analysis is warranted, e.g., if steady state voltages fall below 0.9 per unit, then duedo a voltage stability study. Going below 0.9 does not mean voltage collapse, but, it may be an indicator to study it; hence, the word "potential".
Response: The SDT disagrees with your suggestion of adding the term 'potential' in Requirement R6. The Standard does not preclude the application of criteria or methodology to determine potential instability. No change made.	
Orlando Utilities Commission	For R6 please consider the following revision: "Each TP and PC shall define and document within their planning assessment any criteria or methodology used in <<their>> analysis to identify system instability //for// conditions such as cascading outages, voltage instability, or uncontrolled islanding." Adding the text in <<>> and deleting the text in ////. As written originally it could

Organization	Comments for Question 6
	be taken to be the methods for determining if you have instability during a cascading outage, rather then the methods for determining if you are at risk for instability like a cascading outage.
Response: The SDT disagrees with your assessment that the language of "… criteria or methodology used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding" is misleading. The System instability applies to the cascading outages, voltage instability, OR uncontrolled islanding, not just to cascading outages. No change made.	
Gainesville Regional Utilities	I believe that this requirement is better defined and documented at the regional level with all involved parties contributing. If consensus is not achievable, then the exception utilities can create their own knowing that they need technically valid references to support their position.
Response: The SDT disagrees as it is better to allow the individual a Transmission Planner or Planning Coordinator to determine this versus the region as the region could be quite varied. The Requirement does not preclude the region from doing as you suggest with coordination in the region. No change made.	
FirstEnergy Corp	If an entity is required to adhere to its Facility Ratings, how is it feasible that a cascade violation would occur? FirstEnergy questions the need for this review based on Table 1 performance requirements and the need to adhere to Facility Ratings.
Response: This may not be an issue in the application of this criteria or methodology for planning events P0 through P7, however, this needs to be available when evaluating System response when applying extreme events.	
Arizona Public Service Co.	It is not clear who this applies to. Is it both TP and PC individually, or one of the two, or both jointly?
Response: The requirement is for both.	
American Electric Power	M6 does not appear to align with the content of R6. M6 needs to be reworded to reference documentation of criteria or methodology rather than studies. Corresponding changes will also need to be made to the corresponding bullet under Data Retention.
Manitoba Hydro	The R6 text does not match the Data Retention 6th bullet text "studies performed". The Retention 6th bullet text should be updated to reflect the R6 text "criteria or methodology used in the analysis to identify System instability".The R6 text does not match the M6 text. The M6 text should be revised as follows: replace "studies utilized in preparing the Planning Assessment" with "criteria and methodology to identify System instability used within its analysis".
Response: The SDT agrees and has changed the language of Measure M6 and also the language for Data Retention. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention -** The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last	

Organization	Comments for Question 6
compliance audit in accordance with Requirement R6 and Measure M6.	
Ameren	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Dynamics Review Subcommittee (DRS)	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology but not a study.
Southern Company	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study. Replace the word "studies" with "criteria or methodology".
TVA System Planning	M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
SERC Planning Standards Subcommittee	Comments: M6: The wording on this measure appears to have been copied from M3 or M4 but is not appropriate since R6 addresses criteria and methodology and not a study.
Response: The SDT agrees and has changed the language of Measure M6. **M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “THE studies performed in support”. The word in caps is a word suggested to be added.
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R6 and M6 be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support”.
Response: The SDT agrees with your suggestion of changing the “All” to “The” in the data retention section for Requirement R6 and Measure M6. **M6.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6. **Requirement R6, data retention -** The documentation specifying any criteria or methodology utilized in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.	
Duke Energy	R6 includes the phrase “cascading outages”. We believe that the word “cascading” should be the capitalized NERC-defined

Organization	Comments for Question 6
	term "Cascading".
Response: The SDT agrees with your suggestion of changing "cascading" to Cascading". **R6**. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading , voltage instability, or uncontrolled islanding.	
Oklahoma Gas & Electric	R6 OG&E believes the Transmission Coordinator be held accountable for R6. The Transmission Coordinator should coordinate this type of study/documentation with the Transmission Planner for a regional look of the whole system. For example Southwest Power Pool should coordinate this type of study/documentation with the members of the Southwest Power Pool to better examine the entire region of the Southwest Power Pool. We do not see the need to duplicate the work.
Response: The SDT assumes that you mean Planning Coordinator. The requirement is for both entities.	
Tri-State Generation and Transmission Association	R6 seems OK but check M6. Should this refer to R2 and not R6?
Independent Electricity System Operator	We do not have any comments on the requirement, VRF, Time Horizon and the VSL. However, Measure M6 (which refers to "studies utilized in preparing the Planning Assessment") does not seem to be relevant to Requirement R6, which deals with defining and documenting the criteria and methodology used in the analysis to identify System instability.
Response: The SDT agrees and has changed the language of Measure M6. **M6**. Each Transmission Planner and Planning Coordinator shall provide evidence, such as electronic or hard copies of documentation specifying any criteria or methodology used in the analysis to identify System instability that was utilized in preparing the Planning Assessment in accordance with Requirement R6.	
MAPP	Suggest removing "Transmission Planner" since the PC performs the assessment.
Response: The SDT disagrees with your comment as both entities should be documenting their criteria.	

7. **Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.**

Summary Consideration: The SDT modified Measure M7 to clarify the supporting documentation used to establish the individual and joint responsibilities for performing the required studies. The SDT also clarified the data retention associated with Requirement R7. Measure M7 and the data retention associated with Requirement R7 now read:

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

Requirement R7 data retention: The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Organization	Comments for Question 7
ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? Would it be appropriate to say: "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies and assessments."* What kind of documentation will be acceptable to demonstrate "each entity's individual and joint responsibilities"?
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. To address your concerns the SDT has changed Measure M7 to clarify the type of supporting documentation that could be used to establish individual and joint responsibilities for performing the required studies. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.	
American Transmission Company	Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section.
Response: The SDT sees no additional clarity being provided by your suggested wording. No change made. The SDT discussed the change and based on industry input decided not to change the order of the requirements.	

Organization	Comments for Question 7
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.	
CenterPoint Energy	CenterPoint Energy believes R7 relates to matters best addressed through registration, such as JROs or delegation agreements. If other commenters agree, CenterPoint Energy recommends that R7 be deleted.
Response: This requirement was inserted to address industry concern regarding the potential for duplication of work. No change made.	
TVA System Planning	In the VSL associated with R7, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The SDT believes that procedurally, Requirement R7 is binary. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
NERC Standards Review Subcommittee	The MRO NSRS recommends the data retention for R7 and M7 be revised to delete "All". The word "All" is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: "The current, in force agreement on identified responsibilities, as well as such agreements in force".
Response: The SDT agrees that the proposed change to Measure M7 and the data retention removes the potential for an unintended interpretation. **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	
Tri-State Generation and Transmission Association	R7 - Duties of the Planning Coordinator are being created and changed as we go along, like changing rules of a flag football game as it is played. Is there any requirement that every TP have a PC? As far as we know, the PC was introduced as an additional authority level for regional or inter-utility study work. Previous R7 wording asked PCs and TPs to work together. The present wording implies that every TP must have a PC which is a separate entity, and that PC would dictate study responsibilities. The wording of R4.4.1 seems much better in this regard.

Organization	Comments for Question 7
Response: It does not create the requirement that each Transmission Planner report to a Planning Coordinator, that relationship is defined in the Functional Model This requirement specifies that, if there is a relationship between a Transmission Planner and Planning Coordinator there is no need for duplicate analysis if each entity agrees on the delegation of work. No change made.	
NYISO	R7. - The NYISO requests clarification as to whether the PC will be expected to distribute the TP Planning Assessments as part of its coordination requirement?
Response: This standard does not require the Planning Coordinator to distribute the individual Transmission Planner assessments.	
MAPP	Suggest moving this requirement to the head of the list. It's a basis for the rest of this standard.
Response: The SDT discussed the change and based on industry input decided not to change the order of the requirements.	
Orlando Utilities Commission	The intent is much clearer, thank you for revising this.
Oklahoma Gas & Electric	We agree that it should be clearly stated who does what between the Transmission Planner and the Planning Coordinator. We feel like this will eliminate duplication of work and create a better overall regional examination of the electric grid.
Gainesville Regional Utilities	Looks good.
Response: Thank you.	
Florida Municipal Power Agency, and its Member Cities	The Measure and Data Retention for R7 is ambiguous. While the measure could be interpreted as not requiring a contract, the data retention uses the words "in force agreement" which implies a formal contract, where roles and responsibilities could very well be assigned in regional planning committee minutes and ensuing e-mail correspondence. Suggest changing the words to "Documentation of agreement on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence" in both locations.
Response: The SDT agrees that the proposed changes to Measure M7 and the data retention remove the potential for an unintended interpretation. Measure M7 and the data retention associated with Requirement R7 now read: **M7.** Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7. **Requirement R7 data retention:** The current, in force documentation for the agreement(s) on roles and responsibilities, as well as all such documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.	

8. Requirement R8 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT believes revisions to Requirement R3, parts 3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planners and Planning Coordinators analyze Table 1 events outside their Systems for reliability impacts. The proposed, new Requirement R8 (old Requirement R7) requirement (below), will ensure appropriate information is exchanged between Transmission Planners and Planning Coordinators for sharing of information, review, and coordination of plans in conformance with Order 693 paragraph 1755 and 1756 expectations. The SDT believes the NERC Rules and Procedures and delegation agreements cover existing TPL-005 & -006 assessment requirements for regional and inter-regional assessments. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

R8 data retention. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Comments for Question 8
Independent Electricity System Operator	(1) No comments on the requirement, measure, VRF and Time Horizon. 3) VSLs:(a) We do not agree with the Severe VSL condition. In our view, distributing planning assessment results is the intent of the requirement; it is more important to share results than to field questions from recipients of the results. Assigning a Severe VSL for failing Part 8.1 puts the driver at the wrong place.(b) The condition under Low and High seems to be the same. In the Low, failing to distribute the results to ANY ONE of the TPs and PCs means none, which is the same as the condition for High unless the condition under Low really means failing to distribute the results to ONE of the TPs and PCs whereas the High really means failing to distribute the results to two or more of the TPs and PCs. If this is the proper interpretation, then we'd suggest the VSLs be revised as follows:Low: failing to respond to comments within 90 daysHigh: failing to distribute the results to one of the TPs and PCsSevere: failing to distribute the results to two or more of the TPs and PCs.Alternatively, a Moderate can be added to capture the condition for failing to distribute the results to two of the TPs and PCs, while the Severe can become failure to distribute the results to three of the TPs and PCs.

Response: The SDT disagrees because the requirement's focus is on coordination of planning. If questions/concerns are not responded to, coordination of planning is not being accomplished. The VSLs related to failing to distribute results are appropriate. However, the SDT agrees that the Lower VSL is unclear and will make a change to delete the word "any". In addition, the SDT has modified the Lower and High VSL wording to be clearer.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

ERCOT ISO	* Will any agreements made in R7 override the "each TP and PC" requirement? To clarify this, the requirement could be rephrased: "In accordance to the responsibilities assigned in R7, the responsible Transmission Planners and Planning Coordinators shall distribute?. "* Include "within the interconnection" such as: "distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners within the interconnection and to any functional entity that indicates a reliability related need for the Planning Assessment results"* Should "reliability related need" be defined? This appears in multiple standards.

Response: No, the agreements made in Requirement R7 pertain to performance of the required studies and will not override the Planning Coordinator and Transmission Planner's responsibilities under Requirement R8 relating to distribution of Planning Assessments.

Organization	Comments for Question 8
The SDT does not believe the suggested language adds any clarity. No change made. A definition is not required. The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Northeast Utilities	[R8.1] There is no statute of limitation for comments, nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted. If this requirement is retained the following is suggested: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results".
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The word "indicates" has been changed to "has" to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear. Both the Transmission Planner and Planning Coordinator may be asked for their Planning Assessment by an entity with a reliability related need. Therefore the statement must apply to both the Transmission Planner and Planning Coordinator. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Oncor Electric Delivery	8.1 This requirement should be removed because it appears redundant to FERC 890. (suggest having one statement or the other) However, if it isn't, then the Term "documented" in R8.1 the term documented needs to be defined. Suggest adding the qualifier "written " i.e., "If a recipient of the Planning Assessment results provides "documented written" comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a "documented written" response to that recipient within 90 calendar days of receipt of those comments. The requirement to distribute reports to entities with "need" has very significant CEII implications. This should be tightened to a "bona fide reliability need" for the information, requiring CEII or confidential material handling procedures. R8, 8.1, and Measurement M8 There is no statute of limitation for comments (Suggest clarifying what we mean here assume we are note referring to the NERC Standards Commenting Process), nor is there a limit on the number of comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results. [I think there are issues still with this language. I think it needs to say "and to the functional entities that the Planning Coordinator recognizes as having a reliability need for the Planning Assessment results."]

Organization	Comments for Question 8
	Compliance 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. This seems to be a nuisance requirement to get in trouble for. [Requirement is to keep 3 years of notifications related to R8 & 8.1.]

Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Order 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives.

The present wording is in other approved standards and is sufficiently clear based on experience to date. Bona fide does not add significant clarity.

Control of CEII and control of competitive market information per Standards of Conduct are a fundamental expectation of all industry participants and is not required in the standard.

The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT also disagrees that there should be a limit to the number of questions allowed related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT agrees the wording is somewhat unclear and will clarify by adding “adjacent” before Transmission Planner. The word "indicates" has been changed to “has” to be clearer. This revised wording has the same meaning as the suggested wording and is sufficiently clear.

> **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes. No change made.

Organization	Comments for Question 8
Progress Energy Florida, Inc.	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF’s previous comments to this effect.

Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.

Organization	Comments for Question 8
CenterPoint Energy	CenterPoint Energy believes R8 is over-reaching and recommends deleting it. CenterPoint Energy is particularly concerned about requiring assessments to be distributed to “any functional entity that indicates a reliability related need”. There is already a process in place for entities to request and receive the FERC Form 715 submittals of other entities. FERC’s process appropriately recognizes and addresses CEII issues and imposes a requirement that the entity demonstrate need for the information and that the industry complies with certain security-related requirements. Beyond CEII matters, transmission planning information can have implications for market entities bidding on congestion rights in competitive energy markets. Therefore, the dissemination of transmission planning information may be governed by the regulatory authority having jurisdiction over the market functions, which is not necessarily FERC in all cases. In any case, given the availability of the FERC 715 process, there is no need for a somewhat duplicative requirement in this standard. Accordingly, CenterPoint Energy recommends that R8 be deleted in its entirety.

Response: Requirement R8 is necessary to ensure that appropriate coordination of planning occurs and supports regional assessments performed under NERC delegation agreements.

Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given

Organization	Comments for Question 8
planning assessments. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. FERC 715 is not adequate to achieve these objectives. No change made.	
Bonneville Power Administration	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Modesto Irrigation District Transmission Planning	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
NV Energy	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Pacific Gas and Electric Co.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Puget Sound Energy, Inc.	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Sacramento Municipal Utility District	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
San Diego Gas & Electric Co	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Southern California Edison (SCE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
SRP	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?
Utility System Efficiencies, Inc. (USE)	Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?

<table>
<tr><th>Organization</th><th>Comments for Question 8</th></tr>
<tr><td>Western Area Power Adm - RMR</td><td>Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?</td></tr>
<tr><td>Deseret Power</td><td>Comments: Clarity is needed in the phrase functional entity in R8. Is this referring to the entities identified in the Functional Model or something else?</td></tr>
<tr><td colspan="2">Response: Yes - The NERC Reliability Functional Model defines the meaning of the term "functional entity".</td></tr>
<tr><td>SERC Planning Standards Subcommittee</td><td>Comments: R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel.

R8: It is not clear if the requirement to provide assessment results to adjacent PCs and TPs is required, or only upon a reliability related request.R8: The PC and TP responsibilities should be stated separately for clarity.

Part 8.1: It is not clear what the form of the response to the comments should be “ would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment”The requirement needs to be revised to make the above points clear.</td></tr>
<tr><td colspan="2">Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments.

The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. The word "indicates" has been changed to “has” to be clearer.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.</td></tr>
<tr><td>Orlando Utilities Commission</td><td>Excellent requirement, thank you for revising this</td></tr>
<tr><td colspan="2">Response: Thank you.</td></tr>
<tr><td>Southern Company</td><td>For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request."

For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or</td></tr>
</table>

Organization	Comments for Question 8
	Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner and added wording requiring a written request. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT has altered the wording of Requirement R8 to provide clarity and to attempt to alleviate your concern.	
Manitoba Hydro	Is there a need to retain comments and responses to comments for Requirement R8?
Response: Yes, see Measure M8 and the following changes to 1.4 Data Retention**.** **R8 data retention**. Three calendar years of the notices and other documentation employed in accordance with Requirement R8 and Measure M8	
SCE&G	It is not clear if the requirement to provide assessment results to adjacent Planning Coordinators and Transmission Planners is always required or only upon a reliability related request.
Response: The SDT considers the distribution to Planning Coordinators and Transmission Planners as mandatory and has changed the wording of Requirement R8 to address the wording for other functional entities. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
MidAmerican Energy Company	MidAmerican commends the SDT for their hard work on this standard. MidAmerican does have comments about this requirement though. MidAmerican asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows "adjacent Planning Coordinators and ADJACENT Transmission Planners and to any REGISTERED functional entity"? The words in all caps are words that MidAmerican suggests are added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the requirement to provide the Planning Assessment to apply. MidAmerican asks that the low VSL for R8 be revised to delete the word "any" from the requirement so that the requirement will read "The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners".
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding "registered" is unnecessary because it is understood that it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	

Organization	Comments for Question 8			
The SDT agrees and will make change to delete the word "any".				
R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
Progress Energy Carolinas	Need to define "adjacent" Planning Coordinators. Does this mean a neighbor with at least one joint interconnection? The requirement to provide the Planning Assessment "to any functional entity that indicates a reliability related need" should be made subject to applicable confidentiality and CEII provisions.			
Response: The SDT believes "adjacent" is an understood term and would apply to any neighbor with a joint Interconnection. No change made. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. No change made.				
Tri-State Generation and Transmission Association	R8 - We find that web-site posting would be sufficient distribution if it were not for the need for auditability. Please consider a way to qualify web-posting as an acceptable distribution method.			
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and 1.4 under compliance monitoring. No change made.				
NYISO	R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should not be required to send their assessment to TPs not in their footprint. R8.1: This should not be required until the Assessment is complete and posted. Additionally, this could be an administratively intense task to respond to each and every comment and document that a response is made within 90 days. Is there any room for an extension to this requirement?			
Response: The SDT disagrees, the broader communication is necessary to achieve appropriate coordination. No change made. The requirement is to distribute the results of completed Planning Assessments, then respond to comments. Therefore the assessment is posted and complete before				

Organization	Comments for Question 8
comments can be received and responded to. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. No change made.	
Oklahoma Gas & Electric	R8 OG&E believes the Transmission Coordinator be held accountable for R8 and coordinate this type of data exchange to ensure a regional coordination effort is achieved.
Response: The SDT believes you were referring to Planning Coordinator in your comment. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Xcel Energy	R8 Xcel Energy appreciates the language stating “reliability need” however it is unclear as to what constitutes this or who would make that determination. Please clarify so as to avoid future disputes on providing or obtaining the information.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. No change made.	
Central Maine Power Company	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:”Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results.” Additionally, there is no deadline for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
ISO New England	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results. Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. 1.4 Data Retention: The last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard	

Organization	Comments for Question 8
and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. No change made. The SDT believes that data retention is a necessary function as outlined in the guidelines. No change made.	
United Illuminating	R8, 8.1, and Measurement M8 This standard should not be used to remedy deficiencies in meeting the coordination requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results." Additionally, there is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. Measures M1:It is not practical to retain system model information in a hard copy form. This provision could be dropped. Compliance: D 1.1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is. Also, the last bullet is unnecessary and should be deleted from the standard.
Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made. This revised wording has the same meaning as the suggested wording and is sufficiently clear. No change made. The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. Since Measure M1 states that either electronic OR hard copy format is required, the SDT believes that no changes are required since either of the formats is acceptable. An example of a hard copy of a system model is having printouts of each individual bus showing Load, Transmission line, generator, capacitors, etc., connected to that bus with associated impedances, ratings, etc. The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the	

Organization	Comments for Question 8
existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data.	
Ameren	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. R8.1: It is not clear what the form of the response to the comments should be " would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment" The audience of those able to provide comments to the assessments should be appropriately limited, and not open to anyone who wishes to comment.
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. No change made.	
SERC Dynamics Review Subcommittee (DRS)	R8: It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information to access the information. Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate personnel. For additional clarity in who should receive the assessment, we recommend replacing "indicates" with "has" and adding words to the end of the sentence so that it states the following: "and to any functional entity that has a reliability related need for the Planning Assessment results and provides a written request. "R8: The PC and TP responsibilities should be stated separately for clarity. Part 8.1: It is not clear what the form of the response to the comments should be. Would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment? The requirement needs to be revised to make the above point clear.? For Part 8.1, we do not believe the intent is for casual emails to be documented and formally responded to. And we do not believe that anyone who happens to receive the assessment should be able to comment. Therefore, we recommend the following wording: "If one of the above named entities provides formal written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments." If these recommendations are accepted, then the wording of M8 would have to change accordingly.

Organization	Comments for Question 8
Response: The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording and is sufficiently clear. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. The SDT believes that the requirement limiting distribution to adjacent Planning Coordinator/Transmission Planner's and other functional entities with a reliability related need who request it appropriately limits those commenting. The revised wording has the same meaning as the suggested wording which is sufficiently clear.	
MAPP	R8: Remove Transmission Planners: Each PC shall distribute it Planning Assessment to adjacent PC and to any registered function entity that indicates a reliability need for the Planning Assessment results. R8.1 Remove Transmission Planners from subrequirement.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments and respond to comments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Midwest ISO	Requirement R8- It should be made clear that a TP should not be required to send their assessment to adjacent PCs. Likewise the PCs should be required to send their assessment to TPs not in their footprint. Please consider the following language change for R8:Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any other Planning Coordinators who indicate they have a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planner and to any other Transmission Planner who indicates they have a reliability related need for the planning assessment results. Requirement R8.1: This should be clarified such that this requirement is only required on Assessments that are completed and posted as final. If not, this could be an administratively burdensome task for an entity to have to respond to each and every comment and then document that they did respond within 90 days. Please consider the following language changes for R8.1If a recipient of the Planning Assessment's final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The Requirement R8 requirement is to distribute Planning Assessment results associated with this standard. Therefore Requirement R8, part 8.1 only requires response to comments on the applicable assessment results. No change in wording is necessary.	

Organization	Comments for Question 8
Northeast Power Coordinating Council--RSC	Requirements R8, 8.1, and Measure M8--There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments. There is no statute of limitation for comments. There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed. This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted. If this requirement is retained the following revision to Requirement 8 is suggested:"Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognize as having a reliability need for the Planning Assessment results." Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an "or" such that one of them must retain the data and it can be up to them as to who it is? 1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measure M8. "Three calendar years of the notifications" seems to be an unnecessary requirement, and should be deleted. As an alternative to deletion, the implementation of a rolling three calendar years of notifications could be considered.

Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days.

The SDT disagrees, this communication is necessary to achieve appropriate coordination.

The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict.

The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made.

The SDT agrees the wording could be clearer and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to "has" to be clearer. The other revised wording has the same meaning as the suggested wording.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent

Organization	Comments for Question 8
Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information. The SDT believes that both the Transmission Planner and Planning Coordinator have the responsibility for data retention. Therefore, the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.	
Hydro-Québec TransEnergie (HQT)	Requirements R8, 8.1, and Measurement M8 There are a number of concerns with these requirements. There needs to be a specified time period upon which comments must be received. As written, there is no sunset on when comments may be made and therefore they must be responded to. Additionally, it is not clear if the 90-day response time may extend beyond the end of the year to maintain and maintain annual compliance. R8 also causes redundancy of distribution of assessments.Suggested revised Requirement R8 to say: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to functional entities that demonstrated a reliability need with concurrence from their planning coordinator for the Planning Assessment results.
Response: The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. The SDT's intent is that compliance would be judged by whether the comment was responded to in the required 90 days. The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
US Bureau of Reclamation	Results of the Planning Assessments should be coordinated with all owner entities who all share in system reliability. Any owner that may choose to implement a Corrective ACtion Plan item should have access to the basis for the need.
Response: The SDT agrees and believes Requirement R8 facilitate the necessary interaction between reliability related entities. No change made.	
TIS	Term “document” in R8.1 the term documented needs to be defined. TIS suggests using the term “written “ i.e., “If a recipient of the Planning Assessment results provides documented written comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented written response to that recipient within 90 calendar days of receipt of those comments. ”The requirement to distribute reports to entities with “need” has very significant CEII implications. This should be tightened to a “bona fide reliability need” for the information, requiring CEII or confidential material handling procedures. Other general comments:1. Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft.
Response: The present wording is in other approved standards and is sufficiently clear based on experience to date. Control of CEII is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given	

Organization	Comments for Question 8
planning assessments. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the Summary Considerations for Question 10.	
NERC Standards Review Subcommittee	The MRO NSRS asks that the SDT revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity”? This MRO NSRS suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
Response: The SDT agrees and will clarify by adding "adjacent" before Transmission Planner, but the SDT believes adding “registered” is unnecessary because it is understood as it relates to NERC Reliability Standards. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
Florida Power and Light	The requirement to distribute the Planning Assessment should not mandate distribution of a document but should be more flexible and allow for making the Planning Assessment available, such that those entities that need the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Response: The SDT believes Requirement R8 must be a standards requirement and ensures communication of information necessary for regional assessments. No change made.	
NorthWestern Energy	The term "functional entity" needs to be defined.
Response: The NERC Reliability Functional Model defines the term "functional entity".	
Gainesville Regional Utilities	The wording could be a little better to indicate that the PC and TP should always get each others planning assessments, but other entities need to indicate a reliability related need to get the same. I suggest making a second sentence and eliminating the word “and”.
Response: The SDT agrees that the wording could be a little better and will clarify by adding "adjacent" before Transmission Planner. **R8**. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.	
National Grid	This standard should not be used to remedy deficiencies in meeting the requirements of FERC Order 890. Therefore these should be deleted.

<table>
<tr><th>Organization</th><th>Comments for Question 8</th></tr>
<tr><td></td><td>If this requirement is retained the following is suggested: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to their adjacent Planning Coordinators and Transmission Planners, respectively, and to the functional entities that the Planning Coordinator and Transmission Planner recognizes as having a reliability need for the Planning Assessment results.

Additionally, there is no statute of limitation for comments.

There is also potential conflict with the deadline for completing a study and when comments may be submitted (e.g. comments are received the day before the study is to be completed.) These issues must be addressed.

Compliance: 1.4 Data Retention: The Transmission Planner and the Planning Coordinator may not be using the same software. If both are required to store the data, do they both have to have the software to use the data? Can this be changed to an “or” such that one of them must retain the data and it can be up to them as to who is it.

1.4 Data Retention, last bullet - this relates back to Requirements R8, 8.1, and Measurement M8. “Three calendar years of notification” seems to be a nuisance requirement to get in trouble for. This is unnecessary and should be deleted.</td></tr>
<tr><td colspan="2">Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of the regional assessments required under NERC delegation agreements will meet these objectives. No change made.

The SDT agrees and will clarify by adding "adjacent" before Transmission Planner. The word "indicates" has been changed to “has” to be clearer. The other revised wording has the same meaning as the suggested wording which is sufficiently clear.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity that has a reliability related need and submits a written request for the information.

The SDT disagrees that there should be a statute of limitation for asking questions related to coordination of planning and believes parties will act appropriately. No change made.

The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict.

The SDT believes that both the Transmission Planner and Planning Coordinator have this responsibility for the data retention. Therefore the SDT believes that the existing language is adequate and that no changes are required. The SDT believes that both should have the necessary software for using the data. No change made.

The SDT believes that retaining the documentation for 3 years is consistent with other standards and appropriate for audit purposes.</td></tr>
<tr><td>TVA System Planning</td><td>TVA believes that the TP and PC are unnecessarily duplicating work as shown in R8 and in M8. TVA believes that just the PC should be responsible for this coordination. R8:

It is not clear whether the assessment results must be distributed to all parties of interest, or if it would be sufficient to post the assessment at a central location, and distribute information necessary to access the results.

Also, FERC Standards of Conduct issues would come into play in assuring that the information is available only to appropriate</td></tr>
</table>

Organization	Comments for Question 8
	personnel. R8.1: It is not clear what the form of the response to the comments should be “ would an acknowledgement be sufficient, or would it be necessary to pursue a process of examining comments in detail and revising and reissuing the corresponding assessment”
Response: The SDT believes both the Transmission Planner and Planning Coordinator must distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. The standard does not specify the mechanics of distribution of the information, only that it must occur. The method proposed would be acceptable as long as it met Measure M8 and Section 1.4 under compliance monitoring. Control of competitive market information per Standards of Conduct is a fundamental expectation of all industry participants and the "reliability related need" restriction ensures only appropriate parties must be given planning assessments. The standard should not specify the means of providing and responding to comments, but ensures that appropriate communication is initiated. No change made.	
SRC of ISO/RTO	Under R8 it should be made clear that a TP should not be required to send their assessment to adjacent PCs and that PCs should not be required to send their assessments to TPs not in their footprint. Under R8.1: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.This should not be required until the Assessment is final and could be an administrative intense task. The following wording is suggested for R8:R8. Each Planning Coordinator shall distribute its planning assessment results to adjacent Planning Coordinators and to any Planning Coordinator who indicates a reliability related need for the planning assessment results. Each Transmission Planner shall distribute its planning assessment results to adjacent Transmission Planners and to any other Transmission Planner who indicates they have a reliability need for the planning assessment results. R8.1 If a recipient of the Planning Assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. AESO does not comment on VSLs or VRFs.
Response: The SDT believes both the Transmission Planner and Planning Coordinator must broadly distribute their assessments to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made. The requirement is to distribute the results of the completed Planning Assessments associated with this standard therefore all related supporting studies are complete and there is no potential conflict. The SDT recognizes this fact and believes 90 days should be sufficient to develop a response. The SDT disagrees with the suggested limitations and believes both the Transmission Planner and Planning Coordinator must distribute their assessments to the applicable entities cited in the requirement to meet the overall intent of Requirement R8 and achieve appropriate coordination. No change made.	
Pepco Holdings, Inc. - Affiliates	While the SDT has stated in the Description of Current Draft that the issues of TPL-005 and TPL-006 have been addressed. It is not clear to PHI Affiliates that this is true. It is not evident how wide area planning is performed. Requirement 2 states Each

Organization	Comments for Question 8
PHI	Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES.

Response: The SDT seeks to retire the existing TPL-005 & -006 while continuing to meet the purpose of their requirements. FERC Orders 693 and 890 each provide expectations and direction to the ERO regarding enhancement of regional coordination and planning. The SDT believes the inclusion of Requirement R8 in the standard and performance of regional assessments will meet these objectives.

Organization	Comments for Question 8
FRCC Transmission Working Group	With regards to the High VSL, what about entities that indicate a reliability related need for the Planning Assessment? Should this be part of the High VSL? Consider changing the requirement to distribute the Planning Assessment to become more flexible and allow for making the Planning Assessment available to those entities that indicates a need. Consider revising as follows:Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. The definition of "Known Commitments" should explain how that would diferentiate between Planned Commitments

Response: The SDT agrees and will add those with a reliability related need to the Lower and High VSL.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to one of its adjacent Transmission Planners or adjacent Planning Coordinators, and to one functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners or adjacent Planning Coordinators, and to any functional entity that has a reliability related need and has submitted a written request for the information, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

The proposed revised wording is essentially the same as the current wording and does not provide any additional clarity. No change made.

The SDT believes that the existing language regarding known commitments is adequate and no further change is required.

9. The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: The SDT received several comments on definitions. The following summarizes the questions and response on the definitions. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition.

Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition.

The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential load.

Consequential Load Loss: Due to comments in prior postings, the SDT has elected to define Consequential Load specific to Load that is lost due to a fault. Non-Consequential Load has been defined to be all else, except as noted. That which has been noted is excluded from coverage by the standard. So it is not necessary to include the noted exclusions from the Non-Consequential Load Loss definition in the Consequential Load Loss definition.

Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.

Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon.

Year One is not considered to be the immediate year following the current year, as suggested by some, because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame.

The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.

With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.

Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss.

Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity.

Steady State: 'Steady State' was changed to 'steady state', so no definition is required.

The following definition was changed for clarity due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Note 'b': Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.

Organization	Yes or No	Comments for Question 9
FRCC Transmission Working Group		Consider the following definition for clarification: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment.
Response: Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
ERCOT ISO	No	* Planning horizon is not formally defined but used many times throughout the standards. If there is a need to define the Near- and Long-term Transmission Planning Horizons, then the transmission planning horizon itself also should be defined. Additional confusion on this issue is the use of Long-term Planning as a planning horizon of one year or longer, also not formally defined. We finally found this referenced in the NERC Drafting Team guideline, which is not an obvious place to look for a definition. * Year One is only used two times " once to define Near-term Transmission Planning Horizon and once in the TPL standard. If this is not used throughout the NERC standards, it should not be defined. As an alternative, the transmission planning horizon could be formally defined, with Near- and Long-term Transmission Planning Horizons defined as subsets of the main definition. This would eliminate the need for a formal definition of Year One. If Year One stays as a new definition, it seems to be too broad, potentially allowing for omission of a peak season in the study. For example, if Year One is the period 12 to 18 months from the end of 2009, then Year One is currently 2011. Why is the year 2010 not considered to be Year One.*

Organization	Yes or No	Comments for Question 9
		Non-Consequential Load Loss is confusing " due to the base word "consequence". Consequential Load Loss is intended to be a load loss that is a result, or consequence, of the isolation. Non-Consequential Load Loss seems intended to imply it was not a consequence of the isolation. Although the standard attempts to define the term, this definition does not agree with the common English definition of the term. "Non-consequential" (or "Inconsequential") implies that the load loss is unimportant, minor or insignificant. This is the opposite intent of how this term is used in the standard, where it is used to mean the load that it is unacceptable to lose for a particular event. Alternatives could be "Direct Load loss" and "Indirect Load loss" to replace the two concepts that are included as Consequential and Non-Consequential respectively.
Response: Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. Year One: Year One is not considered to be the immediate year following the current year because if the study were completed at the end of the year, then there would be no time to implement a Corrective Action Plan. Also, that following year is in the Operational Planning time frame. No changes have been made. As you have indicated, the terms 'consequential' and 'non-sequential' can be interpreted consistent with the intent of the SDT. Further the use has been accepted by NERC and seems to have been accepted by the industry in the multiple postings to date. By changing 'Non-consequential' (or not-consequential) to 'inconsequential' you have changed the meaning. The SDT is content with the terms and has focused on the clarity of the definition, which also seems to be the focus of the comments from the industry. The SDT has decided to stay with the existing terms rather than changing them as this late date. No changes have been made.		
Northeast Utilities	No	[Comment on Year One Definition] This still defines Year One as both a particular year AND a window. It cannot be both. We suggest rewording the second sentence to read: "This is further defined as the beginning 12-18 months from the end of the current year".
Hydro-Québec TransEnergie (HQT)	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year."
Response: The SDT does not agree that there is an issue and has not changed the definition.		
Platte River Power Authority	No	1. Please make the definition for Non-Consequential Load Loss simple and straightforward. For example, Non-Consequential Load Loss: The planned shedding of firm load.(Note that phrases "firm load" and "firm load shedding" are used frequently in a dozen other standards.) 2. Move the remainder of the sentence about "the response of voltage sensitive Load including...by end-user equipment." from the Non-Consequential Load Loss definition to the Consequential Load Loss definition.
Response: Non-Consequential Load Loss; Due to comments received in earlier postings, the SDT believes that the definition can not be that simple. The SDT believes the exclusion of voltage sensitive load belongs in the Non-Consequential Load Loss definition because it is not Non-Consequential Load. Therefore, any reduction in load due to sensitivity to low voltage would not result in a compliance violation. No change made.		

Organization	Yes or No	Comments for Question 9
To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
NERC Standards Review Subcommittee	No	A. Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. The MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. B. The MRO NSRS offers the following comment to one of the proposed definitions of TPL-001. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss that is the result of the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. C. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet. D. The SDT is to be commended for working on the Year one definition, however, concerns exist that if the standard is adopted as written, it is incompatible with the eastern interconnection wide ERAG model process. E. If the SDT intends to change the planning processes and model building processes throughout NERC in this regard, then the SDT should explain the benefits of changing this process and verify that it does not sabotage the normal model building and study process.
Response: A. Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. B. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment C. The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made. D & E. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning		

Organization	Yes or No	Comments for Question 9
Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities.		
MAPP	No	Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
United Illuminating	No	As currently defined "Non-Consequential Load Loss" could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest clearly defining exactly what Non-Consequential Load Loss is as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."
Central Maine Power Company	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse; the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.We suggest defining Non-

Organization	Yes or No	Comments for Question 9
		Consequential Load Loss as “intended post-Contingency loss of load caused by operator or SPS (RAS) action.”
ISO New England	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequencetof the change in definition. This requires a change in the definition or the table.We suggest defining Non-Consequential Load Loss as “intended post-Contingency loss of load caused by operator or SPS (RAS) action.”
National Grid	No	As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse, the definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be unintended consequent of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as “intended post-Contingency loss of load caused by operator or SPS (RAS) action.”
Response: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF’s previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		

Organization	Yes or No	Comments for Question 9
Deseret Power	No	Comments: The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language follows Non-Interruptible Load loss other than: “Consequential Load Loss“ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment. This version uses the same wording but clarifies that the term “other than” applies to all three things.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Sacramento Municipal Utility District	No	Definition of Non-Consequential Load (Non-CLL): This definition excludes from the “Non-Consequential Load” only the “Interruptible” portion of Demand Response. The last SDT response to a comment on Draft #3 stated that there is no ceiling on the amount of DSM that can be utilitized (see Reference 1 below). Since Demand Response is more than just “Interruptible” demand, it is recommended that the exclusion in the definition for Non-CLL be broadened to include other relevant categories (see Reference 2 below) of Demand Response / DSM that is acceptable. Reference 1: pdf page 310, 337: SDT response related to DSM at http://www.nerc.com/docs/standards/sar/ATFNSDT_third_posting_comment_responses_2009Sept16.pdf Reference 2: http://www.nerc.com/docs/pc/drdtf/DADS_Phase_III_Final_090109.pdf, Figure 3 at pdf page 16, block under Capacity; and, associated definitions in Appendix III at pdf page 46 Use of the defined term “Planning Assessment” throughout the standard: Since the definition includes both performance evaluation (assessment) and corrective action to remedy identified deficiencies, its usage throughout the standard should be reviewed to ensure that it does not mandate corrective actions where the minimum requirement may be calling only for an assessment. The SDT should consider including a definition for “Spare Equipment Strategy”. The SDT’s comments on “spare equipment strategy” (at pdf page 122 of Consideration of Comments on 3rd Draft) state that it is based on a directive from FERC Order 693. Directives that impact reliability should be translated in to a requirement in a Standard. Even the proposed scope of MOD-010-0 (reference http://www.nerc.com/files/2010-2012_RS-Development-Plan_Volume-I_II.pdf page 223) makes a reference to the strategy, but does not require it.
Response: DSM: The SDT believes that any Load that is interruptible should be so under an agreement or tariff provision, which excludes it from the constraints of the TPL standard. No changes have been made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the ‘do nothing’ option, which would address the concern		

Organization	Yes or No	Comments for Question 9
and decided not to change the definition. Spare equipment strategy: The SDT believes that spare equipment strategy can be managed by individual Transmission Owners and that the term does not have to be defined in the Standard. The SDT further believes it has satisfied the intent of the directive of FERC Order 693 by including Requirement R2, part 2.1.5. No changes have been made.		
Midwest ISO	No	Definition Section: The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". Definition Section: We believe that the "Year One" definition changes have clarified what is intended. Definition Section: We suggest having the following definition of Consequential Generation Loss added to the definition section. Consequential Generation Loss - All generation that is no longer connected to the transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive, the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. No changes have been made. Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0.		
Northeast Power Coordinating Council--RSC	No	Definitions " Year One " This still defines Year One as both a particular year AND a window. It cannot be both. Suggest rewording the second sentence to read: "This is further defined as beginning 12-18 months from the end of the current year." As currently defined Non-Consequential Load Loss could allow widespread or cascading motor stall. The language in the definition cannot be this generic. The text is broad enough that it could allow a voltage collapse. The definition is incompatible with Table 1a (BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur). The definition for the non-consequential load loss combined with Table 1 would prohibit any customer from tripping its own load for contingencies that indicate 'no' in the non-consequential load loss column. This is not practical and appears to be an unintended consequence of the change in definition. This requires a change in the definition or the table.It is suggested to redefine Non-Consequential Load Loss as "intended post-Contingency loss of load caused by operator or SPS (RAS) action."

Organization	Yes or No	Comments for Question 9
Response: Year One: The SDT does not agree that there is an issue and has not changed the definition. No change made. Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. The proposed definition is too narrow and would only capture anticipated Load losses for predefined conditions. It would not capture unanticipated loss of Load, which still needs to be accounted for within the definition. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Gainesville Regional Utilities	No	I still find the Non-Consequential Load Loss definition vague. But, I presently do not have anything better to offer and thus I can live with it.
Response: Thank you for your response.		
SRC of ISO/RTO	No	In note b of the steady state and stability section of Table 1, consequential generation loss is referenced; however, there is no definition of such. A definition of consequential generation loss that is defined similar to "consequential load loss" should be added. The definition for "Bus Tie Breaker" should be revised to clarify whether a breaker in a standard ring bus or breaker and one-half scheme should be considered a "bus tie breaker". "year one" definition changes have clarified what is intended. AESO does not comment on VSLs or VRFs.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Bus Tie Breaker: The SDT has elected to define a Bus Tie Breaker. If the SDT were to also define what is not a Bus Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus Tie Breaker is to avoid further complexity.		

Organization	Yes or No	Comments for Question 9
The SDT does not see the difference between what is in the draft and what is proposed and does not agree that there is an issue. No change has been made to the definition.		
TVA System Planning	No	Is the 12-18 months referenced in the Year One definition actually from the start of the TA or the anticipated completion date of the same TA? Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss, (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment, and (3) utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads, etc when such loads do not result in tripping of a generating unit.
Response: Year One: Year One begins 12-18 months from the end of the calendar year. No change made. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT interpreted utility loads such as pump storage loads, compressed air generating pumping loads, and scrubber loads as interruptible loads, which don't need to be highlighted separately. As a result, no changes were made to include this list.		
NYISO	No	Question # 9 The SDT has revised the definitions in response to industry comments to the third posting. Do you agree with these definition changes? If not, please clearly indicate which definition you disagree with and provide specific comments. No. Need to define "Steady State" and "Consequential Load" as well as other phrases included throughout the NYISO's response.
Response: 'Steady State' was changed to 'steady state', so no definition is required. No change made. No instances of 'Consequential Load' were identified in the draft standard. All of the references were to 'Consequential Load Loss', which is defined. No change made.		
Oklahoma Gas & Electric	No	R 3.4, R3.5, R4.4 & R4.5 There appear to be no standards of directions on identifying severe or extreme system impacts. This may need to be defined. Extreme events evaluated (last page of Table 1) OG&E needs more specific information on what is defined to be an extreme event before offering support. It appears the number of possible combinations and permutations that could be run make any compressive study overwhelming to perform and would provide very limited benefits. This needs to be clarified.
Response: Extreme event: The SDT agrees that extreme event analysis could be overwhelming if all possible combinations and permutations were evaluated. However that is not the expectation. Requirement R3, part 3.5 of the standard requires only those extreme events "that are expected to produce more severe System Impacts". Therefore this is a judgment call with a corollary expectation that one can provide an explanation of the thoughts behind the judgment for selecting the events.		

Organization	Yes or No	Comments for Question 9
Duke Energy	No	Reword the definition of Non-Consequential Load Loss as follows: Non-Interruptible Load loss other than Consequential Load Loss and other than the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Florida Power and Light	No	The definition of "Known Commitments" should explain how that would differentiate between Planned Commitments Planning Assessment definition should be clarified as follows: Planning Assessment: Documented evaluation of (1) studies of future Transmission System performance and (2) Corrective Action Plans (included in studies) to remedy identified deficiencies. Non-Consequential Load Loss definition should be clarified as follows: Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, or (2) the response of voltage sensitive Load that is disconnected from the System by end-user equipment. The SDT should do a search through the document (and Table 1) on "cascading" and capitalize the "C" and delete "outages" where it appears after "Cascading".
Response: Known Commitments: The SDT believes that the existing language is adequate and no further change is required. If you do not have any known Firm Transmission Service as an example, then this fact should just be documented. Planning Assessment: The SDT considered the comment, but feels that a Corrective Action Plan includes the 'do nothing' option, which would address the concern and decided not to change the definition. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. The SDT did change, "cascading outages" to "Cascading" throughout the standard as suggested.		
Ameren	No	The definition of Bus-tie Breaker is unclear. This definition needs to be made clearer to remove issues regarding P2 and P5 planning events. We suggest the following additional language: A breaker in a standard breaker-and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest rewording Non-Consequential Load Loss definition: Non-Interruptible Load loss other than Consequential Load Loss. Non-Consequential Load Loss does not include the response of voltage sensitive

Organization	Yes or No	Comments for Question 9
		Load or Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Arizona Public Service Co.	No	The definition of Non-Consequential Load is confusing. It is not clear whether the response of voltage sensitive load and the load that is disconnected by the end user is included or not included. It is suggested that all items that are excluded be itemized and that there be no ambiguity.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Bonneville Power Administration	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load “ Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Idaho Power	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Modesto Irrigation District Transmission Planning	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load “ Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
NV Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user

Organization	Yes or No	Comments for Question 9
		equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Pacific Gas and Electric Co.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Puget Sound Energy, Inc.	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
San Diego Gas & Electric Co	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.
Southern California Edison (SCE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
SRP	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Utility System Efficiencies, Inc. (USE)	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Western Area Power Adm - RMR	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies.

Organization	Yes or No	Comments for Question 9
		Suggested revision to the language follows:Non-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
Xcel Energy	No	The definition of Non-Consequential Load is in need of clarification. As written, it could be interpreted that load that is disconnected from the System by end-user equipment would not be allowed for certain contingencies. Suggested revision to the language followsNon-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This version uses the same wording but clarifies that the term “other than” applies to all three things.
NorthWestern Energy	No	The definition of Non-Consequential Load needs clarification. A possible revision is to list bulleted items in the definition: Non-Interruptible Load loss other than: “ Consequential Load Loss “ the response of voltage sensitive Load ? Load that is disconnected from the System by end-user equipment.This way “other than” applies to all three bullets.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Omaha Public Power District	No	The definition of Non-Consequential Load Loss is not clear. It’s not clear whether “the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment” is considered to be Non-Consequential Load Loss or not. Based on previous drafts, it appears that the SDT’s intent is that “the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment” is considered to be a special type of Consequential Load Loss--a type that transmission-planning entities are not allowed to rely upon to meet steady-state performance requirements. Comments on this fourth draft from one commenter seemed to indicate that he was interpreting the definition of Non-Consequential Load Loss to mean that “the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment” is considered to be Non-Consequential Load Loss. Consider breaking the definition of Non-Consequential Load Loss into two or more sentences to prevent misinterpretation and confusion. Also consider including a reference to “the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment” in the definition of Consequential Load Loss if this type of load loss is considered to be a special type of Consequential Load Loss. If this type of load loss is considered to be a special type of Consequential Load Loss, add the following sentence to the end of Note “b” at the top of Table 1: However, see Note “i” for a restriction that applies to steady state performance.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

Organization	Yes or No	Comments for Question 9
The SDT believes the reference to exclude voltage sensitive load belongs in the Non-Consequential Load Loss definition because this is neither Consequential nor Non-Consequential. No change was made to Note 'b' or 'i' for this issue.		
NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should change the definition of Consequential Load Loss to clarify that load lost due to operation of remote backup protection is not Consequential Load Loss. Operation of remote backup protection is not Normal Clearing for a fault.Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by Normal Clearing initiated by the a Protection System operation designed to isolate the fault.
Response: Consequential Load Loss considering operation of remote backup protection: For the purpose of the Transmission Planning Standard the remote backup protection is still operating to isolate the fault and the SDT is interpreting the subsequent loss of Load to be Consequential Load Loss. No change was made.		
MidAmerican Energy Company	No	The SDT is to be commended for working on the Year One definition, however, MidAmerican continues to be concerned that if the standard is adopted with the Year One definition as written, it is incompatible with the eastern interconnection wide ERAG model process.The definition as currently provided in the draft standard states that Year One of analysis should begin 12-18 months from the end of the current calendar year. This contradicts the time frames that models are currently made available in the MRO as a result of the process for building models through the ERAG. For example, the models developed through the MRO and ERAG model building process in 2009 include cases for the years 2010, 2011, 2015, and 2020. According to the definition of Year One, the 2011 cases in the 2009 series models would be representative of Year One during the 2009 calendar year. However the ERAG models are not provided until late 2009, and some data sets may not be available until early 2010. With this Year One definition, there would be limited or no time where the ERAG model series would include cases representing Year One as defined in the draft standard. MidAmerican urges the SDT to delete the Year One definition altogether. Since the development of regional models are tied to ERAG models and since ERAG model timing is set at the interconnection-wide level, it is likely that nearly all Transmission Planners and Planning Coordinators are working with similar models that are available at similar times. It seems to MidAmerican that this detail on what Year One is can be easily controlled interconnection-wide through the ERAG and which models they provide when.However, if the SDT believes that the Year One definition is necessary, MidAmerican urges the SDT to revised the Year One definition from stating "12-18 months from the end of the current calendar year" to stating "0-18 months from the end of the current calendar year". This revised definition would be at least compatible with the current ERAG process.
Response: Year One: The SDT believes the definition will capture both a summer and winter peak and is necessary to provide a clear starting point for the planning horizon. With regards to any possible inconsistencies within the practices of any entity, the SDT believes that the requirements as defined are required for a Planning Assessment. How these requirements are met is beyond the scope of this standard and should be discussed within the responsible entities. No changes were made.		
Tri-State Generation and Transmission Association	No	The SDT removed definitions of Extreme Events and Load Reduction. We still need to have some scale to differentiate N-1 from less likely but possibly higher impact events. However, we do understand that such a

Organization	Yes or No	Comments for Question 9
		criteria will take some time to develop, and should perhaps be a separate subject addressed by a new SAR. Year One has a flexible definition. It does not seem very intuitive. We can't say whether this is good or bad, although one entity's year one could overlap with another's year two.
Response: The SDT doesn't see a problem with entities having slightly different study periods. This situation exists under the current TPL Standards.		
US Bureau of Reclamation	No	The term "Consequential Load Loss" and "Planning Assessment" contain the terms "Transmission System" and/or "Transmission Facilities". The terms "Transmission System and Transmission Facilities are not defined in the NERC Glossary of Terms. The terms should either be in lower case or a definition added. The Term "Non-Consequential Load Loss" refers to a "Non-Interruptible Load" loss which is other than Consequential Load Loss. There is no mention in the Consequential Load Loss definition of the type of load (interruptible or non-interruptible). This adds confusion to what appears to be the distinction in the differences between the two, that one was the result of a fault and the other was the result of voltage.
Response: Transmission system: The SDT was unable to find a reference to 'Transmission System'. The SDT believes the references to 'Transmission system' were used correctly and no change was made. Transmission Facility: 'Facility' is a defined term in the NERC Glossary. The SDT believes the references to 'Transmission Facilities' are used correctly and no change was made. Non- Interruptible Load: Consequential Load Loss can be either interruptible or Non-Interruptible, so the distinction is not required. Non-Consequential is not a concern if it is interrupting interruptible load, but is a concern if it is inappropriately interrupting Non-Interruptible load. So the definition for Non-Consequential Load Loss is specific to Non-Interruptible load. The SDT disagrees with your statement that the loss of Non-Consequential load is the result of voltage. Load Loss as a result of voltage sensitivity is excluded from Non-Consequential Load Loss by the definition. No changes have been made.		
American Transmission Company	No	We suggest the following changes: Add a Consequential Generation Loss definition, which would be a complement to the Consequential Load Loss definition. Both consequential load loss and consequential generation loss are referred to in note "b" of the Steady State & Stability section of Table 1, but only consequential load loss is defined. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Revise the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions."Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady

Organization	Yes or No	Comments for Question 9
		state and stability performance requirements set forth in the TPL-001 standard." Add a Planning Horizon definition. This term is used in this proposed standard, in the FAC-010-2 standard, and possibly in other future standards, but it has not been defined yet.
Response: Consequential Generation Loss: Generation run-back and tripping is acceptable. It is up to the Planning Coordinator and the Transmission Planner to determine how many units or cumulative MW may be interrupted due to either a consequential or non-consequential action. Therefore it isn't necessary for the SDT to define Consequential Generation Loss. Note 'b' has been revised to clarify the issue. Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. **Note 'b':** Consequential Load Loss as well as generation loss is acceptable as a consequence of any planning or extreme event excluding P0. Consequential Load Loss: The SDT disagrees with your proposed revision to the definition for Consequential Load Loss because it would provide for the use of an SPS or RAS to trip Consequential Load for an undefined 'abnormal condition', which is not an acceptable definition. No change is made. Applicability to BES: It is stated in the Purpose that the Standard applies to the BES. Therefore, the SDT doesn't see the need to have to repeat that throughout the document. Therefore no change is made. Planning Horizon: The only location where planning horizon didn't specify Near-Term or Long-Term was in the 'Purpose'. The SDT didn't feel that this reference needed to be specific or was sufficient to warrant a definition. No changes have been made.		
SERC Dynamics Review Subcommittee (DRS)	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify as follows: Add this sentence to the end of the definition: "A breaker in a standard breaker"and-a-half or ring bus configuration is not a Bus-tie Breaker. Suggest revising the Non-Consequential Load Loss definition to: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
SERC Planning Standards Subcommittee	No	With the simplified definition for Bus-tie Breaker, would a breaker in a standard ring bus or breaker-and-a-half scheme be considered a Bus-tie Breaker? Request the definition be revised to clarify this. Suggest revising the Non-Consequential Load Loss definition: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Bus-Tie Breaker: A breaker in a ring bus or a breaker-and-a half scheme would not be considered Bus-tie breakers. The SDT has elected to define a Bus-Tie Breaker. If the SDT were to also define what is not a Bus-Tie Breaker, then anything that was missed would not be defined. To be comprehensive the SDT has to limit the definition to what a Bus-Tie Breaker is to avoid further complexity. Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss.		

Organization	Yes or No	Comments for Question 9
Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
TIS	Yes	
Orlando Utilities Commission	Yes	I agree, but that is based on not having seen any proposed changes from others that might change my mind.
Lafayette Utilities System	Yes	LUS generally supports the changes to the definitions and the changes to the rest of the standard. We appreciate the efforts of the SDT in responding to the many comments that were filed in response to version 3, and in crafting what appears to LUS to be a reasonable attempt to attain a consensus position, at least as we understand the result.
ITC Holdings	Yes	None

Organization	Yes or No	Comments for Question 9
PJM	Yes	
Response: Thank you.		
Oncor Electric Delivery	Yes	(Motor stall should not be included in this section) The language in the definition cannot be this generic. This becomes open to interpretation in Table 1. Localized load may not be an issue, but the text is broad enough that it could allow a voltage collapse.
Response: Non-Consequential Load Loss: The SDT added Requirement R5 to require that every Transmission Planner and Planning Coordinator has a voltage criteria. The voltage criteria should prevent the exposure to widespread or cascading motor stall and should limit any potential misinterpretation that the Non-Consequential Load Loss would allow such events. Table 1a (BES Transmission voltage instability, Cascading, and uncontrolled islanding shall not occur) supports Requirement R5 and reinforces the point that the definition for Non-Consequential Load Loss should not be read so broadly as to allow for unacceptable events. The definition for the Non-Consequential Load Loss excludes end-user actions, which disconnect the Load from the system. So Table 1 does not apply to such Load. To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		
Southern Company	Yes	Suggest revising the Non-Consequential Load Loss definition for additional clarity to the following: Non-Interruptible Load loss other than (1) Consequential Load Loss and (2) the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.
Response: Non-Consequential Load Loss: To improve clarity, the SDT has revised the definition for Non-Consequential Load Loss. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.		

10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category.

Summary Consideration: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. Final edits failed to correctly show footnote renumbering needed for removal of the Draft 3 footnote 1 which was moved to Requirement R4. All references to the prior Draft 3 footnote 1 should have been removed in Draft 4 and the remaining footnote references as shown in Draft 3 should have been decremented by a value of one. In Draft 5, the SDT has corrected the footnote references and the changes made are summarized as follows:

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Header notes	Yes	For item "j" the footnote reference to footnote "1" is now removed.
Title Row, Planning Events	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P0	No	No footnote references are used in this row in Draft 4. No changes required in Draft 5.
Planning Event P1	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P2	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P3	Yes	Footnote references to "19" should have been "9".
Planning Event P4	Yes	In the column titled "Category" the footnote reference to "101" should have been "10". In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "10" should have been "9."
Planning Event P5	Yes	In the column titled "Interruption of Firm Transmission Service Allowed" the footnote reference to "19" should have been "9".
Planning Event P6	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Planning Event P7	No	All footnote references were shown correctly in Draft 4. No changes required in Draft 5.
Extreme Events Steady-State 2a & 2b	Yes	Footnote references to "12" should have been "11".

Table Area Reference	Footnote Reference Errors in Draft 4	Comment
Extreme Events Stability 2a, 2b, 2c, 2d	Yes	Footnote references to “11” should have been “10”.
Extreme Events Stability 2e	Yes	Footnote references to “11” should have been removed.

A number of commenters indicated that some planning events will result in the same elements being removed from service and sought clarification on whether or not each event required analysis. The SDT acknowledges that different initiating events may result in identical Facilities being removed by protection action. While there may be some overlap in the steady-state timeframe, care must be taken to ensure proper reviews are made in the Stability timeframe where warranted due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events “…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …” If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that “produce the more severe impacts” for their System. Planning event P2-1 was renamed to “Opening of a line section w/o a fault” to better clarify the SDT’s intended analysis. This was in response to some commenters who remained confused by the P2-1 event and felt a detailed breaker model may be necessary. The drafting team clarifies here that a detailed breaker model is not needed. Conforming changes were also made to footnote 7 to make clear the intent of this planning event.

The P5 Protection System Failure event description was changed in support of stakeholders who indicated that multiple element outages may not always result from a P5 event and that it may only result in Delayed Fault Clearing of the faulted Transmission element/Facility. The P5 event now states “Failure of a single Protection System that results in Delayed Fault Clearing on one of the following:”

Footnote 9 is now applied to all “No” items for the column “Interruption of Firm Transmission Service Allowed”. Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained.

Some commenters expressed confusion on whether or not an event is classified as an EHV or HV event. This is an important concept to understand as it directly relates to the stated Table 1 criteria for Interruption of Firm Transmission Service and Non-Consequential Load Loss. The event is classified as EHV or HV based on the lowest nominal system voltage level of all the Facilities removed by the event studied and regardless of the fault location. For example, a fault that removes a 345/138kV transformer is classified as a high-voltage (HV) event and the HV criteria apply. Changes to footnotes 1 and 5 were made to aid understanding in this regard.

Note changes are as follows:

Header note 'f': Applicable Facility Ratings shall not be exceeded.

Header note 'g': System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Footnote 1 - If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 2 - Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3 - Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.

Footnote 5 - For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

Footnote 7 - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

In addition, the definition of Non-Consequential Load Loss was revised to provide greater clarity:

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Organization	Yes or No	Comments for Question 10
FRCC Transmission Working Group		Please clearly indicate for P3 and P5 that note 1 and note 9 apply. Consider using a comma, not a note 19 that does not exist. The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the

Organization	Yes or No	Comments for Question 10
		breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has accepted the commenter's suggestion to better clarify the P2-1 planning event. The Event description in Table 1 for the P2-1 planning event has been re-titled "Opening of a line section w/o a Fault[7]" and the corresponding footnote number 7 has been revised to read as follows: **Footnote 7 -** Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.		
SRP	No	: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Northeast Utilities	No	[Comment on Non-Consequential Load Allowed for certain Planning Events] We recommend that the standard as written should not allow non-consequential load loss to be used to resolve violations arising from the planning events in Table 1. We believe that planning for a reliable power system should discourage mitigation by load loss. Therefore, Non-Consequential Load Loss should not be allowed in a future looking system plan.

Organization	Yes or No	Comments for Question 10
		[Comment on Table 1 Item e, under Steady State & Stability] Our understanding here is that we should be able to redispatch after the first contingency (using fast start generation) to secure the system in anticipation of a second contingency and not redispatch to fix first contingency violations. Is this interpretation correct?Further, this standard doesn't specify which units can be adjusted following the contingency. This seems to stress the fact that the standard needs to address the definition of what is a base case. Also, the standard should be clear on whether we can or cannot rely on generation redispatch after the first contingency, i.e., should the failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? [Comments on Footnotes] Footnotes 1, 10, 11, 19 and 101 need to be fixed. They are either mislabeled or do not point to any item.
Response: The SDT disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV Facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. The standard in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) indicates that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Therefore, the SDT does not agree with Northeast Utilities view in this regard. The standard does not include prescriptive expectations for a "base case" conditions and allows flexibility to the TP/PC in this regard. See requirement R1 for initial model (P0 starting conditions) requirements. Starting of a "fast-start" generation unit appears to be viewed in the context of a Corrective Action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
British Columbia Transmission Corp	No	1. Table 1 event indicates loss of one of the equipment. It appears to be silent on the event classification regarding multiple equipments within the same protection zone. Is this considered as a single contingency or multiple contingencies? Please clarify. 2. Table 1 P5 refers to the event on loss of multiple elements caused by the failure of a single protection system while clearing a fault on one contingency. For systems equipped with dual or redundant protections, is a protection failure still a valid concern? Shouldn't this contingency analysis be excluded from the requirement? Please clarify. 3. Table 1 Extreme Events under Stability section, there is a reference to protection failure during fault clearing. Again for systems equipped with dual or redundant protections the requirement should be reconsidered. Please confirm. 4. Table 1 Extreme Events under both Steady State and Stability sections, there is a reference to loss of transmission lines on a common right-of-way. Please consider adding a Footnote to define the common right-of-way using minimum length similar to the one used for circuits on common structure (Footnote 12).

Organization	Yes or No	Comments for Question 10
		5. Performance Table 1 Footnote Item 1 on definition of angular stability, it states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." o The requirement of no unit pull out of sync is not clear. Does this apply to small generators connected to distribution or lower voltage class lines? Or this is only applicable to generators connected to BEC (i.e. 100kV and above) without intermediary transmission voltage line connections? 6. Table 1 Footnote Item 6 refers to the "reference voltage" for transformers. What is the purpose of a reference voltage? Is this used to determine a valid transformer contingency? If so, according to the present definition a 3 phase fault on the 138kV side of a 138/66kV transformer is not considered a valid contingency to be assessed. Is this the intent?
Response: 1. The P1 Event is a single Contingency condition. A P1 Event may or may not remove other BES Facilities with it depending on the Protection System design. For example, a fault on a Transmission line (single Contingency) may also remove a BES transformer if no high-side transformer protection device is installed. 2. A P5 Event with a redundant Protection System will be covered by the analogous single Contingency event from a steady-state view. However, even with redundant Protection System designs there may be a delayed clearing mode that may need to be considered with the Stability timeframe. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. 3. See response to item 2. 4. The commenter appears to have referenced a Draft 3 version of the standard. The change requested was included in Draft 4. Footnote 11 in draft 4 reads as follows: "Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less". 5. The commenter appears to have referenced a Draft 3 version of the standard as the former Draft 3 footnote 1 was moved to Requirement R4, part 4.1.1 in draft 4. The applicability of the NERC Reliability Standards unless otherwise stated is the Bulk Electric System and Part 4.1.1 applies only to BES generating units. **6.** The commenter appears to have referenced a Draft 3 version of the standard and the question is related to footnote 5 of the Draft 4 standard. The term "reference voltage" is used in determining if a transformer is classified as EHV or HV for the BES. This classification then ties to footnote 1 in regards to provisions for the interruption of Firm Transmission Service and Non-Consequential Load Loss. For example, if a 345/138 kV TR is outaged for the Event studied, the high-voltage (HV) allowances for interruption of Firm Transmission Service and loss of Non-Consequential Load would apply. The 138/66 kV transformer may not be classified as a BES Facility, your Regional Entity definition of the BES should be consulted for an official position.		
NERC Standards Review Subcommittee	No	A. P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. The MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the

Organization	Yes or No	Comments for Question 10
		"generator + another element" events to the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. B. The SDT should be commended for the changes that were made to Table 1. However, the MRO NSRS does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. The MRO NSRS recommends that item d under the Steady State and Stability heading be deleted. C. Why is there a footnote 1 indicator to note j. under Stability only? The MRO NSRS suggests that this footnote 1 indicator be deleted. D. Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected from the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. The MRO NSRS suggests that Item i. under steady state only be deleted. E. The MRO NSRS does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but The MRO NSRS recommends that this be corrected.F. The MRO NSRS does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but The MRO NSRS recommends that this be corrected.

Response:

A. The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order regarding outage probability is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

B. The SDT appreciates the support for changes made. The SDT decided to keep both references to "simulate normal clearing unless otherwise specified". While redundant, we believe it is important information and should aid to ensure industry is aware of the intent.

C. The reference to footnote 1 in Table note "j" should have been deleted in Draft 4. The SDT has fixed a number of footnote reference errors in Draft 5.

D. The Draft 4 definition of Non-Consequential Load Loss confused some stakeholders in that some thought the voltage sensitive Load was "inclusive" to this type of Load. The definition was changed to better clarify the SDT's intent that customer sensitive Load and Load disconnected by the end-user is not included within the definition. With that change the perception of a conflict is now resolved.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

E. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Organization	Yes or No	Comments for Question 10
Bonneville Power Administration	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. Table 1, the second to last column: Please clarify what is meant by “Interruption of Firm Transmission Service.” Planning studies do not differentiate firm and non-firm transmission services. Planning studies model a load forecast, a generation dispatch, and the system topography. Interruption of firm transmission service is a commercial issue and is not related to assessing reliability of the system. If an assumed transfer is interrupted in a power flow case due to a contingency, and if no consequential load loss were allowed and all criteria were met, the system would still be exhibiting reliable performance. We believe interruption of firm transmission service should be allowed for all planning events P1 through P5 when assessing the reliability of the transmission system. At a minimum, footnote 9 in Table 1 should apply to all events in category’s P1 through P5 that do not allow interruption of firm transmission service.The NERC definition of Firm Transmission Service states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." Planning events required to be evaluated in Table 1 are unplanned interruptions by nature since they are studied to determine mitigation should they occur unexpectedly. This is inconsistent with the definition Table 1, P1.4, P3.4, P4.4, P5.4, and P6.3: Shunt devices are not required to be in service at all times. It does not make sense to include it in the events column. How would you assess it while several of these devices are not deployed because they are not needed for the conditions studied? Table 1, P1 & P2: What is the rational for having two categories for single contingency? Table 1, P2.1 (Opening of a breaker without a fault): Please clarify what constitutes opening a breaker without a fault mean? Planning for these events will be time consuming (modeling every breaker position open) and expensive to mitigate for events that occur solely due to human error and should be removed for the table. Table 1, P2.2, P2.3, and P2.4: These are not single contingency events and should be moved to P3.

Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events “…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …” If a Transmission

Organization	Yes or No	Comments for Question 10
Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agreed with the commenter regarding the Table 1 performance requirements related to the Interruption of Firm Transmission Service. The team has applied footnote 9 to all Events that indicated "No" in this column. The Firm Transmission Service within the context of a planning horizon are long-term service arrangements from one Balancing Authority area to another that should be reflected within the planning model and net-interchange. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events not pertinent for a given study then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. The two Contingency categories are used to delineate between higher ranked P1 single Contingencies and the lower ranked, yet high impact P2 single Contingency events. In P2, the team chose to differentiate between the EHV and HV in regards to performance expectations whereas in P1 the performance requirements for both EHV and HV are the same. The SDT believes the P2.1 event is important for review and it remains in Draft 5. Inadvertent relay operation that trips a breaker(s) is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. The P2.1 event has been renamed "opening of a line section w/o a fault" to better align with the team's intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads: **Footnote 7 -** Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point. The P2.2, P2.3, and P2.4 planning events are less likely yet higher impact single Contingency events. While its true that these events will likely result in multiple elements being disconnected from the System they are classified as single Contingency since they are a common mode event resulting from a single fault with normal Protection System clearing. As stated above, the SDT does not treat the P2 events in the same manner as P1 events and there are unique expectations in performance for P2 events that result in HV element outages versus solely EHV element outages.		
Idaho Power	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes

Organization	Yes or No	Comments for Question 10
		to ensure accuracy prior to balloting this standard.
Southern California Edison (SCE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Utility System Efficiencies, Inc. (USE)	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service. Simulations of these outages would then be the same, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced. I would encourage drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Western Area Power Adm - RMR	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. I believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any footnote in the document, and some other footnotes seem to be misplaced.I encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.

Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission

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Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Modesto Irrigation District Transmission Planning	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard. please define "post contingency" and "post transient" Why was the previous version footnote 1 defining "angular stability eliminated?
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. As an alternative, the SDT will ask WECC area SDT member(s) to discuss this matter via appropriate WECC technical committees utilizing SDT members as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT did not receive a substantial appeal from industry to define the terms proposed by the commenter and these terms are widely used and accepted in the industry. The proposed definitions were not added in Draft 5. The prior footnote 1 regarding angular stability was moved into the requirements section of the standard under Requirement R4 per the request of various		

Organization	Yes or No	Comments for Question 10
stakeholders in prior drafts.		
NV Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Pacific Gas and Electric Co.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Puget Sound Energy, Inc.	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document, and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
Deseret Power	No	Comments: As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. We believe that the drafting team needs to conduct a workshop prior to balloting to educate the industry on what outages are required to be simulated for which Categories. Additionally there are footnotes numbered 12, 19, and 101, which do not relate to any foot note in the document,

Organization	Yes or No	Comments for Question 10
		and some other footnotes seem to be misplaced. We encourage the drafting team to carefully review all footnotes to ensure accuracy prior to balloting this standard.
NorthWestern Energy	No	Several outages identified in Categories P2, P4, and P5 seem to result in the same elements being removed from service, even though the initiating event is different. Thus, the same scenario is evaluated more than once. Also, the footnote numbering is not correct. We would like the drafting team to conduct a workshop before this standard goes to ballot to educate the industry on what outages are required to be simulated for which Categories.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. At this time the SDT does not plan to conduct a workshop as suggested by the commenter. If Regional Entities wish to conduct seminars on the standard, SDT members from that region could be made available as participants in the discussions. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Sacramento Municipal Utility District	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different. Comments on notes have been provided with associated requirements.
San Diego Gas & Electric Co	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe		

Organization	Yes or No	Comments for Question 10
System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, PEF will have no further comment on this issue other than to encourage all appropriate parties to review PEF's previous comments to this effect.
Response: Throughout the drafting process, the SDT has carefully considered your comments as well as comments from other industry members.		
Pepco Holdings, Inc. - Affiliates PHI	No	Category P5 should be more appropriately titled DELAYED CLEARING OR Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following....A protection system failure does not necessarily lead to loss of multiple power system elements. Sometimes it may just be delayed clearing of the faulted element. The recommended change is based on the SDT's response to comments submitted to Draft #2 of the standard? -A number of commenters expressed concern related to Planning Event P5 "Protection System Failure" and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to "single component failure" and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. --The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.-- A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. Also, the phrase "failure of a single Protection System" should be defined. Draft #1 language used the term -single component failure- of a protection system. Based on a number of comments that were received, that term was subsequently replaced with the term -failure of a single Protection System-. To avoid confusion, this term needs to be defined within this standard and / or examples provided. If not, there will be confusion on how to study this category of events. This issue has been raised by numerous commenters throughout the standard development process. That fact that it continues to be expressed through numerous drafts indicates a lack of clarity as to exactly what protection system failures are to be studied.For example - Assume there are two protection systems on a facility (Scheme A and Scheme B). Assume one publishes a clearing time for Scheme A, and a slower clearing time for Scheme B. The TPL standard, as written, could imply that for a P5 failure of a single Protection System (scheme A or B fails) you would study the event assuming the worst case clearing time (i.e., using the slower clearing time for Scheme B.) Is that what is intended? If so, it should be so stated. However, that interpretation assumes the failure of a single Protection System would not effect the operation of the second Protection System. In other words it would not address single component points of failure, which could disable both Scheme A and Scheme B. Suppose both schemes were fed from the same set of CT's, VT's, battery, etc. Since the phrase "single component failure of the protection system" was eliminated, does this mean failure of both schemes due to a single component failure is not required to be studied under the P5 category? The standard must be very clear as to what contingency (i.e., what kind of protection system failure) is

Organization	Yes or No	Comments for Question 10
		to be studied. It should not be silent on this point, nor should it refer to another standard for guidance on what contingencies to study.
Response: The SDT agrees with points raised by the commenter and has changed the event description of the P5 planning event to better clarify the intent of simulating this Contingency. The SDT did not agree with the proposal to add a definition for the phrase “failure of a single Protection System”. The SDT believes the description modification in the Event column of Table 1 suffices in this regard. The P5 planning event remains unchanged in the study work intended by the SDT and the description modifications are aimed only at clarifying our intent. The SDT confirms that the intent of P5 is not to study the loss of both Scheme A and Scheme B for the example provided by the commenter and that the expectation would be the study of the slower clearing time scheme (Scheme B).		
Oklahoma Gas & Electric	No	Category P7 OG&E supports as long as footnote 11 is included. Category P6 is an N-2 situation. OG&E does not support the wholesale study of every N-2 combination of contingencies even though one is allowed for the interruption of firm transmission service and non-consequential load loss. Establishing and maintaining operating guides associated with every N-2 set of contingencies is oppressive and would provide limited value. OG&E understands the need for targeted N-2 contingency studies; such as breaker failure. Category P5 Need more specific description of “Protection System failure” before receiving OG&E’s support. Category P4 OG&E supports performing studies. OG&E also supports the differentiation between “DHV” and “HV”. OG&E does not support developing operating guides for every voltage or overload issue discovered. Category P3 OG&E is concerned about the value of P3. Information about the expected value of performing studies for the category is needed before receiving OG&E support. Category P2 OG&E supports even though there are a few minor issues. Category P1 OG&E supportsOG&E will need every bit of the 60 months time mentioned on page 3 under “Effective Date” to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective. Comments Stability AnalysisStability Analysis Recommend Planning Coordinator will be responsible for running the stability analysis to assure NERC compliance. The Planning Coordinator and Transmission Planner should work together to prepare the data.
Response: In P7, footnote 11 remains, thanks for your support. In P6 not every possible combination would be expected to be studied, especially for a Transmission Planner/Planning Coordinator covering a very large geographic footprint. The standard allows engineering judgment and flexibility to exclude certain Contingencies that may not be pertinent for the conditions studied. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events “…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …” If a Transmission Planner/Planning Coordinator can justify that certain events are not pertinent for a given study then at their discretion they may		

Organization	Yes or No	Comments for Question 10
elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System. Based on feedback from some commenters the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. Regarding the comments provided on P4. The SDT appreciates the commenter's support in regard to the bifurcated approach of performance expectations related to the BES. The SDT believes all performance deficiencies related to thermal ratings and voltage ratings require corrective actions and the standard provides the Transmission Planner/Planning Coordinator a wide range of alternatives, including but not limited to Operating Procedures. As stated above, the Contingencies studied are expected to be those that have the most severe impact on a particular Facility and not necessarily every possible scenario. The SDT's review of outage events associated with various System conditions revealed that the potential for a generating unit outage being coincident with a variety of other Contingency conditions requires close evaluation. Again, study of some your largest units in combination with other events may suffice to cover the "more severe" conditions for your System and flexibility is afforded to the Transmission Planner to ensure proper coverage without the needed to study each and every combination. We appreciate your support on planning event P1 & P2 expectations. Regarding the proposal for Stability to be covered by the Planning Coordinator. The standard in P7 requires the Transmission Planner and Planning Coordinator to determine and identify individual or joint responsibilities for performing required studies. The Transmission Planner may rely on work being preformed by its Planning Coordinator but each is responsible for showing auditable compliance for the TPL-001-1 study requirements including Stability.		
SERC Planning Standards Subcommittee	No	Comments: Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, and number 101 in the P4 cell in the Category column.
Southern Company	Yes	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column (should be 9), and number 101 in the P4 cell in the Category column (should be 10). In header note j, the reference to footnote 1 should be removed. In steady state extreme events 2a and 2b, the reference to footnote 12 should be to footnote 11. In stability extreme events 2a through 2e, the reference to footnote 11 should be to footnote 10.
Lafayette Utilities System	Yes	While LUS remains concerned as to the way in which what is now footnote 9 may be followed in operation in areas where there have been historic problems with the old "footnote b", we appreciate the clarifications that have been made, and recognize that this may be the best way to resolve an issue for the industry. Please note that there remains what appears to be a typographical error in Table 1, Category P3, under "Initial System Condition" in that the footnote reference is to footnote 19, which does not exist. The reference was to footnote 10 in v.3 and we assume that the correct reference here is to footnote 9, which used to be footnote 10.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT		

Organization	Yes or No	Comments for Question 10
has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
US Bureau of Reclamation	No	Consequential Load Loss was defined, however, consequential generator loss was not. It may be easier to define "consequential loss" and let it apply to either.
Response: The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1.		
Tri-State Generation and Transmission Association	No	Extreme Events detailed at the end of Table 1 should be itemized in the same way as for so-called “Planning Events” at the beginning of Table 1. Steady State Extreme Event 1 would be EP1, Dynamic Stability Extreme Event 1 would be ED1, etc. Also, please use the term Dynamic Stability, not just Stability, as explained above. It would be helpful if descriptions had unique identifiers, for example Dynamic Extreme Event 1 could be called N-1-1. For Dynamic Extreme Event 1, the phrase “With an initial condition” conflicts with the phrase “prior to System adjustments” at the end of the sentence. The term “initial condition” suggests a maintenance outage, or at least an outage that has sustained long enough for the system to have responded/adjusted. Footnote text does not line-up with the body text in the Extreme Event Table. It seems to us that a bus-tie breaker would have the same chance of failure as another breaker. Therefore differentiation is not needed in Table 1.
Response: The SDT recognizes a minority position to label the extreme events in a manner similar to the planning events for a short-hand notation. However, based on lack of a significant majority objection to the extreme event table layout the team determined no changes were needed in this regard. The SDT believes the references to Stability in the extreme events portion of the table are sufficient. No changes made. The SDT does not believe that a conflict exists for extreme event 1 in regards to “With an initial condition” and “prior to system adjustment”. No changes made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition, the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Omaha Public Power District	No	If “the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment” is considered to be a special type of Consequential Load Loss, add the following sentence to the end

Organization	Yes or No	Comments for Question 10
		of Note "b": However, see Note "i" for a restriction that applies to steady state performance. In Note "g", change "voltage limits" to "voltages". In Note "j", it appears that the reference to Footnote 1 is not needed. For Category P3, should the reference to Footnote 19 in the second column be a reference to Footnote 9? For Categories P3, P4, and P5, in the column labeled "Interruption of Firm Transmission Service Allowed", are the references to Footnotes 19 and 10 needed? For Category P4, should the reference to Footnote 101 in the first column be a reference to Footnote 10? For Category P4, should the reference to Footnote 11 in the third column be a reference to Footnote 10? In Items 2a and 2b of the "Steady State" subsection of the "Extreme Events" section, should the references to Footnote 12 be references to Footnote 11? In Footnote 1, change "loss of Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the first sentence of Footnote 2, change "Normal Clearing faults" to "Normal Clearing of faults". In the second sentence of Footnote 2, remove the comma following the word "types". In Footnote 3, change "Non-Consequential Load" to either "Non-Consequential loss of Load" or "Non-Consequential Load Loss". (The point here is that the adjective "Non-Consequential" applies to the word "loss" rather the word "Load".) In the second sentence of Footnote 5, change "generator Step Up" to "Generator Step Up" to be consistent with the rest of the footnote.

Response: Load removed by end-user action or voltage sensitive Load that trips while the Transmission Planner/Planning Coordinator transient voltage criteria is being met is NOT a special case on Consequential Load Loss. No changes made.

The SDT agrees with the proposed change to note "g" in Table 1.

Header note 'g': System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT agrees with the proposed wording change to footnote 1. The SDT also made other changes to footnote 1 for clarity and it now reads:

Footnote 1 - If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load

Organization	Yes or No	Comments for Question 10
Loss. The SDT agrees with the proposed wording change to footnote 2. **Footnote 2 -** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. The SDT agrees with the proposed wording change to footnote 3. The team also made other changes to footnote 3 for clarity and it now reads: **Footnote 3 -** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. The SDT agrees with the proposed wording change to footnote 5. Footnote 5 now indicates: **Footnote 5 -** For non-Generator Step Up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.		
TVA System Planning	No	In Header note j - the reference to footnote #1 should be removed. Are batteries included as part of Protection System for P5 events? P3 reference to footnote #19 under Initial System Condition and for Interruption of Firm Transmission Service Allowed should actually be footnote #9. P5 reference to footnote #19 for Interruption of Firm Transmission Service Allowed should actually be footnote #9. The reference to footnote #101 in the P4 category should actually be to #10. For Steady State notes under Extreme Events, events 2a and 2b should reference footnote #11 instead of #12. For Stability notes, event 2 should refer to footnote #10 instead of #11.In footnote #3, should there be an “or” before “as defined by the Regional Entity”?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a “single Protection System” scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5		

Organization	Yes or No	Comments for Question 10
planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only.		
Arizona Public Service Co.	No	Note a: It would be helpful if there was a clear understanding of what constitutes voltage instability for the purpose of this standard. Is TP expected to have its own criteria for voltage stability? Are the dynamic and angle stabilities intentionally excluded? P3 refers to foot note 19 but there is no foot note 19. P4 refers to foot note 11, but the foot note does not seem to be applicable. Foot notes in second to last column of the table are confusing.
Response: In Requirement R5 the Transmission Planner/Planning Coordinator is expected to have documented its criteria for transient voltage response. It is expected that this criteria would reflect what would be considered voltage instability. Related to the question on dynamic and angle stabilities, the standard provides a requirement for what is considered a stable System in Requirement R4, part 4.1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Lakeland Electric	No	Recommended the following changes to the HV definition:Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems, per the Regional Entity's BES criteria/definition.
Response: The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
Duke Energy	No	Reword Steady State Only: f. as follows: "Applicable Facility Ratings shall not be exceeded." P3 Initial System Conditions footnote should be 9, not 19. Also, P4 footnote should not be 101. Please check all footnote references.
Response: The SDT agrees with the proposed wording change to header note "f" and it now reads: **Header note 'f':** Applicable Facility Ratings shall not be exceeded. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		

Organization	Yes or No	Comments for Question 10
Ameren	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of number 19 at several locations in the Firm Transmission Service column, which should be changed to number 9, and numbers 11 and 101 in the P4 cell in the Category column that should be changed to 10. Table 1 - Steady State and Stability Performance - Planning Events, note c., and Table 1 - Steady State & Stability Performance - Extreme Events, note a. will need to be revised to address the restoration of facilities as described above in comments to Questions 3 and 5. A header is needed on the third page of Table 1 Steady State & Stability Performance. Table 1 Steady State and Stability Performance Extreme Events - Steady State: Superscripts on items 2a and 2b should be 11 rather than 12. Similarly, for the Extreme Events - Stability items 2a through 2f, the superscript should be 10 rather than 11.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. As stated in the SDT's response to comments made by Ameren in Question 3, in Requirement R3, part 3.3.1 the reference to "other automatic controls" is intended to include other tripping means such as cross-tripping and not automatic restoration devices. No change made. Ameren comments to Question 5 do not appear pertinent to "automatic restoration" of facilities. No change made. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5.		
SERC Dynamics Review Subcommittee (DRS)	No	Some of the footnote superscripts do not appear to have a corresponding reference in the footnotes, in the case of: Table 1 Planning Events P3 superscripts should be 9 and not 19. Table 1 P5 superscript 19 should also be 9. Table 1 Planning Events P4 superscript 101 should be 10, superscript 11 should also be 10. Table 1 Extreme Events steady state items 2A and 2B superscript should be 11, not 12. Table 1 Extreme Events stability items 2A-2F superscript should be 10, not 11. No header on third page of Table 1 Planning Events. Table 1, Planning Events, wherever it says "no" in the "interruptions of firm transmission service" column, generation tripping by fault clearing action should be allowed.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees that an appropriate page header is needed on for each page of the Table and has worked with NERC staff to correct this in Draft 5. The SDT agrees with the commenter regarding the suggestion to permit generation re-dispatch when a "No" is indicated in the Table 1 column titled "Interruption of		

Organization	Yes or No	Comments for Question 10
Firm Transmission Service Allowed" and footnote 9 is now reflected on each occurrence.		
SRC of ISO/RTO	No	Table 1 should appear right after the requirements and before the VSLs. AESO does not comment on VSLs or VRFs.
Response: The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
ERCOT ISO	No	The references to the footnotes need commas there are several references to footnote 19 and at least one to footnote 101.
Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
MidAmerican Energy Company	No	The SDT should be commended for the changes that were made to Table 1. However, MidAmerican does recommend a few editorial changes. On page 16 under the Steady State and Stability heading is item d. Simulate Normal Clearing unless otherwise specified. This is also listed as footnote 2 to the table. MidAmerican recommends that item d under the Steady State and Stability heading be deleted. Why is there a footnote 1 indicator to note j. under Stability only? MidAmerican suggests that this footnote 1 indicator be deleted.? Item i. under Steady State only states that "the response of voltage sensitive Load that is disconnected form the System by end-user equipment" is not to be used to meet steady state requirements. However, the non-consequential load loss says yes meaning it is allowed for some events in the table and non-consequential load loss definition includes the "response of voltage sensitive Load that is disconnected from the System by end-user equipment." This seems to be a direct contradiction. MidAmerican suggest that Item i. under steady state only be deleted. MidAmerican does not understand why there is a footnote 19 indicator for P3 and P5 EHV in the table when no footnote 19 exists. Perhaps the SDT meant footnotes 1 and 9 but MidAmerican recommends that this be corrected. MidAmerican does not understand why there is a footnote 12 indicator for Item 2 a and 2 b. on page 19. Perhaps the SDT meant footnotes 1 and 2 apply but MidAmerican recommends that this be corrected.
Response: While the SDT agrees that the phrase appears twice, it does not create any confusion or unnecessary redundancy. Footnote 2 is just a more detailed explanation of what needs to be done in Stability studies. No change made. The footnote 1 indication has been deleted as suggested.		

Organization	Yes or No	Comments for Question 10
The definition of Non-Consequential Load Loss has been revised to provide greater clarity as to the SDT's intent. **Non-Consequential Load Loss:** Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.		
Xcel Energy	No	There are references to footnote 12 on page 19, and footnote 101 on page 17, yet no such footnotes exist on page 20. Some of the other footnotes seem to be misplaced. Please review and validate all footnote references.
Midwest ISO	No	Table 1 Steady State & Stability Performance Planning Events, Note "b": It states that consequential generation loss is acceptable; however, there is no definition of this in the definition section. We suggest having the following definition of Consequential Generation Loss added to the definition section. Table 1 There appears to be a few typos on P3, P4 and P5 note references because there are no Note 19 nor Note 101. Please clarify this. Table 1 Steady State & Stability Performance Planning Events: We believe that this table should appear right after the requirements but before the VSLs.
Response: It appears the commenter intended to suggest a definition for consequential generation loss but neglected to include its proposed definition. Regardless, the SDT considered the need for such a definition and concluded no definition was needed. No change made. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT agrees with the commenter's recommendation to move Table 1 within the standard so that it follows directly after the requirements. This change was made in Draft 5.		
Florida Municipal Power Agency, and its Member Cities	No	Table 1, under Steady State & Stability, "a" states: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur." There are small portions of the grid where there may be three long lines feeding a load, and if two of those two lines were lost (P6 for instance), the remaining line would go into voltage collapse losing a few hundred MWs of consequential load with no impact to the BES. FMPA suggests that the wording be appended by: "BES Transmission voltage instability, cascading outages and uncontrolled islanding shall not occur for P0 through P2. BES Transmission voltage instability, cascading outages and uncontrolled islanding causing a supply / demand mismatch of more than the largest single loss of source shall not occur." FMPA does not understand why a bus-tie breaker would be treated differently than another breaker. They both have the same chance of failure.
Response: The SDT considered the proposed change to note "a" but did not accept the proposed change. For the situation described, System adjustments are permitted between the outages of a P6 event to minimize the impact. Additionally, following the second outage the use of an SPS could be used to further minimize		

Organization	Yes or No	Comments for Question 10
the impact and avoid an unstable System condition. The team agrees that any breaker has an equal chance for failure due to a fault. However, when lumped together with all the BES line breakers and transformer breakers, the Bus-tie Breaker application is much less prevalent within the BES when considering all beaker fault possibilities. The SDT recognizes that Bus-tie Breaker applications are used to lessen the impact of a bus fault outage (P2.2). Therefore, in regards to meeting the single Contingency breaker fault condition the SDT felt it was necessary to differentiate between performance expectations between bus-tie and non bus-tie breakers. See P2.3 and P2.4 planning events.		
Manitoba Hydro	No	Table 1:1. When two (or more) footnotes apply simultaneously they should be separated by commas; ot are these typos? 2. The P2 contingency "opening of a breaker without a fault" could be moved up to a P1 contingency. This is a higher probability event then a bus section fault. 3. P4, Event column: The 11 superscript, after the phrase "Loss of multiple elements....", should be a 10. In P3, should 19 be 9? 4. Footnote 9: The drafting team clearly permits generator redispatch coupled with curtailment of firm transmission service for multiple contingencies (P3-P5). We believe generator redispatch is appropriate for P1 and P2 as well. R2.7.1 lists several actions that are permitted to be used as corrective plans including Special Protection Systems, automatic generator tripping or manual generator runback to respond to both single and multiple contingencies. Any loss of generation will require redispatch to ensure emergency generation reserves are replenished and the system is ready for the next contingency. For contingency P1, loss of generator, load will not be lost because there are generation reserves, however redispatch will be required to restore these reserves. Footnote 9 should apply to P1 and P2 contingencies. 5. Footnote 11: This note is a reference for a common tower outage. I think the words "or common Right-of-Way" should be deleted from the sentence. It is obvious that circuits on a common tower must be on a common Right-of-Way. 6. Note b: Consequential generation loss could use a definition similar to consequential and non-consequential load loss to add clarity. The standard as written in R4.1.2 permits cascade tripping of generators due to pulling out of synchronism. Typically this has been defined as instability or cascade tripping and not permitted in the past. 7. Note i: note i implies that any voltage sensitive load or load dropped by end-user equipment shall not be used to meet steady-state performance requirements. However, given that this note is not included under the stability portion, does this mean that voltage sensitive load or load that is dropped by end-user equipment can be used to meet the TC and PC planning criteria established in R5? Induction motors could trip in the stability analysis if the transient voltage is low enough (non-consequential load loss). The R5 criteria will be met as long as the load is manually switched back in and the post-disturbance steady state loading is acceptable. Can the drafting team

Organization	Yes or No	Comments for Question 10
		clarify the intent of Note i?
Response: 1. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. 2. The SDT did not accept the proposed change for the placement of the P2.1 planning event into the P1 group. 3. As noted above, errors in reference to various Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. 4. The SDT agreed with the commenter and footnote 9 was added to the P1 and P2 events in regard to the column titled "Interruption of Firm Transmission Service Allowed" 5. Common structure may be interpreted as common ROW but Common ROW does not necessarily equate to common structure. Since the wording is 'or', it covers both circumstances. No change made. 6. The SDT does not believe a definition to differentiate between consequential or non-consequential generation loss is needed since generation tripping and re-dispatch is permitted as a corrective action for all planning events as stated in Requirement R2, part 2.7.1. 7. Table 1, note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.		
NERC System Protection and Control Subcommittee (SPCS)	No	The Drafting Team should modify the P5 Category column in Table 1 to read "P5 Multiple Contingency (Fault plus Protection System failure to operate). "This addition will focus the P5 Category on the overall Protection System failure to operate." The Drafting Team should include requirements in P5 of Table 1 for simulating both single-phase and 3-phase fault types for Protection System failures to operate.P4 and P5 call for simulations with SLG faults. Prolonged clearing times that result from breaker failures or Protection System failures to operate increase the probability that the fault may evolve from single-phase to multi-phase, and that probability further increases in EHV substations due to the closer clearances of bus work and equipment.Whereas Breaker Failure times are more likely to be known and mitigated through Breaker Failure Protection Systems, the clearing times associated with Protection System failures to operate may be much longer, increasing the probability of evolving in to multi-phase faults. The phrase "or a protection system failure" should be removed from items 2a through 2e in the Extreme Event table following Table 1.If the initializing event is the SLG fault, its evolution to a multi-phase fault alone (due to a Protection System failure to operate) should not be considered an Extreme Event for stability analysis.
Response: While the SDT did not accept the proposed P5 description change a change has been made for clarity. Based on feedback from some commenters the		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Comments for Question 10</th></tr>
<tr><td colspan="3">SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent, and are aimed at clarification only.

In regards to include both a SLG and 3-phase for the P5 planning event the SDT respectfully disagrees with the commenter. Based on the SDT's review of historical outage data the SDT believes that a SLG event evolving to a 3-phase item is less likely and that 3-phase fault with Protection System failure is appropriately treated with the standard as an extreme event under extreme event Stability item 2a through 2d. No change made.</td></tr>
<tr><td>Florida Power and Light</td><td>No</td><td>The P2-1 event needs to be clarified with its intent. In the SDT Consideration of Comments to the 3rd DRAFT posting, the response to Transmission Planning clarified that "There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line." This could be accomplished by adding this to footnote 7 or re-naming the event "Opening of a Line Section w/o fault".</td></tr>
<tr><td colspan="3">Response: The SDT agrees with comments in regard to the P2-1 planning event. A relay mis-operation that inadvertently trips a breaker is the primary reason forced outage cause for a P2.1 event. The condition could also be a planned (maintenance) event. P2.1 has been renamed "opening of a line section w/o a fault" to better align with the teams intent. Additionally, footnote 7 was revised to better clarify the need to study the P2.1 event. Footnote 7 now reads:

Footnote 7 - Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.</td></tr>
<tr><td>MAPP</td><td>No</td><td>The table needs to match the stated requirements in R3 & R4</td></tr>
<tr><td colspan="3">Response: The standard explicitly references Table 1 in both Requirements R3 and R4 regarding the need to address the planning events and extreme events from both a steady-state (Requirement R3) and stability (Requirement R4) timeframe. The standard is written in a manner where both the standard requirements and Table 1 work jointly together to describe study expectations. In short, Table 1 is part and parcel to the standard.</td></tr>
<tr><td>Hydro-Québec TransEnergie (HQT)</td><td>No</td><td>There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?

Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well.

If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used.

Extreme Events 2a need to define towerline. Add language to replace towerline with structure.

Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the</td></tr>
</table>

Organization	Yes or No	Comments for Question 10
		wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases.Table 1 Steady State & Stability Performance Extreme Events It appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase "are the fault types, that must be evaluated." Please remove said comma. Table 1, footnote #3, HQT, as does NPCC, has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV", is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition "all Facilities greater than 300 kV" :"Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System. Furthermore, HQT believe that untill the BES/BPS definition debate is settled at NERC and FERC level, the proposed definition permits the use of the performance base methodology to determine the BPS element subjected to this standard. The way the standard is actually

Organization	Yes or No	Comments for Question 10
		written, it can be interpreted as 300 kV and above, wheter it is part of BPS or not. HQT believe it is overly prescriptive and leaves no leeway.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events.

The SDT believes that towerline is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in Requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used.

Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the Transmission Planner/Planning Coordinator regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review.

As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5.

The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event. Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The P5 is now described as shown below. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only.

Organization	Yes or No	Comments for Question 10
The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the same tower line or structure. Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
National Grid	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Table 1, P5: The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table		

Organization	Yes or No	Comments for Question 10
reference area for extreme events. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The SDT disagrees with the commenter that the P5 event is a misuse of the defined Protection System term. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity is not necessary. Other changes have been made to footnote for clarity based on other comments. **Footnote 3 -** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
Northeast Power Coordinating Council--RSC	No	There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading? Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. Extreme Events 2a need to define towerline. Add language to replace towerline with structure. Table 1 Footnotes require a close editorial review. There are two number ones, and multiple items pointing to the wrong footnote or footnotes that don't exist (19, 101), etc. Several instances are discussed below but this is not an exhaustive list. Table 1 Steady State & Stability Performance Planning Events - Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability. NPCC suggests this note be relocated to "Stability Only." Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in

Organization	Yes or No	Comments for Question 10
		place to trip end-user equipment. Table 1, P4 footnote reference in Category column needs to change from 101 to 10. Footnote reference in Event column lead-in description needs to change from 11 to 10. Table 1, P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. The use of the term “Protection System” in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Battery systems should not be included. Table 1, P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phases. Table 1 Steady State & Stability Performance Extreme EventsIt appears that for Steady state, item 2, that item (a) is encompassed by (b). It if is not, what makes it different? Table 1, footnote #2 typo there is an erroneous comma in the phrase “are the fault types, that must be evaluated.” Please remove said comma. Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed.More stringent performance requirements should be applied to Facilities that represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers, rather than to those Facilities that directly serve end-use Load customers. However, as had been commented in preceding postings, the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as “all Facilities greater than 300 kV”, is not appropriately defined and should be reviewed. A uniform voltage-level threshold has not been shown to adequately cover all of the different power systems in North America, and significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.The following is a proposed modification to the EHV definition “all Facilities greater than 300 kV”?: “Facilities representing the backbone of the System, generally operating at voltages greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity.” In using such language, we believe that the extra investment required would go towards real improvement of the reliability of the Interconnected System.

Response: The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT’s intent and it now reads:

> **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected

Organization	Yes or No	Comments for Question 10
the footnote references and a detailed explanation of the changes required are summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The SDT disagrees with the commenter's view that Table 1 note "a" is not valid for the steady-state timeframe. The standard in requirement R6 requires a Transmission Planner/Planning Coordinator to define and document, within their Planning Assessment, any criteria or methodology used in the analysis to identify System instability for conditions such as Cascading outages, voltage instability, or uncontrolled islanding. A steady-state review is not prohibited by the standard and may be included within the criteria used. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. As noted above, errors in reference to Table 1 footnotes are recognized by the SDT and have been corrected in Draft 5. The P5 event is not a review of individual Protection System components but rather evaluates the loss of a "single Protection System" scheme or design. It is acceptable to simulate that a local (at the same substation) alternate Protection System scheme is still operational when performing a P5 review. The SDT chose this language to align with the SAR titled: Reliability of Protection Systems (Project 2009-7). The SDT believes that the individual component level evaluation of Protection Systems and redundancy requirements should be covered under the PRC standards and has only addressed a single protection scheme failure in the Planning Assessment required for the TPL standard. A Protection System component failure (i.e., battery) that removes multiple Protection System schemes is beyond the P5 planning event Based on feedback from some commenters, the SDT made changes to the P5 planning event description as shown in Table 1. The changes are not substantive, do not alter the team's prior intent and aimed at clarification only. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No changes made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the <u>same tower line or structure.</u> Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The erroneous comma in footnote 2 has been removed as suggested by the commenter. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No change made.		
ISO New England	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well.

Organization	Yes or No	Comments for Question 10
		If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading"P5 "The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
United Illuminating	No	We generally agree with the table however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3, change Regional Entity to Regional Reliability Organization.
Central Maine Power Company	No	We generally agree with the table, however our issues are as follows:Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. Other footnotes appear to be mislabeled as well. If Extreme Events are not deleted from the standard, then a different number for the table for Extreme Events should be used. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV

Organization	Yes or No	Comments for Question 10
		autotransformer, are you allowed to shed load to keep the 345-kV from overloading? Conversely, if the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from overloading?P5 The use of the term "Protection System" in P5 is unacceptably inconsistent with the NERC definition of Protection System because it does not exclude the battery and its associated series elements. Extreme Events 2a need to define tower line. Add language to replace "tower line" with "structure". Table 1, footnote #3 change Regional Entity to Regional Reliability Organization.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has retained extreme events and believe it is important to review the extreme events for potential Cascading and if identified complete an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the extreme event(s). The SDT retained the same table reference area for extreme events The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT concluded that the use of Regional Entity in footnote 3 is not necessary. No change made to reflect the proposed Regional Reliability Organization as proposed by the commenter**.** **Footnote 3 -** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.		
American Transmission Company	No	We suggest the following changes:Note "e" in the Planning Events, Steady State & Stability section – After bulletin item #7 is added to R2.7.1 as proposed above, refer to this bulletin item with wording like, ". . . applicable to the Facility Ratings (as noted in R2.7.1).". Note "a" and Note "b" in the Planning Events, Steady State Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb "shall"), but all requirements should be included in the Requirements section and not introduced (hidden) in the performance notes of Table 1. After R3.3.5 is added as proposed above, replace Note "a" and "b" with wording from R3.3.5, "Applicable System

Organization	Yes or No	Comments for Question 10
		Operating Limits for the planning horizon shall not be exceeded, as stated in R3.3.5.”. Note “a” and “b” can be combined and replaced with a single Note because the observance of System Operating Limits related to steady state conditions covers both items. Note “d” in the Planning Events, Steady State Only section This note is stated in the form of a Requirement (e.g. use the verb “shall”), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R3.3.6 is added as proposed above, replace Note “d” with wording from R3.3.6, The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to steady state voltage requirements, as stated in R3.3.6. Note “a” and Note “b” in the Planning Events, Stability Only section Both of these notes are stated in the form of a Requirement (e.g. use the verb “shall”), but all requirements should be included in the Requirements section and not introduced in the performance notes of Table 1. After R4.3.5 is added as proposed above, replace Note “a” and “b” with wording from R4.3.5, “Applicable System Operating Limits for the planning horizon shall not be exceeded, as stated in R4.3.5.”. Note “a” and “b” can be combined and replaced with a single Note because the observance of System Operating Limits related to stability covers both items P3 Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. Move the “generator + another element” events to the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common tower.” Item 3.b of the Extreme Events, Steady State section “ Clarify the reference to actual, historical operating experience in Item 3.b. We suggest this text: “b. Other events based upon actual operating experience that may result in wide area disturbances.” Item 2.i of the Extreme Events, Stability State section “ Clarify the reference to actual, historical operating experience in Item 2.i. We suggest this text that is similar to Steady State, Item 3.b: “i. Other events based upon actual operating experience that may result in wide area disturbances.” Extreme Event sections are not updated to reflect the new footnote numbering (for instance Item 2a and Item 2b of the Steady State column). Footnote 6 “ Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements

Organization	Yes or No	Comments for Question 10
		which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.”

Response: The SDT in ATC’s Q2 comments declined to add the suggested 7th bullet to Requirement R2, part 2.7.1. The list in Requirement R2, part 2.7.1 provides examples of potential corrective actions and includes references to the use of generation tripping/runback when used to meet steady-state or Stability performance requirements. The note “e” in Table 1 is a condition for allowance of planned System adjustments, which could include Operating Plans such as re-dispatch and qualifies that the operating actions must be achievable with the timeframe of an applicable ratings. No change made.

The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. For example in Requirement R3, part 3.1 the requirement indicates “Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1..”. Header notes are part of Table 1 and therefore included in part 3.1 of requirement R3. No change made.

The proposed Requirement R3, part 3.3.5 was not adopted by the SDT. No change made.

Regarding note “d” comment - the Table 1 performance requirements are tied to the standard through Requirements R3 and R4.

The proposed Requirement R3, part 3.3.6 was not adopted by the SDT. No change made.

There are no notes “a” and “b” in the Stability only section. The correct reference is “j” and “k”. The Table 1 performance requirements are tied to the standard through Requirements R3 and R4. No change made.

The SDT disagrees with the proposed adjustment of moving select generator Contingency outages to new planning event designations. The Table 1 planning event order is somewhat subjective and the SDT believes appropriate expectations were made for generation outages within the P3 event. No changes made.

Item 2.a in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It’s possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 3b in the Extreme Events, steady-state the language as shown in Draft 4 already indicates the text requested by the commenter. It’s possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Item 2i in the Extreme Events, Stability language was revised to “2f” in Draft 4 and already indicates the text requested by the commenter. It’s possible that an earlier draft of TPL-001-1 was referenced when making the comment. No change required.

Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10.

Regarding footnote 6, the SDT believes the footnote is sufficient. Based on lack of support for the proposed change from other stakeholders the SDT determined no change was needed.

Organization	Yes or No	Comments for Question 10
Oncor Electric Delivery	Yes	Errata Changes - Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. Other Footnotes appear to be mislabeled as well. There is lack of clarity in the interpretation of Table 1 When the voltages class of the contingency element and the monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied. For example if the fault is on the 138-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 345-kV from exceeding its load rating? Conversely, if

Organization	Yes or No	Comments for Question 10
		the fault is on the 345-kV side of a 345/138-kV autotransformer, are you allowed to shed load to keep the 138-kV from exceeding its load rating? Table I, item "e" ?It doesn't specify which units can be adjusted following the contingency. This seems to be similar to the fact that the standard doesn't address the base case. Should the standard be clear that you can or cannot rely on generation redispatch? Should failure of a fast start generator to start up be included in the contingency, or is this another level of contingency? Table I, non-consequential load loss under no circumstance is it acceptable to shed non-consequential load to address issues in a future looking system plan. Table 1 Steady State & Stability Performance Planning Events - Note (i) this indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user UVLS scheme and possible contractual arrangement already in place to trip end-user equipment. Table 1, P7 for the DCT, are these the same phase? Table 1 Steady State & Stability Performance Extreme EventsSteady state, item 2, isn't (a) covered by (b) Table 1, footnote #3, NPCC has asked NERC to put a lower bound on the HV but it seems that this remains unaddressed. P5 This test is overly severe since it could assume the total protection system failure and the system would have to rely on remote end clearing. Part of the problem seems to be that the battery is part of the protection system. The intent seems to have been to fail part of one system, not the battery. If the battery is to be excluded, then it should be clearly stated. Extreme Events 2a The term "towerline" should be defined. We agree with the SDT that more stringent performance requirements be applied for the Facilities that do not directly serve end-use load but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant, additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following " Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the additional investment required would facilitate real improvement of the reliability of the interconnected System.

Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT

Organization	Yes or No	Comments for Question 10
has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. Regarding the note "e" reference to re-dispatch. The re-dispatch of any generation permissible for re-dispatch having impact on the Transmission Planner/Planning Coordinator area. The SDT believes that the standard is clear in Requirement R2, sub-part 2.7.1 (Corrective Action Plans) that generation curtailment, tripping and re-dispatch are permissible Corrective Action Plans for both single and multiple Contingency events. Starting of a "fast-start" generation unit appears to be viewed in the context of a corrective action solution to a studied planning event. There may situations like this that lend themselves to sensitivity analysis as required by the TPL-001-1 standard. The SDT respectfully disagrees with the commenter's view related to disallowing Non-Consequential Load Loss for any planning event. The SDT believes they have made the appropriate expectations in not permitting its use for some Contingency planning events involving EHV facilities. A Transmission Planner/Planning Coordinator may implement a more conservative planning approach beyond what TPL-001-1 requires if they believe one is warranted. Table 1 note "i" is intended to clarify that even if it is known that an end-user who implements a more conservative practice than that of the TP/PC regarding steady-state voltage criteria and chooses to interrupt its own Load, the end-use Load must still be represented in the steady-state timeframe. The Load tripping is permitted in a Stability review, however, it should be assumed that a customer will react quickly to restore its Load and therefore the standard requires the Load be represented in the steady-state timeframe. Only actions (manual or automatic) taken by the Transmission Planner/Planning Coordinator are permitted for consideration for a steady-state review. Interruptible Load agreements are permissible and the Load dropped through contractual arrangements with the end-user can be reflected in the steady-state analysis. The standard does not specify common or different phase for the P7 planning event and is left to the engineering judgment of the Transmission Planner/Planning Coordinator. No change made. Extreme event 2a does not cover 2b when two or more tower lines are contained in the same Right-of-Way. Extreme event item "2a" is 3 or more circuits on the same tower line or structure. Extreme event item "2b" considers loss of multiple Transmission lines located on a different tower line but within the same the same Right-of-Way. The SDT believes that tower line is a commonly understood term and that the use of "structure" over "tower line" is not a substantive change. No change made in Draft 5 in this regard. The SDT has retained the same delineation of the Bulk Electric System (EHV and HV) in Draft 5. No changes made.		
TIS	Yes	Footnotes on P3 and P4 (101 & 19) should be 9 and 10, respectively. This merely appears to be a typo in the latest draft. There is confusion in interpretation of the Table 1 When the voltages class of the contingency element and the

Organization	Yes or No	Comments for Question 10
		monitored element are different (one is HV and the other is EHV), to which voltage class is the allowance for shedding of non-consequential load applied?. Please see additional comments provided for R2.
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The determination of when interrupting Non-Consequential Load and/or Firm Transmission Service is permitted to meet Table 1 performance requirements service is based solely on the lowest voltage level of Facilities disconnected by design for the planning event studied and not based on the monitored Facilities. For the example provided, the HV provisions would apply since a 345/138kV transformer is considered a HV Facility that is removed from service regardless of where the fault originated. Changes were made to footnote 1 to better clarify the SDT's intent and it now reads: **Footnote 1 -** If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss. See the SDT's response to your comments provided for Requirement R2.		
Platte River Power Authority	Yes	If clarity is given for the "Non-Consequential Load Loss Allowed" column of Yes/No that it refers to the planned shedding of firm load. (see my comment on Definition)
Response: See the SDT's response to your comment in Q9.		
American Electric Power	Yes	In Table 1, footnotes 19 and 101 should probably read 9 and 10. Also, we suggest adding table borders in P4 to more clearly align the columns that correspond to Event 6 (similar use of table borders as was done in P2).
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. The SDT has made changes to the table borders for the P4 planning event per your recommendation.		
Orlando Utilities Commission	Yes	Note 2 regarding three phase faults being sufficient evidence for SLG faults is an excellent addition, thank you. For P3 and P5 it should be made clearer that note 1 AND note 9 apply, maybe by using a comma in-between, not a note 19 that I wasn't able to locate. For Note 9, reading the context it applies only to P3, P5 and P6, but not to P1. To apply this to actual study methodology, in responding to a P1 event Note 9 can not be applied when returning the system to a continuous (sustainable) state. However after those adjustments are made if additional adjustments are needed to make the system "secure", that is prepared for the next event in the P3 or P6 contingency, then note 9 can be applied? Is

Organization	Yes or No	Comments for Question 10
		this a correct understanding?
Response: Several footnote reference errors were reflected in Table 1 when migrating from Draft 3 to Draft 4 that led to unfortunate confusion. In Draft 5, the SDT has corrected the footnote references and a detailed explanation of the changes required is summarized in the above Summary Considerations for Question 10. Footnote 9 is now applied to all "No" items for the column "Interruption of Firm Transmission Service Allowed". Footnote 9 clarifies that Firm Transmission Service can be interrupted so long as appropriate re-dispatch of resources are available and obligated to re-dispatch without any firm Load loss and that Facility ratings are maintained. Planning events P0, P1, and P2 now also include footnote 9 and is allowed both as a System adjustment to prepare for the next event and as a corrective action to the event studied. Please refer to the footnote for more details.		
NYISO	Yes	Question #10. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Yes
Exelon Transmission Planning	Yes	
FirstEnergy Corp	Yes	
Gainesville Regional Utilities	Yes	
Independent Electricity System Operator	Yes	
Progress Energy Carolinas	Yes	
SCE&G	Yes	
PJM	Yes	
ITC Holdings	Yes	none
Response: Thank you for your support of the SDT's work.		

11. The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments.

Summary Consideration: There were 5 main comments associated with this question.

1. Thirteen commenters requested clarification to better define the 60 month effective date for certain "raising the bar" performance requirements. The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period starts "beginning on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.

2. Four commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply.

3. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.
   Four commenters believe that it is inappropriate or in violation of Energy Policy Act 2005 for the revised standard to require building new facilities and some also question the requirement to self-report inability to meet Corrective Action Plan requirements. The Corrective Action Plan, however, does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible Load contracts, implementation of Demand Side Management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new Transmission Facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be subject to penalties.

3. Four commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.

4. Three commenters asked for clarification of the parenthetical language applicable to Events P1-2 and P1-3. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote 'b' in this manner and, therefore, the revised standard represents a "raising of the bar" for them.

Organization	Yes or No	Comments for Question 11
Lafayette Utilities System		LUS remains concerned as to the length of time permitted for implementation, and believes that it should be shorter, but would not oppose adoption of version 4, as it has now been clarified, if that is the only issue of concern. There may be ways, outside the standard development process, to limit the financial harms caused to others as a result of the failure to meet the clarified standard during the implementation period.
Response: Many industry entities have expressed concern that the stated implementation period may not be sufficient, particularly for major projects. The SDT believes it has struck the right balance between the differing views, and does not plan to shorten the time permitted for implementation as you have suggested.		
FRCC Transmission Working Group		The implementation plan needs to be clarified that during the first year the existing TPL standards are still in effect. As written it appears that only R1 and R8 are in effect and the existing TPL standards are not.Assessments are a year long process and are based on a year or more worth of studies, the study work and assessment are not executed in a single day. R2 through R7 is unclear what "coming into effect means". Please consider adding the following paragraph:"Entities are not required to alter their annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the year the old and new standard overlap. Therefore any assessment performed prior to R2-R7 going into effect shall meet R1, R8 and the prior TPL standards; an assessment under the revised standard is not required until the following annual cycle. An assessment performed after R2-R7 are in effect shall meet these new TPL Standard. The date the assessment is "performed" for the purposes of this phase in, shall be determined by the date the entity began formally sharing results with its neighbors under R8." Please clarify the parenthetical for P1-2 and P1-3. Is the intent of this parenthetical referring to Consequential Load Loss that is allowed for P1 events?
Response: The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12		

Organization	Yes or No	Comments for Question 11
months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification, as you suggested, is needed to cover the one-year period for months 13 through 24. The NERC standards process is clear that an existing standard that is being revised remains in force until the revised standard becomes effective. The SDT has reviewed your suggested addition to the paragraph that addresses the effective date for Requirements R2 through R6 plus Requirement R8. The SDT does not believe that your suggestion provides further clarification and the SDT has determined that no further change is warranted. The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
ERCOT ISO	No	* The implementation plan references revisions to the MOD standards. Should the team submit a SAR for the revision of the MOD standards to ensure TPL needs are considered? As stated in the comments for R1 " if the MOD standards are properly updated, there is no need to state MOD requirements in TPL-001.* Definition comments from Question 9 apply to implementation plan.* The Implementation Plan references R1 and R8 to be effective within 12 months of regulatory approval. R8 per the implementation plan state that the responsibilities of the PC and TP will be defined. This appears to be R7 of Draft 4 and the requirement language does not align. Conversely, the Effective Date should be revised to ensure the references to the requirements align properly. As written it states the assessment should be available before the assessment is complete. * During the 24 month transition period, any entity that can prove compliance with the revised TPL-001 should not have to prove compliance to the old TPL-001 through TPL-004. * The SAR should state that TPL-005 and TPL-006 are to be retired. The only place this has been found is within the implementation plan. It is not an intuitive place to find this information.
Response: The SDT referenced revisions to the MOD standards to establish a record of the need to fill a gap in the overall coordination among the Reliability Standards. The SDT does not intend to submit a SAR; rather the expectation is that NERC will take the necessary action to follow through to address this need at the appropriate point in time. See the SDT's response to your definition comments in Question 9. The Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT disagrees with your comment regarding demonstration of compliance during the 24 month transition period. At any point in time, one and only one set of TPL related requirements will be in force. It is those requirements that the Planning Coordinator and Transmission Planner must comply with and not future requirements that have not yet become effective. The SDT assumes that in your last comment the reference to SAR should have been Standard (or more precisely "Standard Development Roadmap"). (A Supplemental SAR was posted for comment and added to this project that does address the possibility of retiring TPL-005 and TPL-006.) The SDT agrees with your		

Organization	Yes or No	Comments for Question 11
suggestion, and the Roadmap has been modified to state: "TPL-005 & -006 issues are addressed in the fourth draft and those standards will also be replaced by TPL-001-1. (See page 1, last sentence of section titled "Proposed Action Plan and Description of Current Draft:" In addition, the "Version History" has been updated to indicate that requirements from TPL-005-0 and TPL-006-0 have been incorporated into TPL-001-1.		
NERC Standards Review Subcommittee	No	A. In the implementation plan, the provision which indicates if an entity doesn't construct in time that entity has to report itself as noncompliant. This is a violation of the energy policy act. Since FERC can't force an entity to built, this provision should be deleted. B. This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the Transmission Planner and Planning Authority should work with the applicable Transmission Owner (s) and Regional entity(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". C. The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. D. The MRO NSRS suggests that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".
Response: A. The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. B. The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.5 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.6 there is a requirement to review "implementation status."		

Organization	Yes or No	Comments for Question 11
C. Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. D. The SDT considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Progress Energy Florida, Inc.	No	As PEF is opposed to TPL-001-1 as a whole, we cannot comment on the details of the Implementation Plan, other than to say that given the fundamental inadequacies of TPL-001-1, PEF does not believe the Standard should be implemented at all.Given that the wording of Question 12 appears to imply that any general comments made in the Question 12 comments section would be unwelcome and disregarded, PEF would respectfully like to make the following comments regarding our overall position on TPL-001-1:PEF filed extensive comments for the 1st, 2nd and 3rd drafts of TPL-001-1 and voiced serious concerns about the consequences that Transmission Owners and ratepayers will undoubtedly face if TPL-001-1 were to be implemented. PEF respectfully asks the SDT to review PEFs previous comments, particularly from the perspective of the ratepayers. The average ratepayer in the U.S. is already experiencing high electricity bills based on fuel pass-through charges and electric utilities? needs to raise rates to successfully operate and maintain the system. Furthermore, the ratepayers have not been involved in this Standard drafting process, and indeed have not even been informed at even the most cursory level. PEF has pointed this out in previous comments, and the SDTs response has been inadequate. Given the erroneous approach of Table 1 in TPL-001-1 to gauge reliability based on whether or not firm transmission service or non-consequential load will be curtailed, implementation of the Standard will dramatically increase ratepayers? already-high rates with little or no appreciable reliability improvement. Additionally, Transmission Owners will be forced to reduce ATC in order to prevent compliance violations, thus shutting out Power Marketers and potentially resulting in construction of more new generation than is really needed. Another major conflict that TPL-001-1 will cause is a rift between the FERC/NERC regulatory environment and the various states? Public Service Commissions (PSC). The major transmission projects that TPL-001-1 will mandate (especially those mandated due to the overly burdensome and unnecessary > 300 kV section) will have to be approved for permitting and funding through Determination of Need hearings at the PSC. When questioned by the PSC on the need for such projects, Transmission Owners will be obligated to admit that the projects really aren't needed but for NERC's new TPL-001-1 Standard, which will undoubtedly result in the PSCs denial of approval. PEF also would like to note that the SDT still has not provided sufficient reason for the need to implement a new TPL Standard. PEF and its fellow members in FRCC have historically demonstrated excellent reliability while performing long-term Transmission Planning under the existing TPL Standards. There simply is no practical reason for improvement on the existing Standards. PEF is aware of the history of the drafting of a new TPL

Organization	Yes or No	Comments for Question 11
		Standard, however, having reviewed FERCs direction to NERC in this matter. Regarding this, PEF feels that NERC should have pointed out the likely consequences to merely following FERCs directions in their entirety; instead, NERC formed a SDT which proceeded to draft a new TPL Standard that satisfied each and every direction FERC had given. This approach has resulted in a draft Standard that is much too stringent, not conducive to significant reliability improvement and prohibitively expensive to implement.In conclusion, PEF strenuously opposes TPL-001-1, and feels the implementation of TPL-001-1 is unfair, irresponsible and unnecessary. PEF furthermore feels that it has sufficiently proven this in previous comments, and will continue to seek additional avenues to ensure that said comments are given proper consideration. TPL-001-1 is thus not in a condition to go to ballot, and it would be highly inappropriate to send this Standard to ballot given the major concerns that PEF and numerous other utilities within NERC have raised.
Response: The wording in Question 12 has created confusion among many commenters and was not intended to imply that if you checked the YES box, the SDT would not consider your comments. The SDT is obligated to consider all comments, make changes in the drafts that the SDT, as representatives of the entire industry, believe need to be made and provide responses to all comments. The SDT has carefully considered the PEF comments throughout the drafting process and has made changes to the drafts based on your comments and those received from the other commenters. Throughout the process, the SDT has been attempting to iterate toward a standard that the industry, as a whole, can support. The SDT, FERC, and the majority of the industry (through their comments) support the need to improve the TPL standards.		
Florida Power and Light	No	Do not understand the parenthetical for P1-2 and P1-3. The language is confusing and needs to be clarified. Isn't it referring to Consequential Load Loss that is allowed for P1 events?
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for changes that improved the Implementation Plan, however, MidAmerican does have a comment about the plan. MidAmerican urges the SDT to modify the implementation plan where it is indicated that any "entity which cannot fully implement their Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for these performance elements by that date shall self report themselves as being unable to meet the performance requirements of the Reliability Standard." This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the implementation plan should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005. This is a deal-killer for MidAmerican with regard to voting on this standard. MidAmerican believes that 4.1.2 and 4.3.3 as written would require responsible entities in the industry to add

Organization	Yes or No	Comments for Question 11
		additional modeling of relaying in dynamic stability models of our system. MidAmerican suggests that 4.3.3 be limited to transient swings on facilities 345 kV and above so as to limit this part of requirement 4 to those situations that are most likely to result in cascading. If the SDT determines not to add such a limitation, MidAmerican asks that the implementation time for R4 to be increased. MidAmerican believes that many responsible entities would need 3 years to add these relaying models to system stability models so that the fourth year additional transmission planning analysis in this respect is conducted. MidAmerican urges that the SDT increase the implementation time for R4 from 2 years to 4 years. (MidAmerican may this comment in response to Question 4 as well.)
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed. The SDT has modified the Implementation Plan to clarify the wording. Requirement R4, parts 4.1.2 and 4.3.3 do not necessarily require modeling of specific relays. Commercially available software includes a generic relay model which can easily be applied to every branch in the simulation. This generic relay includes assumed zone 1, 2, and 3 characteristics based on the branch impedance. If this model shows impedance swings in a branch element, then the Transmission Planner or Planning Coordinator can either take action according to the generic model results or investigate the characteristics of the relays actually used on that line. The SDT agrees that studying the impact of swings should be limited to the study area. However, the SDT does not believe this should be limited to only high voltage lines. Because Requirement R4, part 4.3.3 does not necessarily require modeling of specific relays (as described directly above), the SDT does not agree that a longer time is needed in the Implementation Plan.		
Oklahoma Gas & Electric	No	OG&E will need every bit of the 60 months time mentioned on page 3 under "Effective Date" to implement all indicated upgrades. There is benefit in hardening the OG&E electrical system for such protection system failures, such as P4 & P5, but it may not be cost effective.
Response: Thank you for your comment.		
Manitoba Hydro	No	Requirement R8, as the standard is currently written, doesn't match the language on page 2 of the discussion provided by the drafting team (i.e. related to determining individual and joint assessments). The drafting team should flip Requirements R7 and R8 so that the implementation plan matches the intent or modify the implementation plan.
Response: The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		

Organization	Yes or No	Comments for Question 11
Bonneville Power Administration	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Idaho Power	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Modesto Irrigation District Transmission Planning	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NV Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Pacific Gas and Electric Co.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Puget Sound Energy, Inc.	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Sacramento Municipal Utility District	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
San Diego Gas & Electric Co	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
Southern California Edison (SCE)	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
SRP	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five

Organization	Yes or No	Comments for Question 11
		years from the modeled year or five years from the effective date of this standard.
Western Area Power Adm - RMR	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the Effective Date of this standard.
Xcel Energy	No	Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem, or five years from the modeled year, or five years from the effective date of this standard.
Deseret Power	No	Comments: Revisions are necessary to the Effective Date language to clarify the 60 calendar months language for Corrective Action Plans. It is unclear if the entity has five years from the day they identify the problem or five years from the modeled year or five years from the effective date of this standard.
NorthWestern Energy	No	In the Effective Date section, 60 calendar months is allowed for Corrective Action Plans. When does the 60 month period start? From the day the problem is identified? From the modeled year? Or from the effective date of the standard?
Response: The SDT believes that the current language in Section A. 5 of the Standard, with a minor change that the SDT will incorporate in the next draft, is clear. That section, as modified, will state that the five year period begins "on the first day of the first calendar quarter following applicable regulatory approval" of the revised standard.		
MAPP	No	The last part of the Effective Date section deals with the requirement to submit a Corrective Action Plan, and then to submit a mitigation plan to be approved by the Regional Entity and NERC. Failure do get those done would result in the initiation of "settlement proceedings." This means that entities may be found non-compliant for failure to build facilities. That seems to fly in the face of the EPAct of 2005.
Response: The SDT disagrees with your characterization of the Corrective Action Plan. The Corrective Action Plan does not require construction of facilities per se and, therefore, the SDT does not believe that the language in the current draft violates the Energy Policy Act of 2005. Other choices available as part of the Corrective Action Plan besides constructing new facilities include use of interruptible load contracts, implementation of Demand Side management programs, and the addition of generation. The SDT understands that there may be certain circumstances where the only viable solution to a performance deficiency is to add a new transmission facility. This is no different than situations that Transmission Planners have faced under the current TPL standards as well as voluntary criteria that have existed for many years. The SDT also points out that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. As long as an acceptable mitigation plan is offered, the intent of the SDT is that the reporting entity will not be considered non-compliant nor will penalties be imposed.		
SERC Dynamics Review Subcommittee (DRS)	No	There is a concern about the last paragraph in the Implementation Plan. It is easy to interpret this language to state that the entity is noncompliant if the performance requirements are not completed within 5 years. The concern is that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For

Organization	Yes or No	Comments for Question 11
		instance, it typically takes 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. We strongly suggest increasing this time window to 10 years.
Response: The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure for mitigation in those situations where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
TVA System Planning	No	TVA agrees with the inclusion of P1-2 and P1-3 in the 60 month implementation window. However TVA also strongly suggests that all Planning Events be included in the same implementation window where local load was allowed to be dropped in the past in footnotes b and c of the existing TPL standards. In the first bullet under Effective Date, both Non-Consequential Load Loss and curtailment of Firm Transmission Service can be permitted for certain events up to 60 months. However these actions are not useful for stability related issues. TVA suggests that out of step relaying or other protection method be allowed in for stability related issues when situations do arise that are beyond the control of the TP or PC. TVA is very concerned about the last paragraph in the Implementation Plan. TVA interprets this language to state that the entity is basically noncompliant if the mentioned Corrective Action Plans are not implemented within 60 calendar months. Due to the large amount of work that some utilities will have to meet these new requirements, TVA strongly suggests that the utilities be found compliant if the utilities are still putting a good faith effort forward in trying to meet the new standards, such as for constructing a long 500-kV transmission line that may take at least 10 years to construct TVA still believes that since breaker duty was not included in the previous TPL standards, this should also have a 60 month implementation window as well due to this now becoming a new TPL compliance issue. TVA noted this same comment in Posting #3; however, TVA requests that this be reconsidered due to being a new official TPL requirement like the other new requirements have with the 60 month implementation window. TVA is concerned that the 60 calendar month window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time window to 10 years.
Response: The SDT believes that footnote 'c' conditions in the current TPL standards are adequately addressed in the revised standard. The SDT disagrees that Non-Consequential Load Loss is not useful for Stability related issues. The tripping of such Load as part of an SPS could be accomplished quickly enough to improve Stability margins. Furthermore, there is nothing in the revised standard that precludes the use of out of step relaying. The SDT believes that your interpretation of the last paragraph of the Implementation Plan is incorrect. Should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to provide a mitigation plan to their Regional		

Organization	Yes or No	Comments for Question 11
Entity. Although the SDT agrees that the breaker duty requirement is new to this revision of the standard, the SDT does not believe that there is a need to allow a 60 month transition period for this requirement to become effective. Replacing over-dutied circuit breakers can often be accomplished within the 24 month period provided by the effective date of the requirement. In those cases where the replacement could take longer, there are other approaches available to mitigate the over-duty condition. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner.		
Ameren	No	We appreciate that the Standards Drafting Team has proposed delayed effective dates to allow tripping of Non-Consequential Load or curtailment of Firm Transmission Service for a number of categories of contingency events to allow more time to become compliant. However, we do not look forward to having to self-report non-compliance because the industry and the government changed the planning rules in the middle of the game.
Response: Please note that should a Transmission Planner or Planning Coordinator find that they can not meet the performance requirements by the end of the 60 month transition period, they would need to submit a mitigation plan to their Regional Entity. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties.		
FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained.Implementation of transmission system action plans depends on the actions of many other functional entities, other than PCs or TPs. PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. For example, an RTO/ISO may act as both the PC and the TP for its transmission owner or transmission operator membership, however, the RTO/ISO should not be subject to compliance sanctions for incomplete projects that it does not have direct responsibility.FirstEnergy suggests that a new TPL standard is required to successfully accomplish the vision and endpoint that this drafting team has in mind. It is our opinion that the TO, TOP, DP and GO are needed as applicable entities to bring to fruition the capital enforcement projects or operating procedures that are identified by the PC/TP. This TPL-001-1 standard should stop at the conclusion of studies, assessments and development of Corrective Action Plans and a new TPL standard should be developed to address implementation of Corrective Action Plans.
Response: The SDT has considered your position and still believes that the requirement to implement the Corrective Action Plan is appropriate. Furthermore, the SDT does not believe that the standard should apply to additional entities beyond the Transmission Planner and Planning Coordinator. In fact, doing so would tend to make implementation of the Corrective Action Plan more difficult by reducing clarity as to who is the responsible entity. Where the Transmission Planner or Planning Coordinator is an RTO, agreements between the RTO and its members, which typically include the entities you describe, require those members to implement plans		

Organization	Yes or No	Comments for Question 11
developed by the RTO. Where the Transmission Planner or Planning Coordinator is not an RTO, in most cases, they are a vertically integrated utility that includes all of the entities that you describe. In other cases, the Transmission Planner and Planning Coordinator can establish agreements with the entities for which they are providing those services to specify responsibilities for implementation of the Corrective Action Plan.		
American Transmission Company	No	We offer the following comments.This standard does not contain any requirements regarding the implementation of the Corrective Action Plans. So, the wording in this section of "Any entity that cannot fully implement . . . ", should be replaced with wording like, "If the Corrective Action Plans to eliminate the need . . . can not be implemented within 60 calendar months . . . then the TP and PA should work with the applicable TO(s) and Re(s) to develop mitigation plans for revised Corrective Action Plans until the implementation issue is resolved". The proposed standard implies that the 24 month time period (for R2-R7) and 60 month time period (for specific allowances for selected event categories) run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new corrective action plans. It may not be feasible to install some BES facilities, especially above 300 kV, in less than 3 years. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in more "implementation dependent" terms for this "one time" transient period, rather than specific and possibly inappropriate "fixed timeframe" terms. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2, part 2.7.5) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented".The "implementation dependent" approach may allow the removal of all or part of the text on implementation exceptions and mitigation procedures that do not appear to be suitable in an Effective Date section.
Response: The SDT believes that the requirement language is clear that the Corrective Action Plan shall be implemented. In Requirement 2, part 2.7.3 reference is made to "implementation of a Corrective Action Plan," and in Requirement R2, part 2.7.4 there is a requirement to review "implementation status." Your interpretation that the 24 month and 60 month time periods run in parallel is correct. The SDT understands that some large projects that are part of the Corrective Action Plan may take more than 60 months to complete. However, the SDT also believes that some time limit must be placed on the Corrective Action Plan and 60 months was chosen to strike a balance between those commenters who requested more time and those who would like to see corrective actions completed sooner. The SDT also provided a procedure to submit a mitigation plan to their Regional Entity where 60 months was insufficient. It is the intent of the SDT that the development of an acceptable mitigation plan will avoid penalties. The SDT has modified the Implementation Plan to clarify the wording. The SDT also considered your suggested restatement of effective dates during the transition period. The SDT does not believe that such a change would materially improve the standard language. In fact, your specific example would be problematic because Requirement R2, part 2.7.5 applies universally not just to the transition period.		
Tri-State Generation and Transmission Association	No	Yes and No. We see some potential problems.12 months after BOT adoption, R1 maintain system models - becomes effective. Why delay Also 12 months after adoption, R8 distribute planning assessment results - becomes effective. As an assessment cannot be distributed before it is completed, this must be coordinated with R2.24 months after BOT adoption R2 Annual Planning Assessment - timing must coordinate with R8 above.

Organization	Yes or No	Comments for Question 11
Response: The SDT attempted to strike a balance between those commenters who requested more time and those who would like to see some requirements become effective earlier. In the case of Requirement R1, the SDT saw little value in making this requirement effective before 12 months. Furthermore, doing so would break the standard effective dates into yet another time period possibly leading to confusion as to which portions of the revised and old standards are in effect. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirements R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval.		
American Electric Power	Yes	
British Columbia Transmission Corp	Yes	
Central Maine Power Company	Yes	
Exelon Transmission Planning	Yes	
Florida Municipal Power Agency, and its Member Cities	Yes	
Gainesville Regional Utilities	Yes	
Hydro-Québec TransEnergie (HQT)	Yes	
Independent Electricity System Operator	Yes	
ISO New England	Yes	
Northeast Power Coordinating Council--RSC	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings, Inc. - Affiliates PHI	Yes	

Organization	Yes or No	Comments for Question 11
Progress Energy Carolinas	Yes	
SCE&G	Yes	
SERC Planning Standards Subcommittee	Yes	
Southern Company	Yes	
SRC of ISO/RTO	Yes	
TIS	Yes	
United Illuminating	Yes	
US Bureau of Reclamation	Yes	
Utility System Efficiencies, Inc. (USE)	Yes	
ITC Holdings	Yes	none
National Grid	Yes	None.
NYISO	Yes	Question #11 The SDT has provided a revised Implementation Plan as part of this posting. Do you agree with the revisions to the Plan? If not, please provide specific comments. Yes
Response: Thank you for your input.		
Orlando Utilities Commission	Yes	The phasing in of the higher performance criteria is a very reasonable approach. The implementation plan needs to be painfully clear that during the first year the existing TPL standards are still in effect, and that R1 and R8 are in effect in addition. Most NERC standards have one revision take effect on a specific date, make the old version out of date. In this case however if TPL 001 retires the prior standards, then only R1 and R8 would need to be performed in the first year, which I do not believe that is the intent. In addition to this, further clarification may be needed for the application of R2-R7, even if they were to come into effect the first year. Assessments are a year long process and published once a annually. As an example many entities “publish” or finish the Assessment in December, that being the culmination of months of work. If R2-R7 are effective on June 2011 then the intended application seems to be that the assessment in Dec 2011 should comply with the new

Organization	Yes or No	Comments for Question 11
		standard. Is that the intent, or would there need to be a valid assessment based on the new standard available the day the standard is in effect? Maybe phrasing to this effect. "Entities are not required to alter there annual schedule based on the R2-R7 requirements going into place or have duplicate efforts at assessments in the annual period the old and new standard overlap. Any assessment completed (as determined by the date that the entity formally shared results under R8) after the effective date for R2-R7 shall comply with those requirements."
Response: First, it should be noted that the Implementation Plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. The SDT does not believe that a clarification is needed to cover the one-year period for months 13 through 24 when Requirements R1 and R7 plus the existing standard will be in effect because Requirements R1 and R7 are new requirements that do not replace any requirements in the existing standards. The NERC standards process is clear that an existing standard that is being revised remains in force until replaced by revised standard requirements becomes effective. The SDT believes that sufficient flexibility was provided in the definition of Year One to permit Transmission Planners and Planning Coordinators to maintain their current assessment schedule if they desire. It is the SDT's expectation that any assessment initiated 24 months or more after the effective date of Requirements R2 through R6 plus Requirement R8 would adhere to the revised standard requirements.		
Duke Energy	Yes	Yes, however we don't understand the meaning of this phrase which follows P1-2 and P1-3: "for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element".
Response: The parenthetical phrase related to P1-2 and P1-3 is intended to limit the application of the 60 calendar month exception to those situations where footnote b of the existing standards was interpreted to mean that controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element is permitted. The SDT took this position in recognition of the fact that a significant number of entities interpret footnote b in this manner and, therefore, the revised standard represents a "raising of the bar" for them.		
PJM	No	The timeframe to gather additional protection and dynamic load modeling data is too short. Millions of pieces of new data will need to be collected and validated before valid models will be available. Extend the period to 24 months.
Response: The SDT does not intend that detailed protection and dynamic Load models will be required for all Transmission elements and Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." Furthermore, there is no explicit requirement in Requirement R1 for representation of protection schemes. To the extent such detail is needed, it would apply to the Stability studies required as part of Requirement R4. Requirements R2 and R4 are already specified to be effective in 24 months following regulatory approval.		

12. Do you believe that this standard is ready to go to ballot? (if 'No' is checked here, the SDT will consider that comments raised on the other questions drove that decision.)

Summary Consideration: The initial response of the majority of the commenters was that this standard is not ready to go to ballot. The reasons for the negative responses included: 1) a desire to have a sample detailed Planning Assessment, 2) concern over the value of the "raising the bar" for EHV Facilities, 3) concern with excessive study or documentation requirements, 4) concern that the Implementation Plan could be interpreted to require construction (contrary to the Energy Policy Act of 2005), and 5) concern that some of the requirements are not clear and contain ambiguous language. The SDT learned that some commenters voted 'No' to ensure that their comments would be reviewed and considered by the SDT. Other commenters stated that this draft was ready to go to ballot and the remaining commenters stated that it was ready for ballot with favorable consideration of the comments provided.

The SDT has responded to all of these concerns in the responses to the comments. The majority of the issues raised about unclear and ambiguous language were clarified without material changes to the draft. The SDT evaluated the comments provided in response to this draft and has determined that the majority of the remaining 'No' votes are because the commenters disagree with the position(s) taken by the SDT and not because the standard is unclear or unenforceable. The issues that were raised about increased performance requirements, increased study requirements, and increased documentation have been vetted by the industry and the SDT through four posting periods over the last 3 years.

The SDT has posted this standard for four posting periods over the last 3 years. In the previous three postings, the SDT has developed more than 1300 pages of comments and responses. The form of the main requirements and sub-parts has changed in response to industry comment, but the substance of the main requirements and sub-parts has not changed substantially in the last two postings.

The SDT has not made any substantive or contextual changes with this posting and has determined that this standard is ready to go to ballot.

Organization	Yes or No	Comments for Question 12
Sacramento Municipal Utility District		The SDT should develop a detailed sample assessment prior to balloting so that the SDT's hard work can be voted on by an informed ballot pool.
Platte River Power Authority	No	No, not until there is some form of common understanding, among the people reading this draft, of how to interpret from Table 1 (Planned and Extreme) all the contingency scenarios that will be required to demonstrate full compliance with the standard. It would be helpful if the Drafting Team spearheaded some workshops to walk us through how this might be done.
Response: The SDT agrees that it is important to have an informed ballot pool; however, the SDT does not plan to develop a sample assessment prior to balloting. The SDT has taken several steps to inform the industry and will continue those outreach efforts.		

Organization	Yes or No	Comments for Question 12
FRCC Transmission Working Group		We the FRCC TWG feel that the standard is very close to ballot, but the drafting team still needs to address several issues raised in the comments before balloting.
CenterPoint Energy	No	CenterPoint Energy is well aware of the diligence of the SDT in preparing this major consolidation and rewrite of the existing TPL standards. CenterPoint Energy believes this latest version is almost ready for ballot. CenterPoint Energy respectfully requests consideration by the SDT of the refinements to this latest draft proposed by CenterPoint Energy.
FirstEnergy Corp	No	FirstEnergy does not believe the proposed TPL-001-1 standard is ready for ballot until our primary concern with the Implementation Plan as identified in our comment to Q11 is addressed. Additionally, our most pressing secondary concern is the modeling required for Protection Systems related to 4.3.3. Finally, we believe the standard is overly burdensome related to the annual near-term study requirements as stated in 2.1.1 as noted by our Q2 comments.
SERC Dynamics Review Subcommittee (DRS)	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
SERC Planning Standards Subcommittee	No	If the revisions recommended above are adopted, the standard would then be ready for ballot. We commend the drafting team for their efforts in preparing this draft standard for ballot.
Midwest ISO	No	Only if the proposed changes and questions are adequately addressed.
NorthWestern Energy	No	Since the definition section needs to be changed, some wording in the requirements needs to be modified, and the footnote numbering in Table 1 need to be corrected, we believe another draft should be issued before taking this standard to ballot.
US Bureau of Reclamation	No	The definitions require revisions. Additional work is required to clarify Corrective Action plan items, agreement on votlage limits and acceptable deviations, as well as coordination of Planning Assessment results with owner entities.
SRC of ISO/RTO	No	The proposed changes and comments need to be adequately addressed before any ballot.
Independent Electricity System Operator	No	The standard has become overly prescriptive and unnecessary (see our comments under Q2, Q3 and Q4 on Part 2.1.4, Parts 3.3 to 3.6, Parts 4.3 to 4.5. Much work is needed to condense or remove these requirements.
Hydro-Québec TransEnergie (HQT)	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard should go to ballot.
Northeast Power Coordinating	No	There are still issues as indicated in the submitted comments that need to be addressed before this standard

Organization	Yes or No	Comments for Question 12
Council--RSC		should go to ballot.
Orlando Utilities Commission	Yes	I have not seen all the comments of other entities, so there may be some comments that would require the standard be reposted. Assuming I have correctly read the standard, all of my comments would improve the communication of the existing intent, not alter the requirement.
American Electric Power	Yes	The SDT has done an exceptional job working through complex issues and varying perspectives to arrive at this solid draft. This version has significantly improved the standard and has raised the bar where appropriate to do so. With favorable consideration of comments from this round, the revised draft should be ready for ballot.
Duke Energy	Yes	Yes, assuming our comments are addressed effectively.
American Transmission Company	Yes	Yes, if the proposed changes and questions are adequately addressed.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments.		
Xcel Energy	No	As currently drafted, several outages identified in Categories P2, P4, and P5 appear to potentially result in the same elements being removed from service, so therefore the same event, even though the initiating event is different.
Response: The SDT agrees that some planning events will result in the same elements being removed from service. However, the similarities may only be valid from a steady-state view point and care must be taken to review the events in the Stability timeframe due to delayed clearing modes that may result from the initiating event. For example, a bus fault and a stuck breaker may each clear a bus; however, the stuck breaker will have different reaction times due to the delayed clearing mode and therefore may warrant a review in a Stability environment. The standard allows the Transmission Planner and Planning Coordinator flexibility in using engineering judgment for the Table 1 events in which it studies for both the steady-state and Stability environments. Both Requirements R3 (steady-state study) and R4 (Stability study) include text indicating the Transmission Planner and Planning Coordinator are to study those events "…that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance …" If a Transmission Planner/Planning Coordinator can justify that certain events are duplicative for a given timeframe then at their discretion they may elect to limit their Contingency list so long as their entire Contingency list covers the events that "produce the more severe impacts" for their System.		
SCE&G	No	As per our comments.
British Columbia Transmission Corp	No	
Florida Power and Light	No	
Manitoba Hydro	No	

Organization	Yes or No	Comments for Question 12
Northeast Utilities	No	
Pepco Holdings, Inc. - Affiliates PHI	No	
Progress Energy Florida, Inc.	No	
United Illuminating	No	
PJM	No	
Bonneville Power Administration	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Idaho Power	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Modesto Irrigation District Transmission Planning	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
NV Energy	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Pacific Gas and Electric Co.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Puget Sound Energy, Inc.	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
San Diego Gas & Electric Co	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.

Organization	Yes or No	Comments for Question 12
Southern California Edison (SCE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Utility System Efficiencies, Inc. (USE)	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe additional modifications are necessary prior to taking this standard to ballot.
Western Area Power Adm - RMR	No	Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, I believe modifications are necessary prior to taking this standard to ballot.
Deseret Power	No	Comments: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
SRP	No	: Based on the unclear or ambiguous language identified in the comments above as well as the confusion noted in the Table 1 regarding outages and footnotes, we believe modifications are necessary prior to taking this standard to ballot.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments, including the clarifications that the SDT made concerning the Table 1 outages and footnotes.		
Ameren	No	Certainly the proposed assessment and documentation requirements are more comprehensive and the performance standards are more rigorous than the existing TPL-001 through TPL-004 reliability standards. But, by performing the proposed additional required studies and documenting the results, how much additional reliability will be provided to the System? None, but we will be auditably compliant. More planning engineers will need to be hired to perform the studies and develop the assessments, more librarians will need to be hired to keep track of all the paperwork and computer file storage, and more trees will be killed printing the paper to send to all those that need to review the documents and provide comments. Is this the most effective way to improve transmission system reliability from a planning perspective? What measurable benefits are to be accrued for providing an EHV system that would not result in the loss of non-consequential load for P2-2, P2-3, P4 1-5, and P5 1-5 planning events, all of which are rare and infrequent? What is the estimated cost for this incremental “improvement” to cover the System’s short-comings? The EHV system is already the most reliable portion of the BES with an availability of approximately 99% and can withstand extreme events without widespread outages.
Response: The SDT believes that the added clarity of the proposed standard is very important to ensure that entities can clearly understand the requirements. Even though EHV outages are less frequent than outages of lower voltage Transmission Facilities, the SDT believes that there should not be Non-Consequential Load Loss		

Organization	Yes or No	Comments for Question 12
for the single Contingencies in P2 and for the failure of a circuit breaker or Protection Systems in the P4 and P5 events.		
ITC Holdings	No	Comments: In addition to our other comments, ITC offers the following feedback. The requirements are rather complex, yet the measures seem extremely simple. Have they been discussed in any detail and are they sufficiently described to insure and understanding of just what is expected (ie., Are the requirements sufficient as measures in and of themselves?) R2.1.5 for example discusses “spare equipment strategy for long-lead time facilities”. If I have a 2p.u. xfmr, can I assume it spares all similar category transformers or would I have to study P0,P1 and P2 contingencies if it replaces a 3 p.u. xfmr. If I don’t have a spare and can’t meet P0,P1 or P2 contingencies without load shedding, do I need a CAP. See also our comments under R3.4.1. We haven’t reviewed all requirements and all measures in this fashion but suggest the SDT do so.
Response: The SDT has reviewed the measures and believe that they are sufficient to measure compliance with the requirements. The issues raised about transformer assumptions are System specific and are, therefore, not addressed by the standard. If you do not have a spare for a piece of equipment with a long lead time and your System cannot meet the performance requirements without that piece of equipment, you must have a Corrective Action Plan to address that deficiency. Part 3.4.1: See response to Q3.		
ERCOT ISO	No	ERCOT recognizes that much effort has been put into this standard. However, a lot of effort will be required to ensure documentation for the standard is sufficient, yet the benefit of the additional documentation effort required is marginal. For a standard like this, stating every possible issue and studying every possible scenario is not realistic and potentially will lead to complacency very little planning outside the scope of this standard will be done regardless of the system needs.
Response: The SDT has attempted to clarify areas where the existing standard is ambiguous. In this effort to clarify, the SDT has introduced new areas where documentation is required; however, in most instances, this documentation was already implicitly required. The SDT believes that it has limited the documentation requirements to the minimum required to ensure thorough evaluation of BES reliability. While the SDT has expanded the scenario analysis required with additional study year requirements and sensitivity requirements, the SDT has not developed an exhaustive list of studies or analysis that the planner must conduct. The SDT believes that the requirements contained within the standard are the minimum requirements necessary to evaluate BES reliability, while continuing to give the planner latitude in the portfolio of studies that the planner will conduct.		
NERC System Protection and Control Subcommittee (SPCS)	No	Inclusion of the changes proposed by the System Protection and Control Subcommittee (SPCS) drove the belief that the standard is not ready to go to ballot. Such changes would be substantial enough to invoke another round of comments by the Industry.
Response: Please see the comment responses for each question to see how the SDT addressed the issues raised in your comments. The SDT has not made substantial changes based on the comments.		
Central Maine Power Company	No	It is closer, but there are still some unacceptable issues that need to be addressed.

Organization	Yes or No	Comments for Question 12
ISO New England	No	It is closer, but there are still some unacceptable issues that need to be addressed. The single most important comment is to define the base assumptions for use in studies.
National Grid	No	It is closer, but there are still some unacceptable issues that need to be addressed.
Response: The SDT has made changes based on the comments. Please see the individual comment responses to see how the SDT addressed the issues raised in your comments.		
MAPP	No	MAPPCOR urges the SDT to modify the effective date where it is indicated that any “entity that cannot fully implement its Corrective Action Plan to eliminate the need to trip Non-Consequential Load or curtail Firm Transmission Service for the above listed performance elements within 60 calendar months of the compliance date for Requirements R2 through R4 shall self report itself as being unable to meet the performance requirements of this Reliability Standard.” This is essentially requiring an entity to self report for failing to build facilities. The Energy Policy Act of 2005 did not give FERC and therefore, NERC, the authority to require construction of electric facilities. Therefore, this implementation plan is implying an authority that is not given to FERC or NERC. This provision of the effective date should be completely deleted from the standard, the provision to state that one is non-compliant for this should be deleted from the standard, or there should be a statement that such a requirement is subject to limitations of the Energy Policy Act of 2005.
Response: The SDT has modified the language in the Implementation Plan to address this concern. Additionally, the last paragraph of the effective date section of the standard was eliminated to address this concern.		
NERC Standards Review Subcommittee	No	More discussion is needed pertaining to this standard.
Response: The SDT believes with the clarifications made in Draft 5 that the standard is ready for ballot.		
Portland General Electric Co.	No	PGE believes that this standard should not go to ballot without revisions to restrict the scope of the standard as outlined above.
Response: The SDT has not restricted the standard to Facilities >200 kV, as proposed in your comment to Q2. The Facilities that make up the Bulk Electric System (BES) are defined by each Regional Entity and this standard must address all of the BES Facilities to ensure reliability of the BES.		
NYISO	No	Question #12 Do you believe that this standard is ready to go to ballot? (if “No” is checked here, the SDT will consider that comments raised on the other questions drove that decision.) No. Too many significant questions and key definitions remain unanswered.

Organization	Yes or No	Comments for Question 12
		Table 1 - General comment - Footnotes needs significant clean-up Page 16 Note (a) this note is placed under "Steady State & Stability" but issues of voltage instability, cascading outages, and uncontrolled islanding apply only to stability Note (f) Does this refer to "Normal Ratings"? Please provide clarity. Note (g) "System steady state" should be defined by applicable regional entity. Note (i) indicates that one cannot meet steady state requirements by depending on end-user owned equipment. Please clarify the purpose and performance requirement on this note with respect to end-user schemes and possible arrangements already in place to trip end-user equipment. Page 17 P5 As written, this requirement replicates a fault causing a loss of station anywhere that there is only one protection system. This is overly severe and would lead to the requirement for fully redundant protection systems at many stations. Page 18 P7 for Event 1 (the loss of two adjacent circuits), this needs to specify if these are the same phase or different phasesPage 19How could any system planner reasonably and accurately portray what contingencies might occur from any single or combination of extreme events listed? PAGE 20 Is the one mile exclusion in footnote 14 a contiguous mile, or a total of one mile for the entire length of the lines? (i.e. Are multiple instances of common towers or common rights of way exempt if each instance is less than a mile?)General Comment:The NYISO would like to align itself in supporting the following comment submitted by the NPCC: We agree with the SDT that more stringent performance requirements be applied for Facilities that do not directly serve end-use Load customers but rather represent the backbone of the electric power grid and act as the medium for moving large amounts of power from production to various Load centers.However, as HQT commented on previous draft, we strongly believe that the EHV breakpoint for these more stringent requirements, defined in note 3 of table 1 as "all Facilities greater than 300 kV" is not appropriately defined and should be reviewed. The SDT have not demonstrated that a uniform voltage-level threshold could adequately covers all different power system types in North America and we strongly believe that significant additional costs will be incurred without proportional or measurable reliability benefits if this definition is not changed.We propose to modify EHV definition "all Facilities greater than 300 kV" by the following "Facilities representing the backbone of the System, generally at voltage greater than 300 kV, as determined by the Planning Coordinator and approved by Regional Entity." In using such a language, we believe that the extra investment required would go towards real improvement of the reliability of the interconnected System.

Response: Footnote references were corrected.

The SDT does not agree that Header Note "a" should only apply in the Stability section, since these conditions should not be allowed to occur in any timeframe.

Header Note "f" is not limited to normal ratings. Facility Ratings are defined in the NERC Glossary as: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility. Since these ratings are time

Organization	Yes or No	Comments for Question 12
dependent, a rating higher than a normal rating can be utilized, as long as Header Note "e" is maintained. Header Note "g" – The SDT believes that it is appropriate for each Transmission Planner and Planning Coordinator to define the acceptable Steady state voltages. Header Note "i" – The purpose of the restriction is to ensure that the planner develops the System so that all of the Load, including voltage sensitive Load, can be served after an event. The P5 event is a Category C event in the existing Table, and the SDT changed the requirement for >300 kV so that Non-Consequential Load Loss is not acceptable. For the P7 event, it is the responsibility of the planner to evaluate the loss of adjacent circuits as the planner believes is appropriate for their System. For footnote 14, the SDT intends to limit the exposure for multiple circuits to less than 1 mile total. It does not matter whether the exposure is contiguous or not. The SDT declines to add "generally" to the requirements that apply to Facilities operated at greater than 300 kV as that would make the requirements unmeasurable.		
Lakeland Electric	No	The effective section needs more clarification:The assessment and supporting studies in accordance with the new standard is not effective until two years after this new standard is approved, however, it is required (R8) that PCs and TPs distribute its planning Assessment and results to adjacent PCs and TPs one year after the standard is effective. Which standard does the SDT intend for the (the old TPL standards or the new TPL standard) PCs and TPs to use to assess their system during the first year after the standard is approved? R2 thru R7 (assessments and studies) becomes effective 2 yrs after regulatory approval. That means that utilities have three years left to build/upgrade the projects identified in the studies/assessment (which was not effective until the 2nd year). Three years might not be enough to build long EHV or HV lines to meet the standard requirement.What happens between year 5 and year 7? After year 5, utilities are not allowed to trip Non-Consequential Load or curtailment of Firm Transmission Service for those specific contingency listed. However, the utilities do not have to self report until year 7 ("60 months of the compliance date for R2 through R4")
Response: A number of commenters pointed out a typographical error that reversed the numbering of Requirements R7 and R8 in the Implementation Plan. The implementation plan has been corrected to reflect the SDT's original intent that Requirements R1 and R7 (not Requirement R8) become effective 12 months after approval and Requirements R2 through R6 plus Requirement R8 (not Requirement R7), with the noted exceptions, become effective 24 months after approval. Changes were made to the Standard and the Implementation Plan document. Consequently, the revised assessment requirements and Requirement R8 are all effective 24 months after applicable regulatory approval. During the one-year period after Requirements R1 and R7 become effective and before the remaining requirements become effective, Transmission Planners and Planning Coordinators should conduct their assessments based on the current requirements. The SDT considered the concerns of a number of commenters as to whether 60 months will be sufficient to complete major projects when TPL-001-1, draft 3 was prepared, and the SDT again discussed its position in light of the comments received from this posting. The SDT continues to believe that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The current draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.3 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the		

Organization	Yes or No	Comments for Question 12
Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control. All parts of the revised standard will be in effect 60 months after applicable regulatory approval, so there are no unique requirements that exist only between year 5 and year 7.		
Tri-State Generation and Transmission Association	No	The SDT needs to look at the Measures section more closely. Please consider: In what jurisdiction could it be developed, and would it be possible to develop estimates of costs to meet the new requirements contained in this draft TPL by Reliability Area, then have utilities examine whether there will be a corresponding increase in Bulk Transmission System reliability?The primary directive of NERC Reliability Standards is to improve system reliability and thus minimize potential cascading of the Bulk Electric System. This developing TPL Standard will provide some needed clarification and perhaps better uniformity of Planning Study work. Any Standard that would move us toward the primary goal should be attended to meticulously. The SDT must endeavor to ensure this standard moves us in that direction and does not simply give us more structure. That said, please use this guiding test as we put final touches on this standard: Will each Requirement decrease the potential of cascading outages and increase service reliability?
Response: Throughout the development process, the SDT has been cognizant of the changes in the requirements and their potential impact on BES reliability. The SDT believes that all of the requirements and their sub-parts contained in this standard address the NERC directive of ensuring Bulk Electric System reliability.		
Oklahoma Gas & Electric	No	This document needs to be cyrstal clear because of compliance requirements. It still needs some work to clarify some definitions and address duplication of work (between the Transmission Planner and Planning Coordinator).
Response: The SDT has worked diligently to make the requirements very clear and unambiguous. See responses to Q9 for changes made to the definitions in this draft. The SDT has written the standard such that each Transmission Planner and each Planning Coordinator is responsible for each requirement and its sub-parts.		
TVA System Planning	No	TVA is very concerned about the tremendous amount of additional work that has been proposed for both the steady state and for stability analysis. TVA believes that there will be very little payoff for these additional studies. TVA is concerned that the costs to meet the new requirements contained in this draft TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in customer rates that will be required to support these new facilities.
Response: The SDT has made efforts to ensure that new study requirements in the proposed standard contribute to the completeness of Planning Assessments and remove the ambiguity in the existing standards. The SDT believes that the higher performance requirements are necessary to ensure a reliable BES.		
Gainesville Regional Utilities	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Comments for Question 12
Progress Energy Carolinas	Yes	
Southern Company	Yes	
TIS	Yes	
Exelon Transmission Planning	Yes	Concern is with the issues raised in Question 2. Performance requirements should be based on the voltage level of the overloaded element.
Response: Please see the comment responses for Q2 to see how the SDT addressed the issues raised in your comments. The SDT disagrees that the voltage level of the overloaded element should be used to determine acceptable performance.		
Lafayette Utilities System	Yes	LUS believes that the current draft of the standard is a significant improvement on the previous draft, and that the standard is ready to go to ballot. While there are elements of the standard which we consider to be short of the ideal, we recognize that this has been a consensus-building process and that the version 4, as explained and clarified, is a compromise which may be the best attainable for the industry at the moment.
Response: Thank you for your comment.		