NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Generator Verification – PRC-024-1 — Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the Second Posting of PRC-024-1 Generator Performance During Voltage and Frequency Excursions. These standards were posted for a 45-day public comment period from June 15, 2011 through August 1, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. Also included in this report are comments received from the initial ballots and non-binding polls conducted during the last ten days of the 45-day comment period. There were 66 sets of comments, including comments from approximately 185 different people from approximately 120 companies representing all 10 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Generator-Verification-Project-2007-09.html

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 of Standards and Training, Herb Schrayshuen, at 404-446-2563 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration:

The GVSDT proposed two new definitions for Voltage Excursion and Frequency Excursion. A slight majority agreed with the proposed definitions. The majority of "No" votes disagreed with the voltage excursion portion of the question while there was only one vote disagreeing with the frequency excursion portion. After reviewing all comments the SDT made the following changes:

1. The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.

2. Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the "no trip" zone.

3. Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf

definition was modified to include the phrase, "voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve."

The GVSDT proposed Requirements R1 and R2 to detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Stakeholders were asked if they believed that the draft of these two requirements, including footnote 1, clarified that a Generator Owner is not required to have protective relaying installed or set for these functions. Stakeholders generally agreed that footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3 and provided clarifying language examples. In response, the SDT made the following changes:

1. The Requirement Parts were revised in Requirement R1. Part 1.5 was moved into the body of R1. The requirement now reads:

    "R1. Each Generator Owner that has generator frequency protective relaying[2] activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

    1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.

    1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

2. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining Parts were modified to clarify intent. The requirement now reads:

    "R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of interconnection) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and

[2] Each Generator Owner is not required to have frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit.

communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant.: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

"3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.

- The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard)."

During the Quality Review process prior to the previous posting, a new requirement R4 was added based on the comments of the reviewers. This resulted in requirement numbers being incorrect for Questions 3 and 4. ***The GVSDT will ask these two questions again on the upcoming comment form for the successive ballot.*** A summary of the comments received is in the following paragraphs.

Relating to question 3: The GVSDT added Requirement R5 to allow owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information was intended to provide Transmission Planners with information useful in performing planning studies. In the comment form, the question erroneously asked about R4 rather than R5. A few commenters made comments regarding R4 while the vast majority commented related to R5.

Several commenters felt that there is no additional reliability gain in Requirement R5. Their comments indicated that the information is not useful and that there is little technical value in this information. A few commenters expressed the opinion that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2. Further, several commenters expressed the opinion that it is unlikely that any steam plant will survive for the entire “no trip zones” of the attachments. Other, less frequent, comments included the following:

- R1-R4 adequately fulfill the purpose of the standard.
- Standard requirements should be limited to devices that directly respond to the generator V and F – write standard to exclude all aux system equipment.
- The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.
- 30 days is too short for a response.

Based on comments received, the GVSDT revised R5 (which is now R4) to:

“R4. Each Generator Owner of an existing generating unit or generating plant shall provide an estimate of that unit’s performance during Frequency/Voltage Excursions to each requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner that monitors or models the associated generating unit or generating plant) within 60 calendar days of receipt of a written request, to ensure the accuracy of planning studies and system modeling studies. The estimate shall include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]

4.1. An estimate of the time duration the existing generating unit or generating plant will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion or a voltage excursion defined by the voltage or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant will remain connected for longer than 10 minutes, the estimate should indicate the existing unit or generating plant is not expected to trip.

4.2. Identification of the bases for the estimates developed for 4.1 which may include, but is not limited to: experience, actual event histories, or sound engineering judgment.”

Relating to Question 4: The question mistakenly referred to Requirement R5 due to changes to the standard made in response to the Quality Review. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The slight majority of stakeholders agree with the requirement while some stakeholders indicated that they do not feel the requirement is technically achievable. Based on the comments received, no major changes were made to Requirement R6 (now R5).

The GVSDT proposed voltage ride-through tables for High Voltage Ride Through (HVRT) and Low Voltage Ride Through (LVRT) time durations in Attachment 2. These tables a specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Stakeholders were asked if they agree with the proposed times in the tables. A majority of stakeholders agreed with the time values. Many of those that responded in the negative to the question indicated that they felt the 600 seconds duration was acceptable but had other concerns with the standard. No substantive suggestions were made for revising R6. As a result, the GVSDT did not make any changes to Attachment 2.

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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	David Thorne	Pepco Holdings Incand Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Pepco Holdings Inc	RFC	1, 3
2.	Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11. Chantel Haswell	FPL Group, Inc.	NPCC	5
12. David Kiguel	Hydro One Networks Inc.	NPCC	1
13. Michael R. Lombardi	Northeast Utilities	NPCC	1
14. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
15. Bruce Metruck	New York Power Authority	NPCC	6
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17. Robert Pellegrini	The United Illuminating Company	NPCC	1
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19. Saurabh Saksena	National Grid	NPCC	1
20. Michael Schiavone	National Grid	NPCC	1
21. Wayne Sipperly	New York Power Authority	NPCC	5
22. Donald Weaver	New Brunswick System Operator	NPCC	2
23. Ben Wu	Orange and Rockland Utilities	NPCC	1
24. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tino Zaragoza	IID	WECC	1
2. Jesus Sammy Alcaraz	IID	WECC	3
3. Diana Torres	IID	WECC	4
4. Marcela Caballero	IID	WECC	5
5. Cathy Bretz	IID	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Jason Marshall	ACES Power Members						X				

Additional Member	Additional Organization	Region	Segment Selection
1. James Jones	AEPCO/SWTC	WECC	1, 3, 5
2. Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Patricia Robertson	BC Hydro and Power Authority	X	X	X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Joe Spencer - SERC staff	SERC Generation Sub-committee (GS)										X
7.	Group	Tim Brown	Idaho Power - Power Production					X					
8.	Group	Jonathan Hayes	SPP Reliability Standards Develpment Team		X								

(Column headers 1–10: Registered Ballot Body Segment)

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
2.	Pat G. Harrington	BC Hydro and Power Authority	WECC	3
3.	Clement Ma	BC Hydro and Power Authority	WECC	5
4.	Daniel O'Hearn	BC Hydro and Power Authority	WECC	6

Group 6:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

Group 7:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Guy Colpron	Idaho Power	WECC	5
2.	Mark Pfeifer	Idaho Power	WECC	5

Group 8:

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clem Cassmeyer	Western Farmers	SPP	1, 3, 5
2.	Craig Henry	Oklahoma Gas and electric	SPP	1, 3, 5
3.	Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4.	Louis Guidry	CLECO	SPP	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
5.	Lynn Schroeder	Westar energy	SPP	1, 3, 5, 6
6.	Mahmood Safi	OPPD	SPP	1, 3, 5
7.	Robert Cox	Lea County Electric	SPP	
8.	Thomas Hestermann	Sunflower Electric	SPP	1
9.	Valerie Pinamonti	AEP	SPP	1, 3, 5
10.	Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5
14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

2. Louis Slade		RFC	5, 6
3. Mike Garton		NPCC	5
4. Michael Gildea		MRO	5
5. Matthew Woodzell		SERC	5

				1	2	3	4	5	6	7	8	9	10
11.	Group	Joe Spencer - SERC staff	Dynamics Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Camilletti	Santee Cooper	SERC	
2.	Sam Dwyer	Ameren Missouri	SERC	
3.	David Thompson	TVA	SERC	
4.	Robin Wells	LG&E/KU	SERC	
5.	Chris Georgeson - chair	Progress Energy	SERC	
6.	Chris Schaeffer	Duke Energy	SERC	
7.	Dale Goodwine	Duke Energy	SERC	
8.	Brad Haralson	AECI	SERC	
9.	Kumar Mani	Progress Energy	SERC	
10.	Joe Spencer	SERC Reliability Corp	SERC	

				1	2	3	4	5	6	7	8	9	10
12.	Group	Brent Ingebrigtson	LG&E and KU Energy	X		X		X	X				

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
13.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Duge	FE	RFC	5
2.	Ken Dresner	FE	RFC	5
3.	Mike Williams	FE	RFC	5
4.	Brian Orians	FE	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
14.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Rene Free	Santee Cooper	SERC	1
3.	Bridget Coffman	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	1

				1	2	3	4	5	6	7	8	9	10
15.	Group	John Seelke	Public Service Enterprise Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Mueller	PSE&G	RFC	3
2.	Ken Brown	PSE&G	RFC	1
3.	Mikhail Falkovitch	PSEG Fosssil	RFC	5
4.	Peter Doln	PSEG ER&T		6

				1	2	3	4	5	6	7	8	9	10
16.	Group	Annette Bannon	PPL Supply					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Don Lock	Lower Mount Bethel Energy, LLC	RFC	5
2.		PPL Brunner Island, LLC	RFC	5
3.		PPL Holtwood, LLC	RFC	5
4.		PPL Martins Creek, LLC	RFC	5
5.		PPL Montour, LLC	RFC	5
6.	Dave Gladey	PPL Susquehanna, LLC	RFC	5
7.	Leland McMillan	PPL Montana, LLC	WECC	5

				1	2	3	4	5	6	7	8	9	10
17.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X	X			

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	Utilities Commission, City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Lynne Mila	City of Clewiston	FRCC	3										
5. Joe Stonecipher	Beaches Energy Services	FRCC	1										
6. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4										
7. Randy Hahn	Ocala Utility Services	FRCC	3										
18.	Group	Mallory Huggins	NERC Staff Technical Review Team										
No additional members listed.													
19.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
Additional Member	Additional Organization	Region	Segment Selection										
1. Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3										
2. Chuck Matthews	BPA, Transmission Planning	WECC	1										
3. Erika Doot	BPA, Generation Support	WECC	3, 5, 6										
4. Mike Alder	BPA, Federal Hydro Projects	WECC	5										
20.	Individual	David Thompson	TVA - GO					X					
21.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
22.	Individual	Bo Jones	Westar Energy	X		X		X	X				
23.	Individual	David Youngblood	Luminant Power					X					
24.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
25.	Individual	Scott Sweat	Westinghouse					X					
26.	Individual	Antonio Grayson	Southern Company	X		X			X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
27.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
28.	Individual	Edward Cambridge	APS	X		X		X					
29.	Individual	Michael Goggin	American Wind Energy Association								X		
30.	Individual	Samuel Reed	Tri-State Generation and Transmission, Inc.	X				X					
31.	Individual	Bob Casey	Georgia Transmission Corporation	X									
32.	Individual	Hamish Wong	Wisconsin Public Service Corp			X	X	X					
33.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
34.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
35.	Individual	John Bee on behalf of Exelon	Exelon	X		X		X					
36.	Individual	Eric J Anderson	New York Power Authority	X		X		X					
37.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
38.	Individual	Tom Flynn	Puget Sound Energy	X		X		X					
39.	Individual	Jeanie Doty	Austin Energy					X					
40.	Individual	Michael Falvo	Independent Electricity System Operator		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
41.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
42.	Individual	James R. Keller	We Energies			X	X	X					
43.	Individual	Linda Horn	We Energies			X	X	X					
44.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
45.	Individual	Michael Brytowski	Great River Energy	X		X		X	X				
46.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
47.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
48.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
49.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
50.	Individual	Kathleen Goodman	ISO New England Inc.		X								
51.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
52.	Individual	Brad Jones	Luminant Energy						X				
53.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
54.	Individual	Kirit Shah	Ameren	X		X		X	X				
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
56.	Individual	Larry Grimm	Texas Reliability Entity										X
57.	Individual	Anthony Jablonski	RFC										X
58.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
59.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
60.	Individual	Gary Chmiel	GE Energy										
61.	Individual	Barry J Skoras	PPL Electric Utilities	X									
62.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
63.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
64.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
65.	Individual	Armin Klusman	CenterPoint Energy	X									
66.	Individual	Dan Hansen	GenOn Energy					X					

1. There are two new terms proposed in this standard. “Frequency Excursion” and “Voltage Excursion”. The former defined as an exceedance of system frequency beyond a continuous operating band; 60±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; ±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain.

Summary Consideration: Stakeholders were evenly divided regarding the proposed definitions. The majority of “No” votes disagreed with the voltage excursion portion of the question while there was only one vote disagreeing with the frequency excursion portion.

After reviewing all comments the SDT made the following changes:

1. **The two new terms proposed in the standard were removed. The voltage and frequency excursion values are now located in the requirements where they apply.**
2. **Attachment 1 (Off Nominal Frequency Capability Curve) was revised to clarify the “no trip” zone.**
3. **Attachment 2 (Voltage Ride-Through Time Duration Curves) has been clarified. The per unit voltage base for these curves is the base voltage specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission Systems at the point of interconnection to the Bulk Electric System (BES). In addition, the definition was modified to include the phrase, “voltages in the curve assume minimum phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum phase-to-ground or phase-to-phase voltage for the high voltage duration curve.”**

Organization	Yes or No	Question 1 Comment
Occidental Chemical	Negative	1. There are two new terms proposed in this standard. “Frequency Excursion” and “Voltage Excursion”. The former defined as an exceedance of system frequency beyond a continuous operating band; 60Â±0.5 Hertz. The latter defined as an exceedance of system voltage beyond a continuous operating band; Â±5% of scheduled voltage. Do you agree with these new terms and their definitions? If not, please explain. No: Comments: Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator’s voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team’s intent, but the definition does not clearly indicate that this is the case.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		

Organization	Yes or No	Question 1 Comment
The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	Comment (1) Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary. (2) Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **With regard to comment 1, R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.** **With regard to comment 2, R4 was revised to remove the probability of a unit (including auxiliaries) remaining connected to the system. R4 takes into consideration a voltage recovery profile at the point of interconnection using the dynamic study results from the transmission planner/coordinator. Thank you for your response. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied.**		
Pepco Holdings Incand Affiliates	No	Suggest replacing the term "scheduled voltage" with "nominal operating voltage". Voltage schedules may change over time, whereas "nominal" or "rated" voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, "rated" or "nominal" voltage.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Northeast Power Coordinating Council	No	Any requirement that requires reporting based on a deviation greater than a specified threshold, that threshold should be included in that requirement, refer to R5 as an example. With those stipulations, those

Organization	Yes or No	Question 1 Comment
		new terms are not needed.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
SERC Generation Sub-committee (GS)	No	The SERC generation sub-committee (GS) believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to "... exceedance of system voltage beyond the applicable voltage schedule."
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Idaho Power - Power Production	No	Basing the voltage excursion definition on scheduled voltage is troublesome, as "scheduled" voltage can change over time, and in some cases, varies seasonally. Protection and limiter settings are not, and should not, be adjusted to address varying schedules. That said, simply using nominal voltage instead of scheduled voltage is probably not the answer either, as it is not unusual to have POI scheduled voltages of 1.05 pu or higher.
Response: Thank you for your comments. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.		
SPP Reliability Standards Develpment Team	No	We believe that +-5% is ok for normal operating conditions but this doesn't address contingencies being taken or a time frame. The curve in attachment 2 doesn't seem to correspond with the definition as proposed. We are also unclear about the term continuous. We think this means from 0 to infinite. This graph indicates at 600s one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria shows that during a contingency we can operate at a +5% -10% bandwidth.
Response: Thank you for your comments. **The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that**		

Organization	Yes or No	Question 1 Comment
they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **The standard was not intended to apply to contingency operations.**		
Dynamics Review Subcommittee	No	Exceedance implies that the frequency is greater than desired frequency. Since the intent is to identify frequencies greater or less than a specified amount from the desired frequency, replacing the word “exceedance” with “deviation” and “beyond” with “outside” seems more appropriate.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The frequency chart was revised to clarify the “no trip” zone.		
Santee Cooper	No	We’re not sure these definitions serve a useful purpose, since, later on in the standard, these excursions are defined by the curves in the attachments.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
NERC Staff Technical Review Team	No	NERC staff believes it is unnecessary to define these terms to achieve the reliability objective of this standard. We further note that the proposed definitions of these terms are in conflict with usage of the phrases frequency excursion and voltage excursion in other standards and a defined glossary term. A review of existing NERC standards and the NERC glossary identifies the following inconsistencies:(1) Standard BAL-003-0.1b “requires a Balancing Authority to analyze its response to frequency excursions as a first step in determining its frequency bias setting.” Events identified for use in analyzing and setting requirements for frequency response are associated with frequency deviations of less than Â±0.5 Hz, and not necessarily deviating from 60 Hz.(2) Standard EOP-004-1 requires reporting for “any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in sustained voltage excursions equal to or greater than Â±10%.”(3) Standard PRC-006-1, refers to “system frequency excursions below the initializing set points of the UFLS program.” The initializing setpoints of UFLS programs vary by region.(4) The defined term, Disturbance Monitoring Equipment, includes “Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz - 3 Hz) oscillations and abnormal frequency or voltage excursions.”We also observe inconsistency within the draft PRC-024-1 which refers to “a Frequency Excursion defined by the curves in PRC-024 Attachment 1 and a Voltage Excursion defined by the curves in PRC-024 Attachment 2,” which is in conflict with the proposed definitions.Given the range of contexts in which the phrases frequency excursion and voltage excursion are used we believe it is most appropriate that each standard identify the excursions of interest in the context of that standard, rather than establishing defined terms with specific numerical values.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
TVA - GO	No	TVA believes that 60 HZ +/- 0.5 Hz is normal but the voltage schedule +/- 5% is not necessarily normal. The normal voltage should be consistent with VAR-002 requirements and defined by the voltage schedule for the unit. Change the verbiage to "... exceedance of system voltage beyond the applicable voltage schedule
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Westar Energy	No	We agree with the frequency excursion defined as +/-0.5Hz.We agree that Â±5% is appropriate for normal operating conditions. However, this does not address contingencies or timeframes. The SPP regional criteria allows for a +5% to -10% change from nominal voltage on load serving buses under single contingency conditions. The Voltage Ride-Through Time Duration Curve in Attachment 2 does not appear to correspond with the proposed definition. The Voltage Ride-Through Time Duration Curve in Attachment 2 indicates that at 600 seconds, one would operate within the .95 and 1.05 normal conditions. SPP's regional criteria states that we can operate at a +5% to -10% of nominal voltage on load serving buses during a contingency. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of this definition. We propose that the SDT consider defining continuous. We are unclear if continuous means from zero to infinite.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **The standard was not intended to apply to contingency operations.**		
Progress Energy	No	PE suggests using the term "exceeding" rather than "exceedance". PE furthermore believes that 60 HZ +/- 0.5 Hz is appropriate but does not agree that +/- 5% for voltage is an appropriate bandwidth for "normal". Any threshold must agree with VAR-002. Along with a clarification of what a voltage schedule is (i.e. target, bandwith).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values		

Organization	Yes or No	Question 1 Comment
are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
PacifiCorp	No	The definition for Voltage Excursion provided in the most recent draft of PRC-024-1 is closer to the definition of a voltage deviation. The Voltage Excursion definition should be modified to include a time duration component, e.g. “fast transition” of system voltage beyond the continuous operating band of Â±5% of scheduled voltage. Otherwise, a very slow voltage transition could be considered a voltage excursion if it exceeded the voltage band, thereby missing the intent of and time frames set forth in Attachment 2. A similar comment is applicable for Frequency Excursion. A transition time duration is key to the definition of both Voltage Excursion and Frequency Excursion due to the significant impact that these parameters can have on a generating facility.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The fast transition is considered with the transmission planner/coordinator performing a dynamic study that provides a voltage recovery profile.**		
Tri-State Generation and Transmission, Inc.	No	We don't think exceedance is a word. Suggest changing it to "operating outside of a continuous range of 60+/-0.5 Hz".We don't agree with using the phrase "scheduled voltage" as is staed in the question, but the actual standard uses "rated voltage" with which we do agree.
Response: The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Exelon	No	The definitions provided for Frequency Excursion and Voltage Excursion are not consistently applied throughout the Standard. Several of the uses of the term “excursion” (R1.2, R5.1, R5.2, R6, etc...) refer to the graphs in Attachments 1 and 2, which are based on time characteristics. Exelon agrees that 60 HZ +/- 0.5 Hz is reflective of a (normal) continuous operating band; however, the voltage +/- 5% is not necessarily a (normal) continuous operating band of "scheduled voltage". The "scheduled voltage" should be consistent with VAR-001 and VAR-002. VAR-001 Requirement R.4 states:"Each Transmission Operator shall specify a

Organization	Yes or No	Question 1 Comment
		voltage or Reactive Power schedule at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator."VAR-002 Requirement R.2 states:"[Unless exempted by the Transmission Operator] each Generator Operator shall maintain the generator voltage or Reactive Power output ... as directed by the Transmission Operator."Suggest that the definition for Voltage Excursion is revised to state "an exceedance of system voltage beyond (i.e., outside) nominal operating band as determined by the Transmission Operator"
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.**		
Independent Electricity System Operator	No	We generally agree with these definitions, but do not see the need to specify the band values, i.e. Â±0.5 Hertz and Â±5%, in them. The two definitions should stay clear of any specific values, which can be specified in the standard, to remain valid if and when the band values vary.
Response: Thank you for your comments. The SDT team agrees with your comment and has removed the new terms. The voltage/frequency excursion values are incorporated in the requirements that they are applied.		
Wisconsin Electric	No	The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Response: Thank you for your comments. The voltage chart (Attachment 2) may be more stringent in your region and can be modified.		
We Energies	No	The system can operate without problems within +/- 5% of nominal system voltage under normal conditions. Generator capability curves allow for continuous operation between 95% and 105% of rated voltage. Therefore, the operating band for voltage needs to be expanded beyond +/-5%, perhaps as high as +/- 10%.
Response: Thank you for your comments. The voltage chart (Attachment 2) may be more stringent in your region and can be modified.		
Duke Energy	No	We are not sure what is the purpose of the voltage excursion definition in this standard. Is excursion measured versus scheduled voltage, or equipment rating?
Response: Thank you for your comments. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the		

Organization	Yes or No	Question 1 Comment
system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
US Army Corps of Engineers	No	
Western Electricity Coordinating Council	No	WECC is requesting a regional variance to Requirement 1 that reflects the generator performance requirements of the WECC Coordinated Off-Nominal Frequency Load Shedding Plan. WECC's continuouse operations zone is between 59.4 hZ and 60.6 Hz. Therefore, WECC will need a regional definition of Frequency Excursion to be an exceedance of system frequency beyond a continuous operating band of 60Â±0.6 Hertz.
Response: Thank you for your comments. The SDT team discussed this and a regional variance has been added.		
ISO New England Inc.	No	The term “system voltage” is unclear as to where it is measured. Attachment 2 shows the curve based on voltage at the Point of Interconnection, yet R2.1 refers to voltage at the generator terminals. ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the “Point of Interconnection-Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. The time duration curve shown in Attachment 2 will need to modified to be consistent with this range for the times at and beyond 600 seconds to be consistent with this change.
Response: Thank you for your comments. **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. A transmission planner can provide a dynamic study that reflects the voltage recovery profile to be used by the generator owner to assess generator protective relay(s) operating characteristics.** **Attachment 2 may be more stringent in your region and can be modified.**		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP agrees that the continuous frequency specification is unambiguous and reasonable. However, the voltage operating specification needs to tie directly to the Transmission Operator’s voltage or Reactive Power schedule developed in compliance with VAR-001. We believe this was the drafting team’s intent, but the definition does not clearly indicate that this is the case.
Response: Thank you for your comments. **The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that**		

Organization	Yes or No	Question 1 Comment
they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Luminant Energy	No	The frequency is acceptable but the voltage band is confusing. The generator operating range is +/- 5% from rated at full load. Luminant recommends that the voltage excursion be referenced to generator rated voltage.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
Ameren	No	Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection.**		
Consolidated Edison Co. of NY, Inc.	No	Requirement 1, paragraph 1.1 requires that units remain connected, 1.1. When operating within a frequency range of 59.5 Hz to 60.5 Hz, inclusive. Yet the definitions of Frequency and Voltage Excursion could be misinterpreted to apply only to trips occurring when the frequency or voltage at the time of trip-out was outside the normal operating range. We do not believe that it was the intent of the drafting team to exempt units which might trip within the normal operating range during an event. Therefore, we propose to change the focus from Excursions outside a normal operating range to variations within and outside that normal operating range, out to specified limits (the operating envelope). We suggest that the term Frequency and Voltage Excursion be re-defined as variations follows: Frequency [delete “Excursion” add “Variation”] - an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] frequency within a planned continuous operating band, e.g., 60Â±0.5 Hertz, and beyond a planned continuous operating band to specified limits (Attachment 1). Voltage [delete “Excursion” add “Variation”] - an [delete “exceedance of system” add “unscheduled, excessive variation in BES”] voltage within a planned continuous operating band, e.g., 0.95 to 1.00 per unit, and beyond a planned continuous operating band to specified limits (Attachment 2). This definition includes certain types of specified variations: (a) Operation within an allowable normal operating bands,

Organization	Yes or No	Question 1 Comment
		such as voltage variations within an allowed Â±5% of scheduled voltage, e.g. from 0.95 to 1.00 per unit. (b) Operation within a modified scheduled operating band voltage change, such as with the range around a scheduled nominal voltage reduction during a brown-out, where the allowed voltage operating band is intentionally reduced, and (c) Operation up to limits specified and/or referenced in MOD-026. For example, voltage variations either within or outside of the scheduled operating band of 0.95 to 1.05 per unit of nominal, e.g., a 328-362 kV operating band around a 345 kV scheduled nominal voltage. We propose to change the Purpose wording (and similar wording elsewhere) as follows: Purpose: Ensure generating units remain connected during frequency and voltage [delete “excursions” and add “variations”] and ensure expected generating unit performance during frequency and voltage [delete “excursions” and add “variations”] is communicated to Reliability Coordinators, Planning Coordinators, Transmission Operators and Transmission Planners for accurate system modeling.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. **Attachment 1 was modified to clearly show the “no trip” zones. The voltage ride-through (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.** **The standard was not intended to apply to contingency operations.**		
Hydro-Quebec TransEnergie	No	Mostly, HQT's frequency and voltage curves are more stringent for generators, as the area for no trip zone is wider. However, the following points on those curves of attachment 1 and attachment 2 are too stringent and we ask to consider these modifications: o On the frequency curve, for wind or thermal generation only, the no trip zone between 0 and 5 seconds should be limited to an over frequency of 61,7 hz. o On the voltage curve, the no trip zone should be restricted as follow: ï‚§ Between 1 and 2 seconds, to 0,75 pu, ï‚§ Between 2 and 3 seconds, to 0,85 pu.
		(1) Voltage Excursion definition should be based on rated system operation voltage which is what the protection is based on, not scheduled voltage which may vary. (2) Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable.
Response: Thank you for your comments. **The frequency chart may be more stringent in your region and can be modified.** **R2 has been revised to define that *generator* protective relaying to ride through a system fault (three-phase with clearing time of 9 cycles or less) at the**		

Organization	Yes or No	Question 1 Comment
point of interconnection with the unit operating between 95% and 105% of rated voltage. Protective systems at the generator are required to not trip for a voltage excursion at the point of interconnection. **R4 was revised to remove the probability of a unit (including auxiliaries) remaining connected to the system. R4 takes into consideration a voltage recovery profile at the point of interconnection using the dynamic study results from the transmission planner/coordinator.**		
PPL Supply	Yes	1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary.2. The need for excursions as severe as those of Att.2 should be confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The chart may be more stringent for your region based on the transmission planner specifications.**		
American Electric Power	Yes	Where these definitions appear to be referenced in the standard (R5 and R6), they seem to be at odds with Attachments 1 and 2. Either the attachments should be used and remove the definitions, or instead, the definitions should be used and remove the references to the attachments in R5.1 and R5.2 and R6.We recommend removing the definition of “Frequency Excursion” and retaining Attachment 1 subject to our comments given elsewhere in this document. We recommend keeping the “Voltage Excursion” definition and eliminating Attachment 2 based on our comments elsewhere in our response.
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES.		
PPL Electric Utilities	Yes	1. The question above presents simple +/-0.5 Hz and +/-5% definitions of Frequency Excursions and Voltage Excursions respectively, but the time-related criteria in Attachments 1 and 2 are much more complex and are referenced in R6 as pertaining to the defined terms in question. Part A (Introduction) of this and all NERC standards should include a section dedicated to definition of terms used in the standard, if they are not already included in the NERC Glossary.2. The need for excursions as severe as those of Att.2 should be

Organization	Yes or No	Question 1 Comment
		confirmed. Anything beyond +/- 4 kV for our 230 kV interconnects (+/- 1.74%) would be considered abnormal for our system (PJM).
Response: Thank you for your comments. The two new terms proposed in the standard have been removed. The voltage/frequency excursion values are incorporated in the requirements that they are applied. **The voltage excursion (Attachment 2) has been further defined as the per unit voltage base specified in the system models used by the Transmission Planner in the analysis of the reliability of the Interconnected Transmission System at the point of interconnection to the BES. The chart may be more stringent for your region based on the transmission planner specifications.**		
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
MRO's NERC Standards Review Forum	Yes	
Electric Market Policy	Yes	
LG&E and KU Energy	Yes	
FirstEnergy	Yes	
Public Service Enterprise Group	Yes	
Florida Municipal Power Agency	Yes	
Arizona Public Service Company	Yes	
Luminant Power	Yes	
Westinghouse	Yes	

Organization	Yes or No	Question 1 Comment
Southern Company	Yes	
American Wind Energy Association	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Austin Energy	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
South Carolina Electric and Gas	Yes	
RFC	Yes	
Tacoma Power	Yes	
GE Energy	Yes	
American Transmission Company	Yes	

2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent.

Summary Consideration: Stakeholders agreed that footnote 1 does clearly state that a Generator Owner is not required to have protective relaying installed or set for frequency or voltage protection. Many of the stakeholders made additional comments beyond the scope of the question regarding the intention of Requirements R1, R2, and R3. In response, the SDT made the following changes:

1. The Requirement Parts were revised in Requirement R1. Part 1.5 was moved into the body of R1. The requirement now reads:

"R1. Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant shall set such protective relaying so that it does not trip within the "no trip zone" of PRC-024 Attachment 1, unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. . [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

1.1. A generating unit or generating plant is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec.

1.2. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

2. Requirement Part 2.1.1 was removed from Requirement R2. The body of the requirement and the remaining Parts were modified to clarify intent. The requirement now reads:

"R2. Each Generator Owner that has generator voltage protective relaying1 activated to trip its new or existing generating unit or generating plant shall set its protective relaying such that it does not trip as a result of a voltage excursion (at the point of interconnection) that remains within the "no trip zone" of PRC-024 Attachment 2 caused by an event on the transmission system external to the generating plant per the following operating conditions and relay settings, unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing generating unit2 or generating plant.: [Violation Risk Factor: High] [Time Horizon: Long-term Planning]

2.1. When operating within 95 percent to 105 percent of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1. If a Transmission Planner's study (based on the location specific voltage recovery characteristics) allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, set voltage relays either to meet the Transmission Planner's voltage recovery characteristics or the characteristics in PRC-024 Attachment 2.

2.1.2. Tripping a generator in accordance with a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3. If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2.

2.1.4. A generating unit or generating plant may trip if the protective functions (such as out-of-step or loss-of-field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment."

3. Requirement R3 was changed to clarify the intent of non-protection system limitations and when such limitations must be addressed. The requirement now reads:

"3.1. The Generator Owner shall communicate the documented limitation, or the removal of a previously documented limitation, to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner within 30 calendar days of identifying the limitation to ensure the accuracy of planning studies and system modeling studies. The existing generating unit or generating plant becomes subject to the full extent of Requirements R1 and R2 coincident with either of the following conditions:

- **The equipment causing the limitation is repaired or replaced with equipment that removes the limitation.**
- **The equipment causing the limitation is modified or upgraded resulting in an increase of generator nameplate capacity rating greater than 10 percent (cumulative from the first effective date of this Standard)."**

Organization	Yes or No	Question 2 Comment
PacifiCorp	Negative	(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without

Organization	Yes or No	Question 2 Comment
		the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).** (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.** (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to PRC-024 Attachment 2. 2.1.3 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" in PRC-024

Organization	Yes or No	Question 2 Comment
		Attachment 2. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2. **The SDT has revised the wording in the subsections of Requirement R2 to make the intent clearer. Section 2.1.1 has been removed. Section 2.1.3 now says "Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2." Section 2.1.4 now says" If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."** (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has modified PRC-024 Attachment 1 to accommodate the WECC regional requirements.**
Response: Thank you for your comments. See specific responses above.		
Occidental Chemical	Negative	2. Requirements R1 and R2 detail the required frequency and voltage protective relaying settings for both new and existing units or generating plant/facilities that opt to activate these relays. Does the current draft of these two requirements, including footnote 1, clarify that a Generator Owner is not required to have protective relaying installed or set for these functions? If you do not believe the requirement is clear, please provide alternative language to clarify the intent. No: Comments: Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. For the record, R2 seems to be more logically constructed - and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1.
Response: Thank you for your comments. The SDT has removed the subparts of Requirement R1. The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024		

Organization	Yes or No	Question 2 Comment
Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement. It now says" Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility shall set such protective relaying not to trip per PRC-024 Attachment 1 unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."		
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	4)Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. **The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024 Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement. The wording now states: "Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."** (5)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific conditions of the SPS or RAS schemes? **The SDT agrees that the generators would be allowed to trip in the no trip zone for the specific condition of a SPS or RAS scheme and believes the existing wording conveys that intent.**
Response: Thank you for your comments. See specific responses above.		
Lower Colorado River Authority; Platte River Authority; Snohomish County PUD No. 1	Negative	o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to**

Organization	Yes or No	Question 2 Comment
		accommodate regional variations in WECC and the Quebec Interconnection. o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. **Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? o **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.**
Response: Thank you for your comments. See specific responses above.		
Black Hills Corp	Negative	As drafted R1 confilists with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan) and could potentially result in a negative reliability impact if enforced in the Western Interconnect. **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of R2, part 2.1.1 is confusing and needs to be clarified. **The wording of Requirement R2, part 2.1.1 had been removed.**
Response: Thank you for your comments. See specific responses above.		
Avista Corp.; BrightSource Energy, Inc.; Chelan County Public Utility District #1; City of Farmington; City of Redding; Colorado Springs Utilities; City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Cogentrix Energy, Inc.; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; Salt River Project; South California Edison Company; Tacoma Public	Negative	As drafted, Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements as identified in the WECC Off-Nominal Load Shedding Plan must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. **The wording of Requirement R2, part 2.1.1 had been removed.**

Organization	Yes or No	Question 2 Comment
Utilities; Western Area Power Administration; Western Electricity Coordinating Council; Seattle City Light		
Response: Thank you for your comments. See specific responses above.		
MEAG Power	Negative	Comment o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Â Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan.Â This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion.Â Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2"Â a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan.Â Â **Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. Â However language for zone 1 faults sets to remove the generator before 9-cycles. **The wording of Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection Â system equipment limitations exemption expiration for upgrades of Â =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.** o The response content for R4 is ambiguous regarding what the written response should contain. **The SDT has removed Requirement R4.** o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping? **A note has been added to PRC-024 Attachment 1 to indicate that tripping is allowed on the lines.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. See specific responses above.		
Orlando Utilities Commission; Snohomish County PUD No. 1	Negative	Comment o The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards. Requirement R1 mandates the generator off-nominal frequency to requires that the GO to set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** o With respect to the R2.1 requirement, it appears the intent is to not trip the generator and remain interconnected through the voltage excursion. However language for zone 1 faults sets to remove the generator before 9-cycles. **The wording of Requirement R2, part 2.1.1 had been removed.** o Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.** o The response content for R4 is ambiguous regarding what the written response should contain. **The SDT has removed Requirement R4.** o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping? **A note has been added to PRC-024 Attachment 1 to indicate that tripping is allowed on the lines.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Pool	Negative	Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or

Organization	Yes or No	Question 2 Comment
		protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? **The SDT agrees and has revised the wording in the footnote to clarify the intent.** In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? **Requirement R2 has been revised to clarify that it is generator protective relaying. Auxiliary systems are not included.** The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". **Protective relays are one element in a protection system. The SDT does not believe there is an inconsistency.**
Response: Thank you for your comments. See specific responses above.		
Muscatine Power & Water	Negative	In Requirement 1, Requirement 2 and footnote 1 it is not clear because control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under Requirement 3, which covers equipment limitations either. **The SDT agrees and has revised the wording in the footnote to clarify the intent.** For Requirement 5, if design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements. **The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.**
Response: Thank you for your comments. See specific responses above.		
Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District	Negative	We commend the drafting team's efforts with the Verification of Models and Data for Generator Excitation and Control System Functions and Plant Volt/VAr Control Functions. However, the following comments regarding PRC-024-1 are currently prohibiting an affirmative position: Requirement R1 mandates the generator off-nominal frequency to requires that the GO set the protective relays such that they will not trip the generator within the no-trip zones defined by the curves in PRC-024 Attachment 1 without regard for the interconnecting entities' regional off-nominal plan. This may include coordination of load shedding blocks & load restoration blocks and other off-nominal efforts including generation tripping plans that should be left to the interconnecting entity's discretion. Similar to the exception criteria for the voltage excursion of R2.1.2 " If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set the voltage relays either to the

Organization	Yes or No	Question 2 Comment
		Transmission Planner's settings or the settings in PRC-024 Attachment 2" a similar exception should be made where the generator facility interconnects to an entity that has established and incorporated an off-nominal frequency plan. Clarification for allowable tripping options of points on the Attachment 1 curve other than the 59.5 Hz and 60.5 Hz values are necessary. **The posted curves in PRC-024 Attachment 1 match PRC-006 Attachment 1 expectations for generator tripping. Modifications to PRC-024 Attachment 1 have been made to accommodate regional variations in WECC and the Quebec Interconnection.** The language of Requirement R2, part 2.1.1 is confusing and needs to be clarified. According to Attachment 1 capable generators are required to stay connected at a minimum for 9 cycles for the zone 1, three phase faults. Regarding sub-requirement 2.1.1. where: for three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, not to exceed 9 cycles. This appears to be addressing clearing times for the transmission elements and is not applicable to the generator owner. As PRC-024-1 is only applicable to the GO, either the applicability needs to be expanded to include the TO or sub-requirement 2.1.1 needs to be struck from PRC-024-1 and considered to be included in another standard. **The wording of Requirement R2, part 2.1.1 had been removed.** Regarding generator's non-protection system equipment limitations exemption expiration for upgrades of =10%, would the re-exemption status be allowed or does the upgrade require removal of the limitation? **The intent is that the Generator Owner would have to replace, repair, or modify any equipment causing a technical limitation if the capacity of the generating unit were increased by 10% or more.**
Response: Thank you for your comments. See specific responses above.		
Pepco Holdings Incand Affiliates	No	Footnote 1 does make it clear that the Generator Owner is not required to have frequency or voltage protective relaying. However, in the current draft, reference to footnote 1 appears to have been inadvertently omitted following the phrase "voltage protective relaying" in R2.
Response: Thank you for your comments. A reference to Footnote 1 has been added to Requirement R2.		
SPP Reliability Standards Develpment Team	No	We agree that R1, with the footnote mentioned, makes it clear that the Generator owner would not be required to have protective relaying installed or set for these functions. As for R2 we feel that footnote 1 should also be referenced in R2.
Response: Thank you for your comments. A reference to Footnote 1 has been added to Requirement R2.		
MRO's NERC Standards Review Forum	No	The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or

Organization	Yes or No	Question 2 Comment
		not. This does not seem to be covered under R3 which covers equipment limitations either.
Response: Thank you for your comments. Footnote 1 has been revised to clarify that "…protective functions within control systems that directly trip the generator…" are included. Requirement R3 discusses the limitations of the generating equipment exclusive of protective functions, whether they are protective relays or protective functions in a control system.		
Electric Market Policy	No	The question is confusing because of the phrase "set for these functions." The language in Requirements R1 and R2 as well as footnote 1 suggest that GOs are not required to have the specific relays "installed or activated on its units. If however, the relays are activated then they are required to be "set" pursuant to the standard.
Response: Thank you for your comments. The SDT agrees that the question could have been worded more clearly, but it appears that you understood the intent.		
Dynamics Review Subcommittee	No	It is unclear how an entity can have protective relaying settings for new units. Since "existing units" covers units under construction as specified in footnote 2, "new" implies planned units and thus the associated relaying would also be "planned" not "existing." It appears the word "new" should be deleted from sentence one of R1 and sentence one of R2.
Response: Thank you for your comments. Requirements R1 and R2 apply to both new and existing units. New units (designed, built and operated after Requirement R5 is implemented) must set any protection system functions that are installed and activated so that they meet these requirements.		
LG&E and KU Energy	No	Comments: LG&E and KU Energy recommends the wording be changed for R1/R2 to "Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following..."Or, change from "Each GO" to "GO's that have frequency and voltage protection functions activated to trip a new/existing generation unit."
Response: Thank you for your comments. The SDT has changed the wording to clarify the intent. Requirement R1 now states, in part: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility…". Requirement R2 now states, in part: "Each Generator Owner that has generator voltage protective relaying Error! Bookmark not defined.** **activated to trip its new or existing unit or generating plant or generating Facility…".**		
Santee Cooper	No	The sub-requirements of R2 could be read as prescribing exactly where you have to set this relaying. Often our relay set points originate with the OEM and are based on protecting the Generator and Turbine. The finalized curves that originate here should be used as a means to arrive at those settings, but, as long as the settings do not cause the relaying to operate for the ranges in the finalized curves, the requirements should

Organization	Yes or No	Question 2 Comment
		be satisfied (It shouldn't have to be stated that you can set them less stringent, if you can not have the relaying entirely).
Response: Thank you for your comments. The SDT has defined a "no trip zone" for voltage excursions at the generator's point of interconnection. As with any other exercise in relay coordination, it is up to the Generator Owner to determine how much margin to allow when determining the settings of the protection system.		
Florida Municipal Power Agency	No	The term "protective relaying" is confusing in two ways: 1) the footnote is ambiguous as to how it applies; and 2) it calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005 (especially when considering the inconsistent use of "non-protection system equipment" in R3). FMPA suggests the term "safeguard" instead of "protection", e.g., a "frequency safeguard system" to avoid this ambiguity and with a footnote to make more clear that systems like GE Mark VI's are or are not included.Similarly in R2, it is unclear what "voltage protective relaying" is. FMPA suggests using the word "safeguard" instead of "protection". **The word "safeguard" has specific implications to nuclear plants and is not generally used in industry as a substitute for the word "protection".** Also, it is unclear whether station service voltage safeguards are included, such as motor contactors. **For Requirements R1 and R2, the station service system is not included in the scope. However for new facilities, Requirement R5, states that the facility must ride through the excursions, so the station service system would have to be designed and built to achieve this goal.** In addition, "external to the plant" as used in several requirements (e.g., R1, R2 and R6) is ambiguous. We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system". **Requirement R1 does not use the words "external to the plant". Requirements R2 and R6 have been revised and now state, in part: " …caused by an event on the transmission system external to the plant…"**
Response: Thank you for your comments. See specific responses above.		
Bonneville Power Administration	No	R2.1.1 - Please clarify/verify: o That the allowable voltage relay trip time is greater than the normal fault clearing time up to a normal clearing time of 9 cycles; **The SDT agrees.** o That tripping is allowed above 9 cycles regardless if it is normal clearing or backup clearing; and, **The SDT agrees.** o That for generators in close proximity the normal clearing time is coordinated to ensure it is no greater than what a specific generator was designed to withstand. **This standard does not specify requirements for the transmission protection system. This coordination should be accomplished through compliance**

Organization	Yes or No	Question 2 Comment
		with NERC standard PRC-001-1.
Response: Thank you for your comments. See specific responses above.		
Progress Energy	No	Requirement R1 subsection 1.5 is not clear as to when rate tripping is acceptable or not. Is it OK to trip at 59.6 Hz if the ROC is > 2.5 Hz or is this ROC trip acceptable only outside the no trip zone.
Response: Thank you for your comments. The intent is that tripping is allowed if the frequency rate of change exceeds 2.5 Hz/sec even if the absolute frequency is within the "no trip zone" defined in PRC-024 Attachment 1. The wording in Requirement R1 has been revised to clarify the intent. It now states, in part: "…Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."		
Exelon	No	Footnote 1 should be added to the Applicability section of the Standard. Suggest that the Applicability section be revised to state "GO shall set applicable protective relaying so as not to impact R1.1, R1.2, R1.3, R1.5, unless exempted by a non-protection system equipment limitation per the exclusion criteria in Requirement R3."
Response: Thank you for your comments. The SDT disagrees that this wording should be added to the Applicability section.		
Puget Sound Energy	No	Please clarify whether rate of change of frequency relaying is required; or alternatively, if the required setting of not less than 2.5 Hz/sec is only applicable IF rate of change of frequency elements are available and enabled.
Response: Thank you for your comments. The SDT believes that Footnote 1 clearly states that the Generator Owner is not required to install or activate any frequency or voltage protection. This would include rate of change of frequency functions. If the Generator Owner does have frequency rate of change protection installed and activated, then it must be set to meet the Requirement R1.		
Great River Energy	No	The requirement and footnote is not clear in that control algorithms incorporated in plant control systems that effectively limit speed and therefore frequency are not clearly identified as being covered by the standard or not. This does not seem to be covered under R3 which covers equipment limitations either. **Footnote 1 has been revised to clarify that control systems are included if they will trip the generator.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments.		
Ingleside Cogeneration LP	No	Requirement R1 from Ingleside Cogeneration's perspective could lead to a double-infraction for the same incident. For example a single improper relay operation for an underfrequency transient would lead to a violation of both R1.2 and R1.3. It should be sufficient to specify that relays must be set in conformance with the off-frequency excursions provided in PRC-024 Attachment 1. **The SDT has removed the subparts of Requirement R1.** Also, there must be some logical limit to the Hz/Second ride-through threshold specified in R1.5. As the requirement is written, even a large-magnitude frequency transient must not cause relays to operate as long as the frequency rate of change is slow. If for example, the interconnection frequency dropped to 55 Hz at a rate lower than 2.5 Hz/Second, R1.5 seems to require that the generator would remain connected to the BES. **The intent of part 1.5 of Requirement R1 was to allow tripping if the rate of change of frequency exceeded 2.5 Hz/sec, even if the absolute frequency were still within the No Trip Zone of PRC-024 Attachment 1. The wording has been revised to clarify the intent and incorporated into the body of the Requirement which now states, in part: "Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec."** For the record, R2 seems to be more logically constructed - and lists reasonable exceptions to voltage relay settings. Ingleside Cogeneration LP recommends the drafting team to take a similar approach on R1. **The SDT has revised the wording in Requirement R1, which now states: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility shall set such protective relaying not to trip per PRC-024 Attachment 1 unless the Generator Owner has documented and communicated each equipment limitation in accordance with Requirement R3 for an existing generating unit. Additionally, the generator is allowed to trip within the "no trip zone" if the frequency rate of change is more than 2.5 Hz/sec".**
Response: Thank you for your comments. See specific responses above.		
Luminant Energy	No	Recommended that in the Footnote and in R1 indicate generator protective relaying.
Response: Thank you for your comments. The word "generator" has been added as a modifier to "protective relay" in Requirement R1.		
PPL Electric Utilities	No	Recommend the wording be changed for R1/R2 to " Each GO shall set the generator frequency protective relaying, if installed, not to trip during the following..."

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. The SDT has changed the wording to clarify the intent. Requirement R1 now states, in part: "Each Generator Owner that has generator frequency protective relaying activated to trip its new or existing generating unit or generating plant or generating Facility…". Requirement R2 now states, in part: "Each Generator Owner that has generator voltage protective relaying Error! Bookmark not defined.** **activated to trip its new or existing unit or generating plant or generating Facility…".**		
Indiana Municipal Power Agency	No	The term "protective relaying" is confusing in a two ways: 1) The footnote needs to clarify how it applies; and 2)the term calls into question whether this is a "generation Protection System" applicable to PRC-004 and PRC-005. **The SDT has revised the standard to use the term generator protection system. This standard does not define the scope of applicable equipment in other NERC standards.** It needs to be made more clear that systems like the GE Mark IV and VI control systems are or are not included. **Footnote 1 has been revised and now states, in part: "…or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs) installed or activated on its unit".** R2 is also not clear when using "voltage protective relaying". It is not clear if voltage safeguards on motor contactors are included. **For Requirements R1 and R2, the station service system is not included in the scope. However for new facilities, Requirement R5, states that the facility must ride through the excursions, so the station service system would have to be designed and built to achieve this goal.** The standard also needs to make more clear what "external to the plant" exactly means. **The words "… on the transmission system…" have been added to clarify the intent.**
Response: Thank you for your comments. See specific responses above.		
Alliant Energy Corp. Services, Inc.	Affirmative	While we are voting affirmative on this ballot, we have 2 comments concerning the standard: 1. Standard needs to be clarified such that it is clear whether the no trip zones include or exclude the lines that define the curves. **The SDT has added a note to PRC-024 Attachments 1 and 2 to indicate that the "no trip zones" do not include the lines that define the curves.** 2. R1 - uses the defined term of protective relaying which for other PRC standards does not include excitation controls such as PRC-005, yet there is a footnote attached to the term "protective relaying" that includes excitation controls which trip generators. This can cause confusion on the interpretation of whether controls that trip are considered a protective relay. R1 should be redrafted to state protective relaying and excitation controls instead of attaching a footnote which redefines what in inclusive in the term "protective relaying". **The SDT believes (in consultation with the Protection System Maintenance and Testing SDT) that protection functions in control systems that directly trip a generator are within the scope of PRC-005.**

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. See specific responses above.		
SERC Generation Sub-committee (GS)	Yes	The GS recommends that the applicability section be revised from "GO" to "GO's that have frequency and voltage protection functions activated to trip a new/existing generation unit." **The SDT disagrees that this wording should be added to the Applicability section.** Also, while the GS does, in general, agree with the content of footnote #2 on page 2 (under R1), we believe that this is verbiage is better placed in the implementation plan because it puts commercial considerations into the standard. **The SDT disagrees that this wording would be better placed in the Implementation Plan.**
Response: Thank you for your comments. See specific responses above.		
Idaho Power - Power Production	Yes	Yes, R1 and R2 do make it clear that the GO does not have to install or set these functions however we believe that the standard should clarify better that the standard is applicable to all "voltage-based" protection functions such as the backup impedance function (21) and the voltage controller (51C) or voltage restrained (51V) Overcurrent functions. These functions may operate if not coordinated properly. We do not believe that was made very clear. **The SDT agrees and has revised Footnote 1 to read, in part: "… relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices…"** Particularly for units that fully compliant with this standard, providing an estimate of unit performance during a frequency or voltage excursion is burdensome and unnecessary. If the event is within the parameters of the standard, the planner can rely on the unit staying on, if not, the planner should model the unit as a trip. In particular, we are unaware of any methodology that would be capable of providing an "estimated probability". Protection consistently operates as designed and configured. **The SDT agrees that the "estimated probability" does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	A one-sentence statement should be added stating that the protective relays affected by this standard are only the generator protective relays, not any other relays for the unit and/or facility.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. The word "generator" has been added in Requirement R1 to clarify the intent.		
Southern Company	Yes	1) The footnote is clear, however, the exact meaning of the phrase "non-protective system equipment" limitation in R1 and R2 is not clear. Does this exclude any equipment limitation that is protected by a protective relay? Does this allow tripping using protective relays that are protecting a turbine from underfrequency conditions or a generator or transformer from excessive volts-per-hertz conditions? We feel that a fundamental tenant of reliability includes adequately protecting generating plant equipment from detrimental conditions - a generator owner needs to be allowed to protect its equipment from possible damaging consequences of off-nominal voltage and frequency. **The SDT agrees that protection of generating plant equipment is fundamental. The meaning of the phrase "non-protection system equipment" is that limitations of the protection system itself cannot be used as an exemption from meeting Requirements R1 and R2.** 2) We believe examples of "non-protection system equipment" include, but are not limited to, turbine generators, transformers, feed pump systems/controls, boiler control systems, reactor protection systems, emergency diesel generators, AC motors, pumps, fans, AC motor contactors, auxiliary relays, etc. **The SDT agrees.** 3) Nuclear stations have an approved Setpoint Methodology which governs the process of determining and documenting setpoints for the equipment at that station. This methodology will incorporate some margin between the expected operating condition and setpoint actuation to help ensure proper operation of the unit but provide the necessary protection as well. How was this considered in the development of this standard? **Standard coordination methodologies apply. If "proper operation of the unit" to meet NRC or other nuclear safety needs requires tripping within the No Trip Zone of either PRC-024 Attachment 1 or Attachment 2, this would be considered a legitimate technical limitation.**
Response: Thank you for your comments. See specific responses above.		
American Electric Power	Yes	Although the footnote is worded somewhat awkwardly, it is clear that a Generator Owner is not required to have protective relaying installed or set for these functions. Suggest using "Generator Owners are not required to have... installed or activated on their units". **Thank you for your comments. The SDT has decided to retain the existing wording.**
PacifiCorp	Yes	
American Wind Energy	Yes	

Organization	Yes or No	Question 2 Comment
Association		
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Dynegy Inc.	Yes	
Austin Energy	Yes	
Independent Electricity System Operator	Yes	
Wisconsin Electric	Yes	
We Energies	Yes	
We Energies	Yes	
Xcel Energy	Yes	
South Carolina Electric and Gas	Yes	
Duke Energy	Yes	
US Army Corps of Engineers	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 2 Comment
ISO New England Inc.	Yes	
Ameren	Yes	
RFC	Yes	
Tacoma Power	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
GE Energy	Yes	
American Transmission Company	Yes	
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
ACES Power Members	Yes	
BC Hydro and Power Authority	Yes	
NERC Staff Technical Review Team	Yes	
TVA - GO	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 2 Comment
Luminant Power	Yes	
Westinghouse	Yes	

3. **Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language.**

Summary Consideration: The question, in error, contained a reference to R4 rather than R5. As this question is in error, the drafting team will ask this question on the next posting. Some commented as if the question was really about R4, while most commented as if the question was about R5.

Summary of the R4 comments: Either the specific details of the response required by R4 is needed or R4 is not needed due to no reliability impact.

Summary of the R5 comments:

Many entities (8) feel that there is no additional reliability gain in this requirement - the information is not useful - there is little value technically of this information.

Others (5) expressed that it is very difficult, if not impossible, to predict the consistent response of the balance of (a generating) plant to the system excursions shown in Attachment 1 & 2.

Further, 10 companies expressed that it is unlikely that any steam plants will survive for the entire "no trip zones" of the attachments.

Other, less frequent, opinions included the following:

- **R1-R4 adequately fulfill the purpose of the standard.**
- **Standard requirements should be limited to devices that directly respond to the generator V and F – write standard to exclude all aux system equipment.**
- **The TP needs only to know when the protective relaying V-t and F-t will trip the unit so the models can switch the generators off when the simulated V and F levels are reached.**
- **30 days is too short for a response.**

Organization	Yes or No	Question 3 Comment
PacifiCorp	Negative	(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity

Organization	Yes or No	Question 3 Comment
		and clarity included in MOD-026, Requirement R3.
Response: Thank you for your comments The SDT has removed Requirement R4.		
Occidental Chemical	Negative	3. Requirement R4 has been added for owners of existing units or generating plant/facilities to provide an estimate of the performance of the units during frequency and voltage excursions. This information is intended to provide Transmission Planners with information useful in performing planning studies. Do you agree with this approach? If not please explain and provide alternative language. No: Comments: Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District	Negative	In Requirement 4, the response content is ambiguous regarding what an acceptable response should contain. Consider requiring the response to be similar to the MOD-026-1 R3 response that identifies a technical basis.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Luminant Energy	Negative	R5 would still be required but the study would only involve fault conditions that have trip times less than 45 cycles.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Black Hills Corp	Negative	Suggest rewrite R4 to add specificity as to what must be included in the required written response, similar to

Organization	Yes or No	Question 3 Comment
		the specificity & clarity included in MOD-026, R3.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Lower Colorado River Authority; Platte River Authority; Snohomish County PUD No. 1	Negative	The response content for R4 is ambiguous regarding what the written response should contain. o Other than the R1.1 frequency range of 59.5 Hz and 60.5 Hz, are the other points of the curve of Attachment 1 allowable points for tripping?
Response: Thank you for your comments. The SDT has removed Requirement R4. The SDT has added a note to PRC-024 Attachment 1 to indicate that the lines that define the curves are allowable tripping points.		
Avista Corp.; BrightSource Energy, Inc.; Chelan County Public Utility District #1; City of Farmington; City of Redding; Colorado Springs Utilities; City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Cogentrix Energy, Inc.; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; Salt River Project; South California Edison Company; Tacoma Public Utilities; Western Area Power Administration; Western Electricity Coordinating Council; Seattle City Light	Negative	We suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity included in MOD-026, Requirement R3.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Pepco Holdings Incand Affiliates	No	Believe this question is referring to Requirement R5 not R4 as stated in the question. Not sure how useful the R 5.2 probability assessment would be, therefore suggest eliminating that requirement. R 5.1 coupled with the basis requirement in R 5.3 would appear sufficient to quantitatively assess the performance during voltage

Organization	Yes or No	Question 3 Comment
		and frequency excursions. Also, see responses to question #6.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Northeast Power Coordinating Council	No	The reference to “R4” in this question should be R5.
Response: Thank you for your comments. The SDT agrees.		
ACES Power Members	No	Requirement R4 references inquiries regarding equipment limitations that have been identified in R3. This particular question should apply to R5 instead. If applied to R5, the approach in theory seems reasonable.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. Requirement R5 retains the obligation of the Generator Owner to evaluate the time that a generating unit or facility will remain connected following an excursion that is defined by the Transmission Planner.		
BC Hydro and Power Authority	No	The requirement R5 (R4 is a typo in the Question) is ambiguous and redundant. What does “estimating” mean? One could infer that the GOs are actually required to do what TPs are normally doing as part of their studies: estimating (assessing, simulating) the performance of units during frequency or voltage excursions.In order to fulfill requirements R1, R2 and R3 of this standard, GOs have to do engineering analysis and studies to develop adequate protection settings and to assess other non-protection systems and equipment. By declaring compliance GOs commit to keeping their units on-line during defined frequency or voltage excursions. In the case that a GO identifies a particular limitation, they would inform the TPs so that this limitation is taken into account in system studies. Hence, the goal of the standard would be fully met without R5. In light of the above, the requirement R5 should be removed. Technically it is of little value, if any, becoming just an unnecessary burden for GOs. In compliance terms it could be a source of perpetual confusion and disputes.
Response: Thank you for your comments. As stated in the Requirement, the estimate is to be based on experience, event histories, or sound engineering judgment. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		

Organization	Yes or No	Question 3 Comment
SERC Generation Sub-committee (GS)	No	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
Response: Thank you for your comments. The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.		
Idaho Power - Power Production	No	
SPP Reliability Standards Develpment Team	No	The question should mention R5 and not R4. We feel like the planners shouldn't have to request this data and should be supplied for each unit once and again if the characteristics change. We also feel like 30 days might not be appropriate time to gather such information and would suggest that 90 days would be a better time frame for supplying this data.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Electric Market Policy	No	Requirement R4 seems to be duplicative of the obligation to notify the same entities under Requirement R3. Perhaps the language in R4 could be clarified to indicate the distinction.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
LG&E and KU Energy	No	: LG&E and KU Energy agrees with the approach but recommends 60 days. Moreover, this appears to be R5, not R4.
Response: Thank you for your comments. The SDT agrees and has changed the time to 60 days.		
Santee Cooper	No	It should be ascertained how and if the TP will use this in TPL-001 analysis. It will be unclear how to demonstrate compliance.
Response: Thank you for your comments. The Requirement is written for the Generator Owner to respond to the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner). If these entities do not want this information, they are not required to request it.		

Organization	Yes or No	Question 3 Comment
PPL Supply	No	1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5.2. The question above cites "frequency and voltage excursions [emphasis added]," the question 4 below deals with "frequency or voltage excursions," para. R5.1 states "Frequency Excursion...and a Voltage Excursion" and para. R6 references "Frequency Excursion or Voltage Excursion." The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. **The SDT has revised section 5.1 to indicate that the frequency excursion and/or voltage excursion are to be defined by the Transmission Planner.** 3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. **The SDT disagrees. Standards MOD-026 and MOD-027 require verification of the excitation and frequency control responses, but do not discuss the ability of a generating unit or facility to remain connected to the grid.** 4. In the event that R5 remains as-is, a standard-specific definition of the word "plant" is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit's behavior. **The applicability of this standard is to generating units and facilities that meet the NERC Registry Criteria.** 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024. **The SDT expects the Generator Owner to estimate as best as he can the performance of the entire unit or facility based on past experience, event histories, or sound engineering judgment as described in the requirement.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Agency	No	R4 is missing the VRF and Time Horizon. FMPA recommends "Lower" and "Long-term Planning".
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Bonneville Power Administration	No	R3-R4 - Generator Owners may be unwilling to share proprietary information in response to requests from Reliability Coordinators, Planning Coordinators, Transmission Operators, or Transmission Planners, because of manufacturer restrictions or for other reasons. Should the standard anticipate this issue?

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. The SDT has removed Requirement R4.		
TVA - GO	No	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator.
Response: Thank you for your comments. The SDT agrees and feels the comment is a good statement of the rationale for this Requirement. The information provided by the Generator Owner for modeling his facility based on experience, past event histories, or good engineering judgment will allow better modeling of the performance of the facility.		
Arizona Public Service Company	No	AZPS believes this question applies to R5. In any event, this requirement does not add anything to the reliable modeling since most GO(s) will be making a guess, and that does not make the simulation any more accurate.Additionally, the requirement for providing this information within 30 days is unreasonable. It should be at least 90 days. There is no reliability reason for requiring this data within 30 days. These are long range planning studies and modeling data is usually submitted on the annual basis.
Response: Thank you for your comments. The Requirement is written for the Generator Owner to respond to the requesting entity (Reliability Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner). If these entities do not believe the information will be of value, they are not required to request it. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Westar Energy	No	This question better addresses R5 rather than R4. We propose that the SDT team consider revising the 30 day requirement to provide documentation of the equipment limitation to 90 days in R5. We recommend that 90 days is a more appropriate timeframe for supplying this documentation.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		
Luminant Power	No	Luminant believes this standard should only apply to voltage and frequency relay settings.
Response: Thank you for your comments. The SDT disagrees. Restricting the scope to the protection system settings would not meet the intent of FERC Order 693.		
Progress Energy	No	This appears to actually refer to R5. PE submits the comments below with the assumption that this question is directed toward R5:PE agrees with the requirement of R5 in general, but disagrees with the approach to the extent that R5.1 contains two options for GOs' providing of information regarding voltage excursions, one of

Organization	Yes or No	Question 3 Comment
		which is problematic. Specifically, the requirements of Attachment 2 are too stringent and cannot be used by the majority of GOs, which leaves the second option as the only feasible method. The second option, provision of a voltage profile "at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault described by dynamic simulation provided by the Transmission Planner", puts the responsibility back on the Transmission Planner. Requirement R5 is intended to aid Transmission Planners in providing information on Generator models needed for Transmission Planning analyses, and yet as it exists the only option for provision of the information is a hindrance to Transmission Planners rather than an aid. PE requests that the SDT simplify the language to merely state that GOs have an obligation to provide information that the TPs request.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Westinghouse	No	a. This is for requirement 5 not requirement 4 **The SDT agrees.** b. We cannot evaluate the performance of units during frequency and voltage excursions at the transmission interface point, only at the generator and 6.9kV bus level where the auxiliary equipment interface exists. Therefore, the frequency and voltage excursion profiles would be different than those submitted by the RC, PC, TO or TP. **The SDT agrees that the profiles would be different which requires the Generator Owner to determine how they would translate to the specific facility based on its characteristics.** Also, 30 days is too short to perform a detailed analysis on plant performance during the frequency or voltage excursion. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** Further evaluation would be required for the transformers, turbine and auxiliary equipment to determine satisfactory operation in the long time periods encompassed in the "No Trip Zones". **The SDT agrees that this would be part of the evaluation.**
Response: Thank you for your comments. See specific responses above.		
Southern Company	No	1) This Question is for R5, not R4. **The SDT agrees.** 2) We disagree with this approach due to the uncertainty about how to estimate the performance. The detailed dynamic analysis required to make an estimate of a specific units performance is not reasonable to require. The voltage excursion profile needed for an evaluation is that voltage present on the generator bus and plant distribution system auxiliary buses rather than at the point of interconnect. The protective relays and control equipment susceptible to high/low voltage excursions are located on the low voltage side of the

Organization	Yes or No	Question 3 Comment
		generator step up transformer. Does agreeing with the approach mean the philosophical desire to provide the TP with information or mean agreement with the requirement to provide estimations of the voltage excursion ride-through ability? We agree with the philosophical mantra, but we are not sure if a conclusive determination of a unit ride-through capability is possible. Generation Owners need a curve from Transmission that is referenced to the lowside since that is where the relays/equipment are located. **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.** 3) Does "estimate of that unit's performance" only include the estimated time duration of 5.1 and probability of remaining connected in 5.2? Or, does it also include things like the estimated generator terminal voltage, MW, MVars, etc. for the duration of the frequency or voltage excursion? This needs to be clear. **The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The Requirement does not mention generator voltage, real power, reactive power, etc.** 4) The 30 days requirement is much too short. There are a large number of systems and components that would first have to be identified as susceptible to responding to these extreme conditions (especially the voltage conditions). Each of these would then require evaluation, including dynamic analysis for systems and components that respond dynamically over these relatively long time periods. This amounts to major study work on a single unit, much less over many units of many different system configurations and designs having equipment of many different manufacturers and vintages. Also, dynamic studies require accurate system and equipment models to produce valid results and the effort to establish accurate models is no simple task. **The SDT agrees that more time should be allowed and has changed the time to 60 days.**
Response: Thank you for your comments. See specific responses above.		
Oncor Electric Delivery Company LLC	No	It is unclear as to what constitutes an estimate of performance.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Exelon	No	This question refers to Requirement R5 not Requirement R4. **The SDT agrees.** The "ride through" criteria should not extend beyond currently used critical clearing time (2nd zone of

Organization	Yes or No	Question 3 Comment
		protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether nuclear units can survive anything beyond this. **The SDT does not believe it is necessary to extend the 0.0 pu voltage portion of PRC-024 Attachment 2 out to the critical clearing time (where this may be slower than 9-cycles). If normally cleared faults are cleared faster than 9-cycles at a specific location, the Generator Owner may use a voltage profile provided by the Transmission Planner for that site in lieu of PRC-024 Attachement 2.** Plants with auxiliary power systems fed directly from the nuclear switchyard would be even more questionable as the transient is not shielded by the generator bus. **The SDT agrees that it is challenging for many existing generation facilities (not just nuclear facilities). That is the reason for Requirement R5 (so the Transmission Planner, et al, have better information on how an existing facility will respond.**
Response: Thank you for your comments.		
Independent Electricity System Operator	No	We believe the SDT meant R5, not R4, unless R4 is a sub-requirement or a part of R3 (which seems to be the case by the way R4 is worded) and a format error resulted in R4 becoming R5. **The SDT agrees and has removed Requirement R4.** We do not support the provision of such an estimate. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions:a. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip;b. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2.We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and 2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? **The SDT agrees that determining the operation of protection system functions for a specific set of conditions is relatively straightforward, but the requirement for estimating the length of time a facility will remain connected includes evaluating upsets to the prime mover process that may result in a generator trip.**

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. See specific responses above.		
Wisconsin Electric	No	(We believe the relevant requirement for this question is R5).The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard.Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
We Energies	No	(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
We Energies	No	(We believe the relevant requirement for this question is R5). The estimate of generator performance desired by the RC/PC/TO/TP can be obtained via informal means, including meetings, discussion, and simply working together. Not all information that may be "useful" should be codified by a Requirement in a Standard. Also, R5 and associated Measure M4 refer to a "written request". This would seem to limit the request and response to a hardcopy. Using simply "request" instead of "written request" would allow the use of electronic means as well.
Response: Thank you for your comments. The SDT included Requirement R5 in order to ensure that the information is provided expeditiously. The SDT believes the word "written" (as opposed to "verbal") would include electronic communications as well as hard copies.		
Great River Energy	No	Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator, Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the

Organization	Yes or No	Question 3 Comment
		Generator Owner's best interest to be responsive. Thus, this requirement is not necessary.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Duke Energy	No	Should be R5. We question the value of this requirement, and how the TP use the probabilistic information in any TPL analysis. It's unclear how compliance with planning requirements would be demonstrated. The planner needs to know under what voltage/frequency conditions a unit will trip so that when those conditions are attained in the model the unit will be turned off. Generator owners/operators need to make their best efforts to determine the conditions and provide it to their TP's, updating the information as plant design changes occur or operating history indicates the conditions have changed. Having a time estimate as specified in R5.1 does not provide the voltage/frequency threshold that the planner must know so that the unit can be tripped when those conditions occur in the model, no matter what time those conditions occur.
Response: Thank you for your comments. The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard. The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.		
Western Electricity Coordinating Council	No	The question above appears to be referring to R5, not R4. R5 has the requirements for providing estimates of the performance of the units. I have no comments on R5, However, I have the following comment on R4.We agree with the intent of the requirement, but believe that more specificity in what is required in the written response is necessary. As written it could be argued that a simple response from the Generator Owner indicating they received the inquiry was sufficient. Suggest adding detail similar to that included in MOD-026, Requirement 3 that identifies what the response must contain.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP assumes this question actually applies to Requirement R5. It is not clear what extra reliability information will be provided to Transmission Planners as long as Generator Owners confirm that their voltage and frequency settings comply with the performance curves in the attachments. It may be valid to require an estimate of performance if the GO identifies a limitation as allowed under R3. Otherwise, the TP should assume generator relays will operate if the magnitude and duration thresholds defined in the attachments are exceeded.
Response: Thank you for your comments. The SDT has removed Requirement R4.		

Organization	Yes or No	Question 3 Comment
Luminant Energy	No	Note: This appears to be dealing with R5 and not R4.R5 Because of the requirement under R5.3 (identification for basis for estimates of probability of staying on-line, etc), the study would take considerable time to compile. I would recommend that the generator owner be provided 90 calendar days rather that the suggested 30 to submit the results. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** R5.1 It appears that a frequency and voltage excursion must occur at the same time with the estimated time duration that the unit will remain connected. Was it intended that the “and” be an “or”? **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.** Would LVRT dovetail into relay loadability for stressed conditions for low voltage conditions between 45 and 90%? (Generator relay loadability is evaluated at 85% (PRC-023-2).) . **The SDT does not believe that this would replace an evaluation of relay loadability.** R5.3 Luminant recommends removing this requirement. . **The SDT believes this information will help the Transmission Planner determine a level of confidence in the estimate.**
Response: Thank you for your comments. See specific responses above.		
Ameren	No	Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine this probability with any reasonable accuracy. For example, where auxiliary motors would stall and trip off, or contactors drop out would be variable
Response: Thank you for your comments. The SDT agrees that this is an estimate and not deterministic. The performance of contactors is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.		
PPL Electric Utilities	No	1. Excursion-estimate requirements for existing units are presented in R5, not R4. Our comments below pertain to R5.2. The question above cites “frequency and voltage excursions [emphasis added],” the question 4 below deals with “frequency or voltage excursions,” para. R5.1 states “Frequency Excursion...and a Voltage Excursion” and para. R6 references “Frequency Excursion or Voltage Excursion.” The combinations of simultaneous frequency and voltage variations that units must ride-though should be clarified. **The SDT has revised the wording for Requirement R5 so that, if requested, the Generator Owner must provide an estimate of the time a generating unit or facility will remain connected based on an excursion defined by the Transmission Planner.**

Organization	Yes or No	Question 3 Comment
		3. Preparing the estimates in question appears to constitute a duplication of the excitation and governor model verifications required by MOD-026 and MOD-027. Para. R5 states that the PRC-024 estimates are to be used in modeling studies; but there should be one, definitive source of modeling data, not two different sources. Para. R5 of PRC-024 should be replaced by a reference to using the tools developed for MOD-026 and MOD-027. **Requirement R5 in PRC-024 requires the Generator Owner to develop an estimate of the time a facility will ride through an excursion. This is significantly different than the verification of performance called for in MOD-026 or MOD-027.** 4. In the event that R5 remains as-is, a standard-specific definition of the word “plant” is needed, restricting applicability to NERC-registered generators. A plant consisting of two 750 MW fossil units and a standby 10 MW diesel generator, for example, should not have to model the diesel unit’s behavior. **The Applicability is to Generator Owners. By default, all generating units and facilities that meet the NERC Registry Criteria fall within the applicability of this standard.** 5. It is necessary in any event to limit the requirement for estimates to that which can reasonably be modeled. Unit auxiliary system buses may drop-out and cause a unit to trip, even if the generator and protective relays can handle any given transient, and dynamic behavior at the 4160V and 460V levels may be impossible to predict for the radical excursions specified in PRC-024. **The SDT agrees that this is an estimate and not deterministic. The performance of contactors, for example, is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.**
Response: Thank you for your comments. See specific responses above.		
Indiana Municipal Power Agency	No	This is actually requirement R5. IMPA does not see any value in assigning a standard requirement to a Generator Owner that is just an estimation of performance when it might be a far off estimation of performance compared against actual performance of an existing unit or generating plant. This standard should concentrate on the setting of relays and not have Generator Owners estimate how their unit or generating plant will perform during a Frequency/Voltage Excursion. This standard should also not force Generator Owners to perform studies or model their unit or generating plant since they are not guaranteed or reliable either.
Response: Thank you for your comments. The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling. If the Reliability Coordinator, Planning Coordinator, Transmission Operator, or Transmission Planner do not believe there is a reliability value in requesting the information described in Requirement R5, then they are not required to request it.		

Organization	Yes or No	Question 3 Comment
GenOn Energy	No	The comment is for R5 for the June 15, 2011 draft. The wording is too open-ended and subjective in scope. Similar to R1 & R2, the requirement should be clearly defined and limited to devices that directly respond to generator voltage or frequency. **The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling, including the performance of the generating unit or generating facility beyond just the performance of the protection system.** R3 already requires the information of other control or protective devices. **The SDT disagrees. Requirement R3 requires information on equipment limitations (other than limitations of control or protection systems).** Typically, the Generator Owner does not monitor the interconnection voltage for protection purpose; rather generator terminal voltage is used for generator protection. The modeling is performed by others, but the burden of analysis is being placed upon the Generator Owner to determine performance probability for information not in their possession. **The SDT believes that the Generator Owner is the entity that can best develop an estimate of performance of a generating unit or generating facility as described in Requirement R5.** 30 days is a short period of time for this analysis when hit cold with a request like this, especially during outage season. **The SDT agrees that more time should be allowed and has changed the time to 60 days.**
Response: Thank you for your comments. See specific responses above.		
Imperial Irrigation District (IID)	Yes	According to the standard this language is R5
Response: Thank you for your comments. The SDT agrees.		
MRO's NERC Standards Review Forum	Yes	This question seems to be referring to R5 rather than R4.
Response: Thank you for your comments. The SDT agrees.		
Dynamics Review Subcommittee	Yes	We assume this pertains to R5 not R4. 30 days is probably not enough time for a GO to determine a suitable estimate. We recommend 90 days.
Response: Thank you for your comments. The SDT agrees that more time should be allowed and has changed the time to 60 days.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	Although we agree with the requirement, we noticed that the VRF and Time Horizon is missing for R4. We suggest a LOWER VRF and Long-term Planning Time Horizon.
Response: Thank you for your comments. The SDT has removed Requirement R4.		
ISO New England Inc.	Yes	The RC/PC/TOP/TP functional entities provide for a wide-area view of the transmission system and its operating limitations. These entities need accurate generator characteristics in order to correctly plan the system and to operate it within known limits.
Response: Thank you for your comments. The SDT agrees.		
American Electric Power	Yes	A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
Response: Thank you for your comments. The question was written to apply to Requirement R5. If the Generator Owner has activated protective functions that are set inside the "no trip zone" in PRC-024 Attachment 1 or Attachment 2 and does not know of a technical limitation to changing the settings, then they can be changed and the Generator Owner will be in compliance.		
American Electric Power	Yes	A Generator Owner should only be required to report known limitations that might cause their unit to trip. As written, one could be in violation of the standard for some unknown limitation which might exist and that might only be known after an event has occurred. This question seems unrelated to R4 which states the time provided to respond to a written request for information. Rather, it seems to be related instead to R3 or R5.
Response: Thank you for your comments. The question was written to apply to Requirement R5. If the Generator Owner has activated protective functions that are set inside the "no trip zone" in PRC-024 Attachment 1 or Attachment 2 and does not know of a technical limitation to changing the settings, then they can be changed and the Generator Owner will be in compliance.		
Public Service Enterprise Group	Yes	
NERC Staff Technical Review Team	Yes	
PacifiCorp	Yes	(R4 referenced in the question actually should refer to R5 in the standard)

Organization	Yes or No	Question 3 Comment
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Austin Energy	Yes	
Xcel Energy	Yes	
South Carolina Electric and Gas	Yes	
US Army Corps of Engineers	Yes	
RFC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
GE Energy	Yes	
American Transmission Company	Yes	

4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer.

Please provide along with your comment, what you believe the timeframe is needed to implement this requirement.

Summary Consideration: The question mistakenly referred to Requirement R5 due to changes to the standard made by NERC Staff after the SDT had submitted the standard. This error was observed by the stakeholders and the SDT believes the responses accurately reflect the feelings of industry to the intended question. The majority of stakeholders agreed with the proposed requirement.

Based on the response to the question, no major changes were made to Requirement R6.

Organization	Yes or No	Question 4 Comment
Occidental Chemical	Negative	4. Requirement R5 requires a Generator Owner's new unit or generating plant/facility to be able to stay on line when exposed to point-of-interconnection frequency or voltage excursions depicted in the curves of Attachment 1 and Attachment 2. Do you believe this requirement is technically achievable for new units or generating plant/facilities? Please provide comments supporting your answer. Please provide along with your comment, what you believe the timeframe is needed to implement this requirement. Yes: Comments: Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Response: Thank you for your comments.		
Northeast Power Coordinating Council	No	The refererence to "R5" in this question should be R6.
Response: Thank you for your comments. The SDT agrees.		
SERC Generation Sub-committee (GS)	No	This appears to refer to R6.The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design

Organization	Yes or No	Question 4 Comment
		guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, It is not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants.It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
MRO's NERC Standards Review Forum	No	If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		
Electric Market Policy	No	This appears to be a design question that presumably the standard drafting team researched and quantified to provide a basis in framing the curves of Attachment 1 and Attachment 2. If this is true, more documentation

Organization	Yes or No	Question 4 Comment
		should be provided to the ballot body.
Response: Thank you for your comments. The curves of PRC-024 Attachment 1 match the curves for "Expected Generator Tripping" in PRC-006 Attachment 1 that sets expectations for UFLS system performance. There is a margin between the UFLS performance expectation and the generator tripping curves. The curves of PRC-024 Attachment 2 were developed based on the existing wind generator low voltage ride through curve in FERC Order 661-A, studies done in WECC and various European voltage ride through requirements (see the Reference cited in the Standard). All of this information is available to the ballot body.		
FirstEnergy	No	Requirement R5 - It may not be feasible for the GO to provide this information in 30 days. We suggest allowing 90 days. **The SDT agrees that more time should be allowed and has changed the time to 60 days.** Regarding 5.2 and the estimation of the probability, we are not clear as to what is required. The wording is confusing and cannot offer suggestions because we are not sure what the intent is. **The SDT agrees with stakeholders who have commented that the estimated probability of ride-through does not provide any reliability value and has removed the wording from the standard.** R5.1 - Some nuclear plants will not be able to run at 95% voltage indefinitely as required as that voltage is lower than each plant's Licensing Basis for degraded grid voltage. We ask that this standard include an exception for nuclear generators that allow them to report what % of grid voltage will force them into a Limiting Condition of Operation if that % voltage is higher than 95%. **The condition described would be a technical limitation and would allow the Generator Owner of that facility an exemption from that portion of the PRC-024 Attachment 2 "no trip zone" that the limitation describes.**
Response: Thank you for your comments. See specific responses above.		
Santee Cooper	No	This appears to refer to R6.The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidence provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)"as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants

Organization	Yes or No	Question 4 Comment
		designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilzed at power generation plants.It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
Florida Municipal Power Agency	No	First, FMPA believes the SDT is referring to R6 not R5. Technically, the requirement is inconsistent with the question. The requirement is to design, build and maintain to prevent tripping, it does not say “thou shall not trip”. If a generator is designed, built and maintained to specifications that should not trip, but, a generator trips anyway in a real-life event, is that a violation?
Response: Thank you for your comments. The SDT disagrees that with FMPA’s interpretation. The actual wording is “Each Generator Owner shall design, build, and maintain its new unit or new generating plant or generating Facility so that it will not trip… “. As written, a trip during a frequency or voltage excursion that remains within the boundaries of the “no trip zones” in PRC-024 Attachments 1 and 2 would be a violation.		
TVA - GO	No	The proposed bands would need to be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency band was considered for some new plant designs and no concerns were identified. However, it is not clear if all or even most of the designers for other nuclear/fossil designs have considered this. The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) have been and are normally designed for proper operation as follows: The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”as follows: a. Normal Conditions: Â±5% Continuous Duration b. Emergency Conditions: Â±10% not specified Duration These Criteria are

Organization	Yes or No	Question 4 Comment
		currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions. For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting less than one second, can be more severe and the equipment can still ride through it for about 0.5 seconds. A design solution to address severely degraded voltage lasting more than one second, is to utilize expensive voltage regulation devices, normally not utilized in the past at most power generation plants. It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate reasonable steam plant voltage excursion ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
Arizona Public Service Company	No	AZPS believes this question applies to R6. There should be an implementation period for the requirement for new units to allow the plants which have been ordered already to not to have to be redesigned.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		
Luminant Power	No	Luminant believes it may be technically possible to design a new generating unit or facility to ride through a low voltage event even though the cost to do so may be prohibitive and impractical. However, Luminant does not believe it is reasonable or achievable to expect the Generator Owner to be able to maintain those capabilities in perpetuity due to equipment deterioration and aging over time even though proper maintenance practices were implemented.
Response: Thank you for your comments.		
Progress Energy	No	This appears to actually refer to R6. **The SDT agrees.** PE submits the comments below with the assumption that this question is directed toward R6: The ride through voltage profile in attachment 2 is not achievable for either new or existing facilities. The issue is not the relay protection but in the capability of the auxiliary equipment (such as motor contactors, coal feeders,

Organization	Yes or No	Question 4 Comment
		instrument sensors). I do not know of any motor control contactor that will hold in when voltage goes to zero. The energy that is stored in the coil holding the contactor in place is rapid returned into the system during a time of fault. While the short circuit contribution of motors and contactors may last up to .2 seconds the majority of the stored energy is returned in the first 1/5 of the decay curve. The requirements that are specified in this standard are outside the IEEE and ANSI standards associated with manufacturing equipment used in power plants, while manufacturing of equipment to specialized standards MAY be possible the cost would be extremely high and in some cases may not be possible. **Existing plants are not required to comply with Requirement R6. For the example cited regarding contactor performance, a new plant could be designed with the contactors fed from a DC source or a UPS system. European utilities must comply with ride-through standards now. The SDT agrees that this would increase the cost of a facility.**
Response: Thank you for your comments. See specific responses above.		
Westinghouse	No	a. This is for requirement 6 not requirement 5 **The SDT agrees.** b. It is uncertain that the requirements, when translated to the 6.9kV AC distribution system and below, can be achieved with the equipment installed in new generating facilities. Most motor specifications do not require demonstrated operability below 75% motor rated terminal voltage or >5% deviation in rated frequency. Additional vendor testing would be required in order to effectively demonstrate equipment design capabilities. Additionally, plant performance has not been evaluated for the entire range of frequencies in the "No Trip Zone". More analysis would have to be performed in order to verify acceptable plant operation in these frequency bands.
Response: Thank you for your comments. A 5% deviation in frequency is 3 Hz. PRC-024 Attachment 1 allows the generator to trip if the frequency reaches 57.0 Hz or 63.0 Hz. The SDT believes the comment regarding 75% voltage relates to continuous voltage level, not a fast transient.		
Southern Company	No	1) This question is for R6, not R5. **The SDT agrees.** 2) We highly doubt that the requirement is technically feasible based on our experience with vendors and the various technical requirements and modifications that would have to be made to make sure that low or high voltage ride thru is possible. Complicating factors include the many different equipment suppliers, limited control of manufacturing standards by the purchasers, and continuing changes in technology must be considered to be able to determine whether or not all plant sub-systems can ride through. The economic impact and technical feasibility of this requirement has not yet been considered by suppliers**. European utilities must comply with ride-through standards now.** 3) Even if this can be achieved, it will require significant changes in the power plant industry. This will

Organization	Yes or No	Question 4 Comment
		include major changes to plant system and equipment design standards (both U.S. and International). This alone will take years to accomplish. Then, manufacturers will have to design, build, and test plant systems and equipment to meet the new requirements. It is impractical to expect a new plant that can meet both the frequency and voltage requirements to be built in less than 10 years after R6 is imposed. **The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	No	There are going to be certain exceptions to new units or facilities being capable of staying on line under the listed circumstances just as there are current exemptions for existing facilities. Exceptions could be related to VFD (variable frequency drive) operation or motor operation at the plants, which would be true of both existing and new generating plants. There is also a possibility of overcurrent trips during these voltage conditions, tripping would not necessarily be limited to voltage or frequency relays. It would be difficult for Generator Owners to answer this question fully without a thorough study of how the frequency and voltage excursions will impact generation loads. Generation protective relays do not typically base their protection on transmission system voltages at the point of interconnection.
Response: Thank you for your comments.		
Manitoba Hydro	No	While the requirement is technically achievable, justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the ‘no trip zone’ limits are set where they are.
Response: Thank you for your comments.		
Great River Energy	No	If design standards have not been previously developed or implemented for all plant equipment and therefore the plant itself to not trip during the defined excursions it is uncertain when and if equipment design standards and the equipment itself can become available to achieve the requirements.
Response: The SDT has extended the implementation of Requirement R5 to six years to allow for the development of designs that meet the Requirement.		
Duke Energy	No	This appears to refer to R6. **The SDT agrees.** The proposed bands should be considered by new plant designers and incorporated into their design basis if feasible. Specific criteria have not been provided in new plant design guidance provided by EPRI Utility Requirements Document (URD) nor in other industry standards used by new plant designers. The frequency

Organization	Yes or No	Question 4 Comment
		band was considered for some new plant design basis and no concerns were identified. It's not clear if all or even most of the designers for other nuclear/fossil designs have considered this.The proposed voltage band has caused many concerns and probably is not achievable for existing or new steam plants because electrically powered equipment (motors, MCC components, contactors, etc.) has been and is normally designed for proper operation as follows:The normal voltage boundaries have been specified to be for the steady-state operating conditions based on the ANSI C84.1-2006 "American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)"as follows:a. Normal Conditions: Â±5% Continuous Durationb. Emergency Conditions: Â±10% not specified DurationThese Criteria are currently widely used in practice and can be complied with by all types of new generating plants designed with an in-plant voltage regulation capability. In connection with these criteria, all new equipment, both on the transmission system and in new generation plants must be chosen in order to be able to operate and withstand these voltage excursions.For transients, the above should be applied for conditions lasting more than one second. Transient conditions lasting more than one second, can be more severe and the equipment can still ride through it. A design solution to address severely degraded voltage lasting more than one second is to utilize expensive voltage regulation devices, normally not utilized at power generation plants. This standard shouldn't dictate a solution to the situation where a generator goes offline due to low voltage on the transmission system, because in many cases the generator going offline may not be a problem for the overall transmission system. In situations where it is a problem, a collaborative effort between the Transmission Planner and the Generator Owner would be the best approach (see AREVA white paper that has been provided to the SDT).It's not clear why a plant should be required to withstand any transient beyond that expected by a switchyard fault with one failed breaker (the basis for critical clearing times for second zone or breaker failure protection). An R&D effort should be considered to investigate steam plant ride through capabilities if a criteria is needed.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement. ANSI C84.1-2006 (now called NEMA C84.1) only defines continuous voltage levels. The designer of a new generating facility would have to determine how best to ensure the equipment be installed to ensure compliance with Requirement R6. The Standard allows the Generator Owner to design for faster clearing and faster voltage recovery if provided by the Transmission Planner. Critical clearing time may be significantly longer than nine cycles and the SDT did not want to subject generators to those conditions.		
US Army Corps of Engineers	No	R5 applies to existing units. This requirement seems vague and subjective - recommend clarification. Please clarify the term "less stringent" - do you mean 'in the no-trip zone' or 'outside the no-trip zone. How will the information be used and what are the implicatios if the response is not satisfactory? R6 applies to new units - I have no comments on R6.
Response: Thank you for your comments. The SDT intended "less stringent" to mean a smaller "no trip zone" due to faster fault clearing and/or		

Organization	Yes or No	Question 4 Comment
faster voltage recovery time. The information would be used to better model generator response to system disturbances.		
Luminant Energy	No	Generating units placed in service prior to this standard normally have 30+ years lifespan. During the life span, components targeted for LVRT will experience loss of life (time in use, number of operations, environment, etc) which could result in a failure of an LVRT event at the point of interconnection. Because a study may not be able to locate every component, an increase in reliability or the ability of the plant to ride through a low voltage condition could never be guaranteed above its current level. The same issue exist for new units. If the plant was designed to maintain LVRT conditions, there is no guarantee that the plant's ability to ride through low voltage conditions can be maintained during its life span.
Response: Thank you for your comments.		
Ameren	No	Unless written to exclude all auxiliary system equipment which may result in a unit shut down, it will be impossible to determine with any reasonable accuracy where auxiliary motors would stall and trip off, or contactors drop out.
Response: Thank you for your comments. The SDT agrees that this is an estimate and not deterministic. The performance of contactors, for example, is highly dependent on the phase angle of the voltage wave when the excursion occurs – which cannot be predicted. The Generator Owner may want to assume a worst case scenario.		
American Electric Power	No	This question references R5, but we believe the team intended to reference R6. **The SDT agrees.** The requirement for new units and plants to not trip within the envelope of Attachment 1 is reasonable; the design of turbines involves some off-nominal frequency versus accumulated time criteria and Attachment 1 is being proposed in view of existing design criteria of major manufacturers. While the Standards team has proposed this in view of OEM design criteria, it would be beneficial to obtain input from the OEMs to learn what issues if any they have with this proposal and what changes and/or incremental costs could be incurred to meet the Standard for new or existing generators. **The SDT has reviewed OEM information. Modern steam and combustion turbines can all meet PRC-024 Attachment 1. Two OEM's have commented on this standard and have not objected to Attachment 1.** The design and ability of auxiliary systems to meet the requirements outlined in Attachment 1 will require review.To not trip within the envelope of the Attachment 2 Voltage Ride-through Time Duration Curves is another matter. No requirement such as this has ever been imposed on generating units in the past and we question the need for it now. The appearance of such graphs seems to have been in response to the performance of wind farms that tripped off-line by protective relays when disturbances occurred on the transmission system. The Attachment 2 VRT curve may thus be an appropriate requirement for wind turbine generators. The applicability to conventional generation, however, is questionable. Further, the curve and the

Organization	Yes or No	Question 4 Comment
		supplemental tables (curve data points) seem to be at odds with the language of R2, e.g. R2.1.1 which states for three-phase transmission system zone 1 faults with Normal Clearing, interpreted to mean as little as 3 cycles up to and not to exceed 9 cycles depending on the transmission relay practice and transmission voltage application.Specific comments on and objections to R6-Attachment 2 are as follows: (1) It is not at all clear that a conventional generating unit could maintain synchronism during POI voltage events within the envelope of Attachment 2. The standard needs to explicitly state that Attachment 2 is not a requirement to maintain synchronism (which is already covered by TPL standards). This point must be made clear within either the text of the requirement or else in a footnote, not just the comment form. (2) Should the SDT retain this requirement, it would be advisable to limit the scope of Attachment 2 in R6 to generator over- and under-voltage relay settings and any unit auxiliary equipment over- and under-voltage protection whose operation could lead to the loss of the unit. However, it is also not at all clear whether auxiliary systems could be designed to withstand voltage disturbances within the envelope of Attachment **Requirement R6, part 6.7 allows generating units to trip for an actual or impending loss of synchronism.** 2. Further complicating auxiliary systems ride-through, while such a graph may be appropriate for wind farms, it is not appropriate for conventional synchronous generators that have a substantial capability to control the voltage they are subjected to during a system disturbance (unlike most wind farms) and whose critical auxiliary systems are usually (and should be) served from the generator bus (low side of GSU) and are thus insulated to some extent from what may happen on the transmission system. A more appropriate requirement for conventional generation would be to require an automatic over-excitation limiting (OEL) function that is coordinated with over-excitation protection. However, we believe OELs are now standard equipment among excitation equipment suppliers and should not need to be required in a standard. (3) It would be impractical, if not impossible, to test or otherwise verify generator ride-through for POI voltage disturbances within the envelope of Attachment 2. In view of the above considerations, and in the interest of treating all generation types equitably, we believe a more appropriate approach to generator voltage ride-through would be deference to TPL standards for the types of transmission system disturbances where stability needs to be maintained. This has always been an acceptable criterion for conventional generation ride-through in the past. It is not stated in these terms in this proposed standard and independent review of a random sample of units could demonstrate the units may not meet this R6-Attachment 2 performance requirement though they would meet R2.1.1 and TPL standard requirements.It would be beneficial to state somewhere that any fault or other disturbance on the transmission system for which a conventional generator is expected to survive, a wind farm must also survive without tripping. (A statement such as that may be out of place in this standard and perhaps ought rather to have been included in the new TPL-001-1.) The proposed VRT criteria requires more study and analyses before introducing it so broadly in this standard for other than for wind turbine generators for which it has already been applied. Therefore, for the purposes of the R6 performance requirement, we believe that reference to Attachment 2 should be removed. **The SDT agrees that it is not necessary to place a requirement for OEL's in a standard and has not added it to this standard. The SDT also agrees with the impracticality of verifying ride-through capability through testing and has**

Organization	Yes or No	Question 4 Comment
		not included any requirements to this effect. One of guidelines the SDT is working under is FERC's desire for ride through performance to meet the TPL standards as they expressed in Order 693. The SDT has tried to write this standard in a technology-neutral manner. The requirements apply equally to wind (and other variable energy resources) as to conventional synchronous generators.
Response: Thank you for your comments. See specific responses above.		
Indiana Municipal Power Agency	No	This is actually requirement R6. **The SDT agrees.** IMPA does not believe this technology is currently achievable for new units or generating plant/facilities on all generation producing fronts. The technology should be in place and proven on all generation fronts before such writing of standard requirements.
Response: Thank you for your comments.		
GenOn Energy	No	Applied to R6 of the June 15, 2011 draft. It does not appear that the SDT has carefully considered the possible impact of Attachment 2 on plant electrical auxiliary motors and contactors. The SDT should ask an power plant engineering company the impact on the electrical auxiliaries of an 800MW coal unit with a scrubber.
Response: Thank you for your comments. The SDT realizes that there would be a significant impact on the design of plant auxiliary systems.		
Idaho Power - Power Production		This requirement should not exist. Generator Owners are required to comply will all approved NERC and RRO standards. It is the responsibility of the Generator Owner to see that the plant is built according to specifications which should include all approved NERC Reliability standards governing power plants.
Response: Thank you for your comments. The SDT is charged with complying with FERC Order 693 and the recommendations in the 2003 Black Out Report to improve system modeling.		
Bonneville Power Administration		R5 - WECC Reliability Subcommittee discussions indicated that protection generation relay performance at the Point of Interconnection was different than if the measurement point is at the low side or high side of the step-up transformer. The NERC Standard should specify the measurement point at the high side of either the generator step up transformer, or at the high side of the collector transformer where multiple small generators are aggregated at a collector substation.Attachment 2 - BPA suggests modifying the diagram to reflect changes to Requirement R2.1.1 above, e.g. to show that allowable voltage relay trip time is greater than the normal fault clearing time if the normal clearing time is less than 9 cycles.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The voltage curves presented in PRC-024 Attachment 2 are already described as being at the high side of the GSU or collector transformer. The SDT believes that section 2.1.2 conveys the Generator Owner is allowed to use actual fault clearing times of less than nine cycles to set voltage-affected relays if the Transmission Planner provides the site-specific expected voltage characteristics.		
Austin Energy		The curves in Attachment 1 are more restrictive than the current ERCOT Operating Guide requirements. The equipment impact of this new requirement requires additional internal review, before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
Response: Thank you for your comments.		
Pepco Holdings Incand Affiliates	Yes	Believe this question is referring to Requirement R6 not R5 as stated in the question. **The SDT agrees.** Yes, it is possible to design a new facility to operate within the requirements identified in this standard. However, it may require specification of equipment with higher than normal overvoltage capabilities. Also, significant analyses would have to be conducted on the behavior of plant control systems (exciter controls, boiler controls, etc.), as well as equipment connected to auxiliary busses (including low voltage motor contactors) to ensure that all systems are designed with appropriate ride-through capabilities. However, it is unclear how this standard would apply to the ride through capability of units connected to the BES, but whose source of auxiliary station service power is from a non-BES interconnection. Would the units also have to ride through expected voltage excursions at the point of interconnection with the station service transformer even if the station service transformer was not fed directly from the BES?
Response: Thank you for your comments. The SDT believes that a generating facility that meets the NERC Registry Criteria for size and connection voltage would have to meet this standard regardless of its source of auxiliary station service power.		
Imperial Irrigation District (IID)	Yes	According to the standard this language is R6
Response: Thank you for your comments. The SDT agrees.		
BC Hydro and Power Authority	Yes	Frequency and voltage excursions specified in this standard are reasonable and actually less stringent then certain regional or area requirements. Generating facilities designed in line with industry practices and applicable standards should be able to ride through such disturbances. Lastly, it is in GOs best interest to have a robust design for new generating facilities.
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
SPP Reliability Standards Develpment Team	Yes	Question should read R6 not R5. **The SDT agrees.** We feel that as long as everyone knows about these requirements ahead of time that there shouldn't be an issue with achieving these requirements.
Response: Thank you for your comments.		
Dynamics Review Subcommittee	Yes	Requirement R6 not R5.
Response: Thank you for your comments. The SDT agrees.		
LG&E and KU Energy	Yes	: This appears to be R6, not R5 and should be achievable for new units.
Response: Thank you for your comments.		
PPL Supply	Yes	1. Excursion-estimate requirements for new units are presented in R6, not R5. Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. **The intent is to ride through a voltage excursion or a frequency excursion, not both simultaneously.** 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult. **This standard does not require demonstration by dynamic simulation.**
Response: Thank you for your comments. See specific responses above.		
American Wind Energy Association	Yes	New reliability standards should be accompanied by grandfathering provisions for existing generators and an implementation grace period of sufficient length to ensure that manufacturers have enough time to engineer their generators to comply with the standard and that generators for which purchase orders are already in the pipeline will not need to be re-designed. The grandfathering provisions and implementation grace period schedule that were included in FERC Order 661A should be sufficient to achieve those goals if they are incorporated into this standard.
Response: Thank you for your comments. These grandfathering provisions are already written into the standard. Requirement R6 specifically states that it applies to units that are designed and built after the standard goes into effect.		

Organization	Yes or No	Question 4 Comment
New York Power Authority	Yes	It is achieveable but signficant analyses must be performed. Undervoltage relay settings must be coordinated with the plant components most sensitive to system wide voltage excursions, particularly voltage drops. In some facilities, a POI voltage dip to 0.95pu would translate to a much larger drop within the local facility such that facility auxiliaries would start tripping due to the lower volatges on the facilities internal buses. The result is that even thogh the HV bus undervolatge relay is set to allow 0.95pu on the system the facility internal distribution may not be able to cope with voltage at that low a level. Nuclear power plants are particularly susceptible to low voltage conditions as unplanned tripping of a nuclear unit is to be avoided as much as possible. Nuclear units are also susceptible to overfrequency excursions as overfrequency causes motors within the plant to run at higher speeds. Nuclear reactor coolant pumps have overspeed limits due to core internals vibration limits that must be analyzed and coordiated with system overfrequency relay settings. These analyses typically take six to twelve months to complete and validate so a 12 to 18 month timeframe should be sufficient to implement the requirement.
Response: Thank you for your comments. Existing generating facilities are allowed an exemption from portions of PRC-024 Attachment 1 and Attachment 2 for documented technical limitations such as you describe in your examples. No additional analysis would be necessary. For new units that are designed and built after the standard is implemented, the SDT believes the analysis cited would be part of the plant design process.		
Puget Sound Energy	Yes	This would require detailed information from the manufacturer of a combustion turbine. The requirement appears to be entirely reasonable for hydro installations. We expect it would take two years to complete this work.
Response: Thank you for your comments. The SDT has reviewed information from various steam and combustion turbine manufacturers. Two OEM's have commented on this standard.		
Independent Electricity System Operator	Yes	First of all, we believe the SDT meant R6, not R5. **The SDT agrees.** Also see our editorial comments under Q3, above. We believe this requirement is achievable for most cases. However, provision should be given to the Generator Owners which for specific technical reasons are unable to design a generating units to comply with the requirements. As worded, R6 does not contain this provision. **The SDT does not agree that this would be workable exception.**
Response: Thank you for your comments. See specific responses above.		
Xcel Energy	Yes	It is Requirement R6 that requires new units to ride through excursions. We believe it is technically feasible to design generating units to reach a high probability of riding through these excursions. However we do not consider the additional expense necessary to meet this objective to be of value to our customers given the

Organization	Yes or No	Question 4 Comment
		infrequency of occurrence of excursions of the magnitude described in this standard. Excursions of this type have occurred on our system and some generating units have tripped due to the excursion, but it has never led to a cascading outage. In addition, we believe new plants should not be considered in violation for a trip during an excursion if the GO can identify the reason for the trip and correct the deficiency. If the standard is made mandatory, we believe that an additional five years should be allowed for new units so that the A/E firms can develop proper design criteria for plant auxiliaries and equipment OEM's to develop designs that can handle the requirements
Response: Thank you for your comments. The SDT does not agree that the Generator Owner would not be in violation even if a mitigation plan were developed to address the cause of a trip during a frequency or voltage excursion.		
ISO New England Inc.	Yes	ISO-NE has frequency data from all generators operating within the New England footprint demonstrating, with the exception of certain nuclear plants and some smaller and very old generating units, that all generators can operate to meet the under-frequency curve depicted by PRC-024 - Attachement 1, and, in fact, can and do meet our more stringent underfrequency requirements. Within the NPCC Region existing requirements for generators have been in place for many years that are more stringent than the underfrequency curve shown here. The NPCC more stringent requirements have been shown by studies to be necessary to support a viable automatic unferfrequency load shedding program. It is our position that generators within NPCC will be required to continue meeting these more stringent requirements independent of the approval of PRC-024-2. New generating units should meet all the PRC-024-2 requirements at the time of their interconnection or in-service date. No special implementation plan should be afforded these units beyond the regulatory approval date of the standard.
Response: Thank you for your comments. The SDT believes that designing new facilities to meet the PRC-024 Attachment 2 voltage ride-through requirements will be challenging and has extended implementation of this requirement to six years from the date of approval.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP assumes this question actually applies to Requirement R6. **The SDT agrees.** The frequency and voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view.
Response: Thank you for your comments.		
RFC	Yes	For R5, Part 5.1 and 5.2 - suggest adding the word "PRC-024" in front of "Attachment 2" in the last line of the respected Parts.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The wording in this requirement has been revised.		
Tacoma Power	Yes	
GE Energy	Yes	**1.** The requirement is achievable in concept, however, there is a serious omission in the definition of the requirement. It is not clear how the magnitude of the three phase voltage is defined, for example: average of the individual phase magnitudes, magnitude of the least phase, positive sequence. Also, it should be clearly defined whether the requirement applies to the rms, 60 Hz component, or peak magnitude of the voltage. **Thank you for your comments. The SDT agrees and has changed the wording accordingly. Clarification #5 has been added to PRC-024 Attachment 2 that states "Additionally, voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve."**
PPL Electric Utilities	Yes	1. Excursion-estimate requirements for new units are presented in R6, not R5. **Requirement R5 contains the requirement for estimating performance during an excursion.** Our comments below pertain to R6. 2. Avoiding tripping for 10 minutes of operation at +/- 10% voltage may not be practical, especially if combined with the frequency excursions of Att. 1. **Events that cause severe frequency excursions frequently are accompanied by voltage excursions (though usually not of the severity described by PRC-024 Attachment 2).** 3. See also the final two comments for question 3 above. Preventing (and demonstrating via dynamic analysis the ability to prevent) aux buses from dropping-out at the specified interconnect voltage transients may be especially difficult. **This standard does not require demonstration by dynamic simulation.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	
NERC Staff Technical Review Team	Yes	
Westar Energy	Yes	
Tri-State Generation and Transmission, Inc.	Yes	

Organization	Yes or No	Question 4 Comment
Oncor Electric Delivery Company LLC	Yes	
Tacoma Power	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
American Transmission Company	Yes	

5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments.

Summary Consideration: The slight majority of stakeholders indicated that they agree with the 600 second value. A large portion of stakeholders who responded "no" indicated that they felt the 600 seconds was acceptable but had other concerns with the standard. As a result of the responses to this question the SDT did not make any changes to Attachment 2.

Organization	Yes or No	Question 5 Comment
PacifiCorp	Negative	(3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered: 2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided: 2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time. 2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to in PRC-024 Attachment 2. 2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the "no trip zone" in PRC-024 Attachment 2 is acceptable. 2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable.
Response: Thank you for your comments. The SDT has revised the wording in the subsections of Requirement R2 to make the intent clearer. Section 2.1.1 has been removed. Section 2.1.3 now says "Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2." Section 2.1.4 now says" If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."		

Organization	Yes or No	Question 5 Comment
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	(3) This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The SDT has not changed the standard in response to this comment.		
PacifiCorp	Negative	(7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **Interaction of other power system parameters has not been addressed. However, it should be noted that reactive requirements for generating facilities is identified in Standard VAR-001 and VAR-002, and the LGIA.** (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a “one-size fits all” standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT is well aware that many European generation interconnection standards and requirements (Grid Codes) that have been developed, which include different voltage ride-through requirements for synchronous and non-synchronous generators (see Reference 1). While this same approach could have been included in this standard, after much discussion the STD has decided to develop one frequency and voltage ride-through standard that is inclusive of all technologies. Such an approach is considered technology neutral.**
Response: Thank you for your comments. See specific responses above. .		
Occidental Chemical	Negative	5. The voltage ride-through Tables HVRT and LVRT Duration in Attachment 2, specify time duration of up to 600 seconds that a unit or a generating plant/facility should ride through a voltage excursion. Do you agree with this time duration value? If not, please provide an alternative value and supporting information in the comments. Yes: Comments: The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP’s view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments.		
Northeast Power Coordinating Council, Inc.	Negative	Generator frequency ride-through capability is too lenient and will may not be feasible within the NPCC footprint. Â· **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards, In the interest of accommodating regional differences, the SDT solicited region-specific off nominal frequency requirements to be incorporated into PRC-024 Attachment 1. Curves specific to the Quebec Interconnection and to WECC have been added** The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. Â· **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard. In developing PRC-024-1, the SDT believes that the new standard enhances reliability principles as future generation will be required to meet requirements that many existing generation facilities do not have to meet.**
Response: Thank you for your comments. See specific responses above.		
Commonwealth of Massachusetts Department of Public Utilities	Negative	Generator frequency ride-through capacity is too lenient and will not work within the NPCC footprint. **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards, In the interest of accommodating regional differences, the SDT solicited region-specific off nominal frequency requirements to be incorporated into PRC-024 Attachment 1. Curves specific to the Quebec Interconnection and to WECC have been added** The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT believes that Generator Owners should be allowed to base protection system settings on site-specific fault clearing conditions. This is consistent with the requirements in FERC Order 661-A.** The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is

Organization	Yes or No	Question 5 Comment
		not a good practice and could lead to a proliferation of SPS installations. **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard. In developing PRC-024-1, the SDT believes that the new standard enhances reliability principles as future generation will be required to meet requirements that many existing generation facilities do not have to meet.**
Response: Thank you for your comments. See specific responses above.		
	Negative	My negative vote is baseed on the following: The generator ride-through capability is not sufficient and is too lenient. **Regional Entities are allowed to set requirements that are more stringent than those set in continent-wide NERC standards,** The standard needs to specify voltage relay setting requirements that include ensuring the settings are based on the actual fault clearing times of the installed circuit breakers recognizing the clearing times of the circuit breakers that are in-service on the BES. **The wording in Requirement R2 allows settings based on actual fault clearing times and voltage recovery profile if these can be provided by the Transmission Planner. In lieu of this the Generator Owner must allow for the full “no trip zone” envelope in PRC-024 Attachment 2.** The wording in the standard appears to approve the use of an SPS rather than meeting the requirements of the standard. An SPS should only be used as a limited/short time reliability resolve. Multiple Special Protetions Systems within an Area/Region risk safe and reliable operation of the Area's/Region's BES. **Special Protection Schemes (SPS) are intended to maintain transmission system reliability/security requirements following system disturbances not to subvert the requirements for voltage or frequency ride through requirements of a generator. (Note: As SPS are added, they are required to meet the requirements of PRC-015-1.) SPS requirements should not be used to avoid PRC-024-1 requirements as not every system disturbance affecting a given generator would result in initiation of the SPS.** New generating units that interconnect with the BES must meet all requirements of the standard. Standards should no longer be written to include a list of acceptable exemptions. If the generating unit is unable to meet

Organization	Yes or No	Question 5 Comment
		each and every standard requirement, it should not be permitted to interconnect to the BES. **PRC-024-1 does not include any exemptions for new generating units, but rather, the standard includes clarifications relative to the application of the standard. These clarifications have been included to assure consistency in the application of the standard.**
Response: Thank you for your comments. See specific responses above.		
Tennessee Valley Authority	Negative	The ride through criteria should not be anything beyond currently used critical clearing times (2nd zone protection or breaker failure) that switchyard breaker failure protection is based on. It is questionable whether large steam plants can survive anything beyond this. Plants with aux power systems normally fed from the switchyard would be even more questionable as the transient is not shielded by the action of the voltage regulator for the generator. **Actual clearing time (generally less than the critical clearing time) for a zone 1 three-phase fault, not to exceed 9 cycles was selected by the SDT, as a fixed 9 cycles could exceed critical clearing times for a given generating plant. The SDT is well aware of issues relative to potential steam plant auxiliary load tripping following a disturbance. Under the requirements of this standard, new generating plants will need to be designed to mitigate auxiliary load tripping.** For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. **The SDT considered inputs from major turbine manufacturers in developing the off nominal frequency requirements. Existing generating units that cannot meet a portion of the "no trip zone" in PRC-024 Attachment 1 can receive an exemption by documenting the technical limitation per Requirement R3,** For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. **Voltage ride-through requirements defined in the standard were determined based on a three-phase zone 1 transmission fault with normal clearing (which implies normal communication and breaker operation). Breaker failure analysis relative to Figure 2 is considered beyond the scope of this standard.** Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2. **NERC Standard NUC-001-2 addresses steady state interface requirements while PRC-024-1 addresses transient conditions. Some of the wording in PRC-024-1 has been modified to address nuclear-specific regulatory issues.**
Response: Thank you for your comments. See specific responses above.		

Organization	Yes or No	Question 5 Comment
SERC Generation Sub-committee (GS)	No	Comments: The GS proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
SPP Reliability Standards Develpment Team	No	We would like to see the technical background/justification of why the timeframe of 600s was chosen. We understand seeing the reasoning to expand it from 4s, but 600s (10 Minutes) seems extremely too long for voltage recovery. From a planning perspective 15 cycles (.25seconds) is standard for voltage recovery. Holding .9 from 3s to 600s could prove difficult if full load on unit and might not be enough bandwidth before you hit a loss of field relay. If enough current is provided to the field it will cause this relay to trip instantaneously. Not sure that taking a 10% hit during this instance will work.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. When the transmission system voltage is low, generators operating in AVR will be at a lagging power factor (delivering reactive power to the system). They should be a long way from the operating characteristic of a Loss of Field relay.		
LG&E and KU Energy	No	LG&E and KU Energy agrees with the SERC Generation Subcommittee and proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Santee Cooper	No	The LVRT portion of the curve between 0.4 secs and 3.0 secs should be 0.90 voltage PU. Electrical powered devices at the plant will begin to loose their ride-thru capability in the window of 0.2 to 0.65 seconds (as

Organization	Yes or No	Question 5 Comment
		referenced in the AREVA whitepaper on PRC-024 and based on industry experience)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Public Service Enterprise Group	No	Typical OEM recommended protective relay settings for generator UV are significantly more stringent than that which is outlined in Attachment 2 of the draft standard. Intuitively, it would seem that a generator and its auxiliary connect loads having the requirements to ride out 0.7 pu voltage for a period of 2 seconds is unrealistic.
Response: Thank you for your comments. The voltage duration curves in PRC-024 Attachment 2 are set at the point of interconnection with the transmission system. The generator will experience a different voltage depending on the specific characteristics of the generator, step-up transformer, and transmission system. IEEE does not recommend activating undervoltage protection for generators. If the Generator Owner chooses to activate this protection, it must be set to allow the transmission system to clear a fault and for the voltage to recover. For new generation facilities (designed and built after PRC-024-1 is implemented) the SDT believes auxiliary systems can be designed so that they will ride through the voltage excursions described in the standard.		
PPL Supply	No	Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Response: Thank you for your comments. The SDT agrees that the curves in PRC-024 Attachment 2 extend to 1000 seconds, but the period after 600 seconds is within the normal operating band of 95 – 105%.		
TVA - GO	No	TVA proposes that the LVRT portion of the curve between 0.4 secs and 3.0 secs be changed to 0.90 PU voltage. Electrical powered devices at the plant can begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience.)
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>Westar Energy</td><td>No</td><td>We suggest that the SDT provide the technical justification for this time duration. We do not agree with the time duration of up to 600 seconds. This time duration appears to be significantly long for voltage recovery. From a planning perspective, 15 cycles or 0.25 seconds is standard for voltage recovery. Holding 0.9 from 3 seconds to 600 seconds could be difficult if there is full load on the unit. There may not be enough bandwidth before a loss of field relay occurs. If enough current is provided to the field, it will cause the relay to trip instantaneously. FERC pro-forma Generator Interconnection Agreement requirements should also be considered in the development of the attachment.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The “No Trip Zone” within the Voltage Ride-Through Time Duration Curve defines the maximum time that a voltage at a given level would be expected. When the transmission system voltage is low, generators operating in AVR will be at a lagging power factor (delivering reactive power to the system). They should be a long way from the operating characteristic of a Loss of Field relay.   The SDT does not believe there will be conflicts between the pro-forma Generator Interconnection Agreement requirements and the requirements of this standard.</td></tr>
<tr><td>Luminant Power</td><td>No</td><td>Luminant believes the settings are reasonable and achievable for relay settings only.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.</td></tr>
<tr><td>Progress Energy</td><td>No</td><td>The ride through capabilities should be within the IEEE and ANSI C84.1-2006 “American National Standard for Electric Power Systems and Equipment - Voltage Ratings (60Hz)”. Standards associated with manufacturing electrical equipment</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. ANSI C84.1-2006 addresses the requirements for continuously supplied voltages, while PRC-024-1 addresses transient conditions.</td></tr>
<tr><td>Westinghouse</td><td>No</td><td>Due to the excessive duration of the +/- 10% voltage excursion, it is uncertain that many new manufactured turbine generators will be able to meet the V/HZ limits set by the manufacturers. Detailed studies would need to be performed to determine the ability of newer turbine generators to ride through these conditions.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The SDT reviewed the V/Hz limits in place for existing generating equipment and found that they were outside of the “no trip zone” boundaries set by PRC-024 Attachment 2 when evaluated at 60 Hz. The SDT recognizes that under conditions of a low frequency excursion coupled with a voltage transient, the resulting V/Hz condition experienced by the generation facility could exceed equipment limitations. The SDT considers a resulting trip to protect the equipment would not be a violation of the standard.</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Southern Company	No	1) The 600 seconds for +/- 10% voltage excursion is excessive. GE has published recommended generator permissible V/Hz settings for a stairstep protective solutions of not allowing > 118% V/Hz to exist longer than 2 seconds, and not allowing > 110% V/Hz to exist longer than 45 seconds. The HVRT curve requires allowing 110% V/Hz for 10 minutes, which is much longer. **The voltage duration curves in PRC-024 Attachment 2 are defined at the point of interconnection with the transmission system. The SDT expects that when the transmission system voltage is high, a generator operating under AVR would be at a lower voltage due to operation of the AVR and the impedance of the step-up transformer.** 2) Generators need a generator side excursion curve to even see if this is feasible. **The voltage at the generator terminals is highly dependent on the characteristics of a the particular generator, its step-up transformer and the transmission system at the particular location. All industry ride-through standards define voltage excursions at the transmission level.** 3) We believe a detailed study needs to be conducted by the industry for typical power plant designs to help determine the feasibility of power plants being able to ride through these extreme voltage conditions. We believe this study will demonstrate that this will not be possible without major re-design of power plant systems and components. **As the ride-through performance requirement will be applicable only to new generation facilities designed and built following approval of the standard, many of the issues raised should not be an issues relative to compliance with PRC-024-1. The SDT believes that future generating plants designs should be able to meet the standard.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	No	In studying PRC-024 Attachment 2, PacifiCorp believes that the “high voltage duration” curve, which defines the upper edge of the no trip envelope by depicting a 1.10 pu voltage between 1 second and 600 seconds, may potentially conflict with the synchronous generator Inverse-Time V/HZ Relay with Fixed-Time Unit setting recommendations contained in IEEE Std C37-102. For example: At 110% V/Hz, the relay will trip in 291.6 seconds (within the PRC-024-1 No Trip Zone). Additionally, at 109% the setting would be at 1166.4 seconds. PacifiCorp requests that the Standards Drafting Team (“SDT”) further evaluate PRC-024 Attachment 2 to determine if an adjustment to the high voltage duration curve could eliminate this potential conflict.
Response: Thank you for your comments. The voltage duration curves in PRC-024 Attachment 2 are defined at the point of interconnection with the transmission system. The SDT expects that when the transmission system voltage is high, a generator operating under AVR would be at a lower voltage due to operation of the AVR and the impedance of the step-up transformer. The SDT does not believe there will be a conflict with equipment V/Hz limits when evaluated at 60 Hz.		

Organization	Yes or No	Question 5 Comment
Duke Energy	No	The LVRT portion of the curve between 0.4 seconds and 3.0 seconds should be 0.90 voltage PU. Electrical powered devices at the plant will begin to lose their ride-thru capability in the window of 0.2 to 0.65 seconds (as referenced in the AREVA whitepaper on PRC-024 and based on industry experience).
Response: Thank you for your comments. The white paper provided by AREVA provides an excellent review of the impacts of transmission voltage perturbations on synchronous generating plants. As the performance requirement will be applicable to only new generation facilities that will be in-service following approval of the standard, many of the issues raised by AREVA are not applicable to the standard. As AREVA noted in their white paper that *"AREVA designs our new plant power systems with voltage regulators capability to support long-term variations in transmission system voltages,"* the SDT is confident that future generating plants designs should be able to meet the standard.		
Luminant Energy	No	The LVRT chart should only be limited by values pertaining to a system fault condition as a result of primary and backup transmission line relaying trip times (usually 0-30 cycles)
Response: Thank you for your comments. Voltage ride-through requirements defined in the standard were determined based on a three-phase zone 1 transmission fault with normal clearing (which implies normal communication and breaker operation). Breaker failure analysis relative to Figure 2 is considered beyond the scope of this standard.		
Ameren	No	This 90% and 110% ride through times should be longer to handle contingency periods of high voltage during light load conditions or periods where large VAr resources are lost during peak loads. Per our Transmission Planning department high voltages of 110% have been experienced for up to 8hrs.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed.		
American Electric Power	No	We agree that a new generating unit reasonably could be required to ride-though 90 percent or 110 percent voltage at the point of interconnection for 600 seconds at nominal frequency. However, this does not take away from the concerns expressed in response to Q4.
Response: Thank you for your comments. See the SDT response to your comments on Question 4.		
Tacoma Power	No	The required voltage and frequency settings should be determined by the interconnecting entities regional off nominal voltage and frequency plans.
Response: Thank you for your comments. The SDT agrees that the Generator Owner should set protection systems to meet regional as well as NERC requirements.		

Organization	Yes or No	Question 5 Comment
PPL Electric Utilities	No	Att. 2 extends to 1000 sec in the present draft of PRC-024, with 600 sec at +/- 10% voltage. See our comments above for question 4.
Response: Thank you for your comments. The SDT agrees that the curves in PRC-024 Attachment 2 extend to 1000 seconds, but the period after 600 seconds is within the normal operating band of 95 – 105%.		
CenterPoint Energy	No	(a) CenterPoint Energy agrees with the time duration value of the 0.9 pu voltage level up to 600 seconds and believes this will coordinate with existing undervoltage load shedding systems (UVLS). However, CenterPoint Energy believes there are numerous relays presently set at 2.0 seconds and 3.0 seconds to shed load in a voltage excursion and, therefore, there is not a sufficient margin for coordination at the two second and three second low voltage points in Attachment 2. CenterPoint Energy recommends these two points in Attachment 2 be revised to 2.5 and 3.5 seconds. That is, the data points (Time / Voltage) in the LVRT DURATION table would be as follows: 0.15 / 0.000, 0.30 / 0.450, 2.50 / 0.650, 3.50 / 0.750, and 600 / 0.900.(b) In addition, CenterPoint Energy believes there is insufficient margin at 1.0 seconds for high voltage ride through due to voltage over-shoot following a zone 1 fault. To provide an adequate margin, CenterPoint Energy recommends the 1.0 second high voltage point in Attachment 2 be revised to 1.5 seconds. That is, the data points (Time / Voltage) in the HVRT DURATION table would be as follows: 0.20 / 1.200, 0.50 / 1.175, 1.50 / 1.150, and 600 / 1.100.
Response: Thank you for your comments. The SDT realizes that there may be existing relays that could trip during an excursion as defined by PRC-024 Attachment 2, but could be set differently without compromising the protected equipment. The SDT would need better technical justification to change the curves.		
GenOn Energy	No	10 minutes is a long time for some unavoidable configuration of electrical auxiliaries.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed.		
Austin Energy		The equipment impact of this new requirement requires additional internal review before AE can respond definitively. If the requirement can be implemented without equipment risk, it will take up to 3 years to implement the new settings.
Response: Thank you for your comments. The SDT has extended the implementation of Requirement R6 to six years to allow for the development of designs that meet the Requirement.		

Organization	Yes or No	Question 5 Comment
Exelon	Yes	Most nuclear units will not be able to meet the time duration of "up to 600 seconds" unless they have an installed Load Tap Changer (LTC). This is due to the NRC required Degraded Voltage relay protection. The purpose of degraded voltage relaying is to protect emergency buses that feed equipment necessary for safe nuclear plant shutdown during an emergency or transient.
Response: Thank you for your comments. Existing generating units (including nuclear units) that cannot meet a portion of the "no trip zone" in PRC-024 Attachment 2 can receive an exemption by documenting the technical limitation per Requirement R3,		
ISO New England Inc.	Yes	Although the time duration is acceptable ISO-NE does not agree with the band shown. See our comments on Question 1, above.
Response: Thank you for your comments. See the SDT response to your comments on Question 1.		
Ingleside Cogeneration LP	Yes	The voltage ride-through specifications are reasonable for new generating facilities in Ingleside Cogeneration LP's view. Existing facilities that cannot meet this specification must be able to document an equipment limitation as allowed in R3.
Response: Thank you for your comments.		
Dynamics Review Subcommittee	Yes	While we agree, a technical basis for this 600 secs. duration (and each breakpoint) would be helpful.
Response: Thank you for your comments. The 600 seconds (10 minutes) was determined based on the anticipated time periods for automatic and manual (operator) system adjustments which should have taken effect and been completed. The breakpoints were developed after review of FERC Order 661-A, various European grid standards, and voltage profiles from simulations done in the WECC and SERC regions.		
MRO's NERC Standards Review Forum	Yes	Do not have an alternative value to suggest.
Northeast Power Coordinating Council	Yes	
Imperial Irrigation District (IID)	Yes	
BC Hydro and Power Authority	Yes	

Organization	Yes or No	Question 5 Comment
Idaho Power - Power Production	Yes	
Electric Market Policy	Yes	
NERC Staff Technical Review Team	Yes	
Arizona Public Service Company	Yes	
American Wind Energy Association	Yes	
Tri-State Generation and Transmission, Inc.	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery Company LLC	Yes	
New York Power Authority	Yes	
Puget Sound Energy	Yes	
Xcel Energy	Yes	
Great River Energy	Yes	
US Army Corps of Engineers	Yes	
RFC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	

Organization	Yes or No	Question 5 Comment
GE Energy	Yes	
American Transmission Company	Yes	
Hydro-Quebec TransEnergie	Yes	

6. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Consideration: Many of the comments provided are duplications of comments provided in response to the other five questions. There are not any new concerns raised by a large number of stakeholders.

Organization	Yes or No	Question 6 Comment
Ameren Energy Marketing Co.; Amerenue; Ameren Services	Negative	(6)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? **The SDT feels that allowing 10% of small generators to trip is fair because it is similar to a large unit experiencing a run back following an event. Runbacks do not result in a compliance violation.** (7)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. **Requirements R1 and R2 apply only to the generator protection system as stated in the Footnote 1. Requirement 6 applies to the performance of the entire facility, not just the generator protection system.** (8)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities? **This standard does not set requirements for the protection of the transmission system. If the voltage profile at a specific generating site exceeds the requirements of Attachment #2, then the generator(s) at that site would not be out of compliance if they tripped.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Negative	o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate**

Organization	Yes or No	Question 6 Comment
		capacity greater than 10%. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**
Response: Thank you for your comments. See specific responses above.		
MidAmerican Energy Co.	Negative	Comment: Given the number and depth of comments at the NERC webinar, it is clear the NERC standard is not clear or enforceable. This will generate the need for interpretations and Compliance Application Notices which cause further confusion and enforcement issues. Technical issues are also present. It is clear that NERC standards have not been coordinated with nuclear plant NRC standards and that conflicts will result. It seems likely that many nuclear plants will have trouble meeting the new standard and performance curves. Other power plants may not be able to upgrade the many subsystems required to ensure that a plant never trips for the PRC-024 standard given in the implementation period.
Response: Thank you for your comments. Existing plants, including those in design or construction phase when this standard goes into effect, do not have to meet Requirement R6 (the performance requirement). If there are technical limitations why their protection systems cannot be set so that they operate outside of the No Trip Zones of Attachments #1 and #2, then per Requirement R3 they must document the limitation and inform the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner of the limitation.		
Constellation Energy Commodities Group; Constellation Power Source Generation, Inc.	Negative	Constellation Energy Commodites Group believes that the 7 Requirements in this standard can be condensed into a single requirement simply stating that a generator must have frequency and voltage protection set per the curves in the attachments. However, it should be noted that even if a relay is set to operate according to the curves in the attachments, a minute deviation will exist in the operation of the relay, and as such, a protection system may operate in what the SDT has deemed the "no trip zone." If a relay operates in that zone, then an entity will technically be out of compliance with this standard even though it set its protection system correctly as per this standard. An allowable tolerance needs to be including in the requirements in order to capture real world conditions.
Response: Thank you for your comments. The Drafting Team believes more than one requirement is needed, both to meet the directives of Order 693 and the Blackout Report and for clarity.		

Organization	Yes or No	Question 6 Comment
Cowlitz County PUD	Negative	Cowlitz defers to WECC comments.
Response: Thank you for your comments. Please refer to the response to WECC.		
Dominion Resources Services	Negative	Dominion submits a negative ballot for the following technical reasons: 1. Do not understand R3 bullets. How does increasing your units rating by =10% change this? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** 2. Attachment 2 does not match the Â±5% voltage schedule per the definition of Voltage Excursion. This curve is not possible. **The definition of Voltage Excursion has been removed. PRC-024 Attachment 2 defines the outer boundaries of a voltage excursion. The SDT realizes that an actual excursion will never follow these boundaries, but as long as the excursion remains inside the boundaries, the generator protection system should not operate.** 3. R6 grants new generators exceptions. Where are the exceptions for existing generators? **Requirement R6 only applies to new generators. Existing generators are allowed exemption from portions of R1 and R2 if they can document technical limitations to their equipment as defined in Requirement R3.** 4. This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of applicability. **The Attachments define the boundaries of the excursions. The SDT does not understand how the requirements create more stringent criteria.**
Response: Thank you for your comments. See specific responses above.		
Liberty Electric Power LLC	Negative	Due to the need for changes to the underlying standard.
Response: Thank you for your comments. Changes have been made to the standard.		
Balancing Authority of Northern California NCR11118; Sacramento Municipal Utility District	Negative	For Requirement 5.2 what does it mean to provide an estimate of performance in 25% increments? Specifying an estimate lends itself to varying interpretations, confusion and judgments. **The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability.** Please consider the unit size and applicability for Requirement 6 to coincide with the development of the BES proposed definition. **The applicability for Requirement R6 is for Generator Owners. This is not affected**

Organization	Yes or No	Question 6 Comment
		by the definition of BES. The facilities that will have to comply with Requirement R6 are only new facilities that begin design, construction, and operation after this standard goes into effect. Requirement 7 dictates that generator trip settings be provided to the RC, PC, TO and TP when any request is made, is the response for the written request necessary for all four entities or just the requesting party? **The SDT agrees that the wording in Requirement R7 was confusing and has revised the wording to clarify the intent.**
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Negative	In addition to the feedback noted in the comments submitted via the NERC comment process, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).** (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1

Organization	Yes or No	Question 6 Comment
		fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.** o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. . **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**
Response: Thank you for your comments. See specific responses above.		
Brazos Electric Power Cooperative, Inc.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **The events studied are documented in the WECC White Paper listed in Section G, References. This is**

Organization	Yes or No	Question 6 Comment
		available on the WECC web site. The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point **The curves in Attachment 1 were developed in coordination with the PRC-006 SDT which is now approved by the NERC Board of Trustees. You will note that the Generator Protection curves in PRC-006 Attachment 1 match the curves in PRC-024 Attachment 1. A Regional Variance has been added to ensure the standard coordinates with the WECC UFLS program.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.**
Response: Thank you for your comments. See specific responses above.		
North Carolina Electric Membership Corp.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS

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		will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** It is not clear why the exception for R1 and R2 would expire with a capacity up-rate greater than 10% in R3. That implies that the reason for the exception must be fixed with such a capacity up-rate. Was this the SDT's purpose? Why? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Requirement R4 is unnecessary and completely administrative. It provides no reliability value. It appears to be an attempt to compel a Generation Owner to be responsive to its Reliability Coordinator, Planning Coordinator,Transmission Operator and Transmission Planner. In fact, it does not compel any real responsiveness as the Generation Owner could simply document their disagreement. It is already in the Generator Owner's best interest to be responsive. Thus, this requirement is not necessary. **The SDT agrees and has removed Requirement R4.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		
Old Dominion Electric Coop.	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We

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Response: Thank you for your comments. See specific responses above.		
Southwest Transmission Cooperative, Inc.; Sunflower Electric Power Corporation	Negative	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it. The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not

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Response: Thank you for your comments. See specific responses above.		

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Nebraska Public Power District	Negative	NPPD supports the comments submitted by the Midwest Reliability Organization (MRO) NERC Standards Review Forum (NSRF).
Response: Thank you for your comment. See response to the MRO NSRF.		
Liberty Electric Power LLC	Negative	Objection to the use of the word "inclusive" with the trip points for frequency relaying.
Response: Thank you for your comment. The word has been removed and an explanatory note has been added to each of the Attachments indicating that the No Trip Zone is exclusive of the lines, so setting relays to operate on a line is acceptable.		
Omaha Public Power District	Negative	OPPD is concerned with the rate of frequency change setting requested by R1.5 and would ask the SDT for justification behind the 2.5 Hz/Sec rate of frequency change. Further, some units may not be compliant to the frequency capability and voltage ride-through time duration curves requested by this standard. These technical limitations will prevent strict compliance to the standard as written.
Response: Thank you for your comments. R1.5 allows tripping if the rate of change of frequency exceeds 2.5 Hz/sec. It does not require tripping. This allows generators to have Aurora Scenario protection, which uses frequency rate of change as part of the detection scheme. The value 2.5 Hz/sec is commonly used in this type of protection. Existing generating units that cannot meet Requirements R1 or R2 for a technical limitation are allowed an exemption from the portions of Attachments 1 and 2 that the limitation prevents them from meeting. In order to receive this exemption, they must perform the actions described in Requirement R3.		
Northeast Utilities	Negative	Opposed with comments: 1) Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2) The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** 3) The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO**

Organization	Yes or No	Question 6 Comment
		criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements. 4) The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Portland General Electric Co.	Negative	Per WECC Position Paper
Response: Thank you for your comments. See response to WECC.		
SERC Reliability Corporation	Negative	Please see comments of the SERC Dynamics Review Subcommittee and the SERC Generator Subcommittee.
Response: Thank you for your comments. See response to the SERC Dynamics Review Subcommittee and the SERC Generator Subcommittee.		
ISO New England, Inc.	Negative	Please see detailed comments submitted. Of specific concern, we are voting negative due to: 1. Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2. The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** 3. The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024**

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		requirements. 4. The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Wisconsin Energy Corp.	Negative	R1.5 requires generator relaying to not trip for a rate of change of frequency of 2.5 Hz/Second. The requirement to be able to detect the rate of change of frequency is not achievable with existing equipment, and therefore should be removed. Also, the need for the information in R5 is not sufficient to make this a Requirement in this Standard. This information can be provided by informal means.
Response: Thank you for your comments. R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec. There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function.		
Florida Municipal Power Pool	Negative	R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied?
Response: Thank you for your comments. The intent is nameplate capacity. The wording has been changed accordingly.		
Public Utility District No. 1 of Chelan County	Negative	Requirement R1 of the proposed PRC-024-1 reliability standard conflicts with the WECC Off-Nominal Frequency Load Shedding Plan (WECC Coordinated Plan), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC regional Variance needs to be added to this draft.
Response: Thank you for your comments. A Regional Variance has been added for WECC.		
Minnkota Power Coop. Inc.	Negative	See comments of NSRF
Response: Thank you for your comment. See response to the MRO NSRF.		

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National Association of Regulatory Utility Commissioners	Negative	The following issues have been identified by the NPCC and need to be resolved: Â· Generator frequency ride-through capability is too lenient and will not work within the NPCC footprint. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** Â· The standard infers that the voltage relay settings should be based on actual fault clearing times. ISO New England maintains that the settings should be 9 cycles since clearing times may vary over time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing.** Â· The standard appears to allow a SPS to be used instead of meeting the requirements of the standard. This is not a good practice and could lead to a proliferation of SPS installations. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements.** Â· The standard provides for a number of exceptions for new generating units. New units should meet the standard in its entirety without exception. Standards should not be written in this manner which is contrary to reliability principals. **Requirement R6 sets expectations for new generating units that are far more challenging than those for existing units. The SDT believes this requirement will increase reliability while recognizing the realities of operating generating facilities.**
Response: Thank you for your comments. See specific responses above.		
Northern Indiana Public Service Co.	Negative	The related Standard Drafting subteams held a webinar on July 29 where they fielded numerous questions; issues still need to be addressed
Response: Thank you for your comments. The wording in the standard has been revised to improve clarity and remove ambiguities.		
Luminant Energy	Negative	The standard should not be addressing loadability issues as they are being evaluated in PRC-023-2. This standard should apply to generator protective relaying and its ability to ride through fault conditions.
Response: Thank you for your comments. The voltage curves in PRC-024 Attachment 2 do not require evaluating operation at 0.85 pu voltage for an extended period of time, as does PRC-023-2. Any relays that can meet PRC-023-2 requirements, will also meet the requirement the requirement to		

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operate at 0.90 pu voltage for an extended period.		
Lakeland Electric	Negative	The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment".
Response: Thank you for your comments. The SDT has revised the wording to make it consistent.		
Public Utility District No. 1 of Lewis County	Negative	This is another standard that should be reserved for generators larger that 100MW. Smaller generators should be exempt from frequency standards. Our plant only has a planel board frequency meter; no relaying or recording of frequency.
Response: Thank you for your comments. Without strong technical justification for changing the applicability, the SDT must use the Registry Criteria sizes (individual units 20 MVA or greater and facilities with aggregate size of 75 MVA or greater). Footnote 1 clearly states that the Generator Owner does not have to install or activate protection. If a generating unit does not have protective functions that trip the generator for frequency excursions, then it meets Requirement R1 by default.		
PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; Public Service Electric and Gas Co.	Negative	This standard has made progress, but there are ambiguities that we addressed in our comments and which the team also addressed on its July 29 Webinar. We recommend that the standard incorporate the suggested comments and the team repost the standard for a round of comments only.
Response: Thank you for your comments. The wording in the standard has been revised to improve clarity and remove ambiguities.		
Independent Electricity System Operator	Negative	We cannot support this standard for following reasons: i. Requirement R5: We do not support the requirement to provide an estimate of the performance of the units during frequency and voltage excursions. First of all, the requirement does not distinguish whether it applies to units that are equipped with frequency/voltage protective relays or otherwise. Secondly, the intent of providing the suggested estimate is to allow Transmission Planners to apply valid or supported assumptions in their planning studies. Given the requirements in Attachments 1 and 2, and Requirement R3 (which, by the way, should be modified as we suggest below), the TPs can apply the following relevant assumptions: a. For units that are equipped with frequency/voltage protective relays, the GO's submitted relay settings will determine when the units will trip; b. For units that are NOT equipped with frequency/voltage protective relays, the units are conservatively assumed to trip when the simulated frequency/voltage goes outside the bounds of Attachments 1 and 2. We do not see what other estimates that can be more relevant and valid than the above. We see that there may be some value in providing these estimates but only in the case of generators not equipped with frequency/voltage protective relays where tripping takes place beyond the no-trip zones of Attachments 1 and

Organization	Yes or No	Question 6 Comment
		2. For this information to be useful however, the generator's behavior must be predictable. While it may facilitate some "what-if" analysis, it is not clear that using this information would be better than the conservative assumption "b" above. How does the SDT envisage that the Transmission Planner will use this additional information if it cannot be relied upon? **The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability.** ii. R3: Please clarify the meaning of the expression "non-protection system equipment". Does it mean "a limitation imposed by equipment other than the protection system"? **SDT: Yes** Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? **SDT: No** In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the protective relays and ARE set at different thresholds. **If a unit does not have voltage or frequency protective relays, then by default it will not be tripped by such relays during an excursion and the GO is in compliance.** iii. We believe R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of "what" the response should entail. The "what" is stipulated in R3. **The SDT agrees and has removed Requirement R4.** iv. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. See specific responses above.		
Seattle City Light	Negative	We suggest that Requirement 5 be rewritten to require that the Generator Owner to provide the expected design performance of relaying and the performance results from a valid dynamic simulation. Requiring "estimates" of the probability of the generators remaining online after a severe fault seems arbitrary at best. It is unlikely that there is enough empiric evidence to form a valid statistical probability, and it is unclear what useful information a probability of the relaying design actually working would provide.
Response: Thank you for your comments. The "estimate of performance in 25% increments" portion of the requirement has been removed. The SDT agrees that it would not improve reliability.		
Beaches Energy Services; Lakeland Electric; City of Green Cove Springs; City of Vero Beach	Negative	What does "external to the plant" mean as used in several of the requirements (e.g., R1, R2, R6)? We assume that this would also mean beyond any radial connection (e.g., generator lead) to the plant and would suggest changing the term to something like: "caused by an event beyond the point at which the plant is radially connected to the transmission system". **Your assumption is correct.** Considering R1, many generators have speed protection embedded in control systems (e.g., a GE Mark V or VI), is that included in footnote 1 to the requirement in the phrase: "multi-function protective devices or protective functions within excitation controls that directly trip or provide tripping signals to the generator based on frequency or voltage inputs"? **The SDT agrees and has revised the wording in the footnote to clarify the intent.** In R2, does "voltage protective relaying" include station service protection, such as motor-contactors? The terms used in R1, R2 and R3 are inconsistent. R1 and R2 refer to "protective relaying", R3 refers to "protection system equipment". **The wording has been changed for consistency.** R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" the output between minimum and maximum output of the generator implied? **The intent is nameplate capacity. The wording has been changed accordingly.**.
Response: Thank you for your comments. See specific responses above.		
Brazos Electric Power Cooperative, Inc.	Negative	Requirements R1, R2 and R6 all should have Medium VRFs. In the long-term planning horizon, a VRF can be high if a violation "under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation or cascading". Requirements R1, R2 and R5 do not meet the "directly cause" condition as multiple violations of this standard would have to occur along with violations of other standards. The TPL standards already require the BES to be planned for contingencies of individual units as well Category C contingencies which will result in loss of multiple units at

Organization	Yes or No	Question 6 Comment
		the same plant. Additionally, TPL-004 requires the Transmission Planner and Planning Coordinator to study multiple events such as loss of a substation which could include loss of an entire generating plant. FAC-014-2 R6 requires the Planning Coordinator to identify the subset of multiple contingencies which result in stability limits. FAC-011-2 R3.3 requires the RC to determine which of these multiple contingencies qualify for use in the operating horizon. Then, of course, TOP-004-2 R1 requires the Transmission Operator to operate within the associated SOLs and IROLs and IRO-009-1 R4 requires the Reliability Coordinator to operate with IROLs. Thus, R1, R2, and R6 VRFs should be Medium. Requirement R4 does not have a VRF assigned.
Response: Thank you for your comments. This standard assumes a contingency has already occurred on the Transmission System to cause the voltage or frequency excursion. The loss of generation during a contingency could potentially lead to cascading outages. NERC defines this as a High VRF. Requirement R4 has been removed.		
Pacific Gas and Electric Company	Negative	The language contained in the VSL/VRF matrix must match the language in the Standard. Requirements R1 and R2 of PRC-024-1 require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that it does not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, would be non-compliant.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
PacifiCorp	Negative	(6) PacifiCorp offers one comment on the Violation Severity Limits (“VSLs”) proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
Arizona Public Service Co.	Negative	“Going from Lower VSL to Severe VSL, they are spaced 10 days apart. This is very unreasonable. They

Organization	Yes or No	Question 6 Comment
		should be spaced at least 30 to 90 days apart. The settings are used in studies for long range planning horizon and delay in information on relay setting of an individual unit is not significant to BES reliability. The drafting team should not follow generic guide lines and should use reasonability in setting these VSL levels."
Response: Thank you for your comments. The time increments are based on the NERC VSL Guidelines.		
Indiana Municipal Power Agency	Negative	IMPA does not agree with the VSLs for requirement 5 which is just an estimation of unit or plant performance. IMPA recommends lower the VSLs.
Response: Thank you for your comments. The risk factor for this requirement is "Lower". The VSL's are a measure of how severity of the violation. NERC requires that all VSL's contain a "Severe" level.		
Black Hills Corp	Negative	R1 & R2 require that frequency protective relaying & voltage protective relaying be set so that it does not trip within the criteria listed in the respective requirements "unless the GO has documented & communicated a non-protection system limitation in accordance with R3". However, the language of the binary Severe VSL for R1 & R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity coul be compliant with the language of R1 & R2, BUT based on the language of the VSL's, would be non-compliant.
Response: Thank you for your comments. The VSL's have been revised to address this issue.		
Florida Municipal Power Pool	Negative	R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning.
Response: Thank you for your comments. Requirement R4 has been removed.		
Sunflower Electric Power Corporation	Negative	Requirement R4 does not have a VRF assigned. Requirements R1, R2 and R6 all should have Medium VRFs. In the long-term planning horizon, a VRF can be high if a violation "under emergency, abnormal or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation or cascading". Requirements R1, R2 and R5 do not meet the "directly cause" condition as multiple violations of this standard would have to occur along with violations of other standards. The TPL standards already require the BES to be planned for contingencies of individual units as well Category C contingencies which will result in loss of multiple units at the same plant. Additionally, TPL-004 requires the Transmission Planner and Planning Coordinator to study multiple events such as loss of a substation which could include loss of an entire generating plant. FAC-014-2 R6 requires the Planning Coordinator to identify the subset of multiple contingencies which result in stability limits. FAC-011-2 R3.3 requires the RC to determine which of these multiple contingencies qualify for use in the operating horizon. Then, of course,

Organization	Yes or No	Question 6 Comment
		TOP-004-2 R1 requires the Transmission Operator to operate within the associated SOLs and IROLs and IRO-009-1 R4 requires the Reliability Coordinator to operate with IROLs. Thus, R1, R2, and R6 VRFs should be Medium.
Response: Thank you for your comments. Requirement R4 has been removed. This standard assumes a contingency has already occurred on the Transmission System to cause the voltage or frequency excursion. The loss of generation during a contingency could potentially lead to cascading outages. NERC defines this as a High VRF.		
Avista Corp.;BrightSource Energy, Inc.; City of Farmington; City of Redding; Cogentrix Energy, Inc.; Colorado Springs Utilities; Idaho Power Company; Los Angeles Department of Water & Power; Pacific Gas and Electric Company; South California Edison Company; Western Electricity Coordinating Council	Negative	Requirements R1 and R2 of PRC-024-1 require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that it does not trip within the criteria listed in the respective requirements “unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3.” However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, would be non-compliant.
Response: Thank you for your comments. The VSL’s have been revised to address this issue.		
MidAmerican Energy Co.	Negative	The standard nor VSL are ready
Response: Thank you for your comments. The standard has been revised to clarify intent and remove ambiguities.		
Independent Electricity System Operator	Negative	We do not agree with the standard as posted, for which we have casted a NO vote. We are unable to support the VRFs and VSLs for the standard/requirements that we reject, and we expect the standard to be materially revised which may result in corresponding changes to the VRFs and VSLs.
Response: Thank you for your comments. The standard has been revised to clarify intent and remove ambiguities.		
Beaches Energy Services; Lakeland Electric; City of Green Cove Springs; City of Vero Beach	Negative	R4 is missing the VRF and Time Horizon - would recommend Lower and Long-term Planning

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. Requirement R4 has been removed.		
Imperial Irrigation District (IID)	No	
Santee Cooper	No	
Westar Energy	No	
Luminant Power	No	
Westinghouse	No	
American Wind Energy Association	No	
Oncor Electric Delivery Company LLC	No	
New York Power Authority	No	
Dynegy Inc.	No	
Puget Sound Energy	No	
Austin Energy	No	
Xcel Energy	No	
South Carolina Electric and Gas	No	
Ingleside Cogeneration LP	No	
Tacoma Power	No	

Organization	Yes or No	Question 6 Comment
Manitoba Hydro	Affirmative	Manitoba Hydro is voting affirmative but justification should be provided by the drafting team for the curves in Attachments 1 and 2. It is not clear why the 'no trip zone' limits are set as they are.
Response: Thank you for your comments. The frequency curves in Attachment 1 match the generator tripping curves from PRC-006 and provide a margin for UFLS programs to operate before generator tripping occurs. The voltage profile in Attachment 2 was developed using information from FERC Order 661A and studies done in the WECC and SERC regions. The WECC White Paper on their studies is cited in the Reference Section.		
Southern Company Generation	Affirmative	R4 does not have a VRF assigned to it.
Response: Thank you for your comments. Requirement R4 has been removed.		
Texas Reliability Entity	Affirmative	The VSL for R6 refers to "Requirement 6" in connection with frequency parameters and to "Attachment 2" in connection with voltage parameters. It would be more direct and consistent to refer to "Attachment 1" in connection with frequency parameters.
Response: Thank you for your comments. The SDT agrees and has revised the VSL accordingly.		
Southwest Transmission Cooperative, Inc.	Affirmative	While we are voting affirmative for the VSLs and VRFs, conforming changes will be necessary if requirements our modified per our ballot comments.
Response: Thank you for your comments. If the Standard had passed the initial ballot, then there would not have been changes to the requirements.		
Pepco Holdings Incand Affiliates	Yes	1) The applicability section from the previous draft of this standard should be re-inserted. Although the SDT chose to remove that section since the standard is intended to apply to all generation facilities that meet Compliance Registry Criteria, adding the specific generation criteria for which this standard applies within the body of the standard provides much more clarity than having to refer to a second document to define applicability. In addition, inserting the full applicability criteria would be consistent with the way Applicable Facilities are identified in Section 4.2 of PRC-019-1. **Unless there are deviations from the Registry Criteria, NERC Staff has told the SDT to write the Applicability as currently drafted. PRC-019-1 deviates with the inclusion of synchronous condensers.** 2) Requirement R 2.1.1 should be re-worded as follows: "For three-phase faults with Normal Clearing on transmission system facilities (lines, busses, transformers, etc.) adjacent to the point of interconnection, set voltage relays to ride through expected fault clearing times, not to exceed 9 cycles." The use of the term "zone 1 faults" implies that zone 1 relaying schemes are always employed on the transmission system, which may not be the case. Pilot schemes, overcurrent schemes, differential schemes, etc. may be used instead.

Organization	Yes or No	Question 6 Comment
		Also, the unit should stay connected if a fault were to occur on an adjacent bus or transformer rather than just on lines. Also, use of the term "Zone 1 fault" in Requirement R5 needs to be similarly addressed. **Requirement R2, section 2.1.1 has been removed. Clarification #2 to PRC-024 Attachment 2 has been revised to state "The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal Clearing…"** 3) Requirement R 2.1.1 should also address ride through capability for TPL Category C contingencies (i.e. single line to ground faults with a stuck breaker, or other cause for delayed clearing) since generation units are expected to remain on line during these contingencies as well. Granted, a three phase fault would be the most severe, however a single line to ground fault with delayed clearing times could also cause unwanted unit tripping, leading to a violation of Reliability Criteria. **Although PRC-024 Attachment 2 curves were derived based on the voltage profile of normally cleared Zone 1 faults, the SDT believes they cover many other contingencies, including some, but not all, from TPL Category C. The SDT believes it is unrealistic to expect generators to be designed to accommodate all Category C contingencies at all possible generating sites.** 4) The SDT in their response to comments on Draft #1 of this standard stated that "Attachment 2 was developed based on a positive sequence model. As such, only balanced voltages should be considered when addressing relay settings." This is fine for evaluating the response to three phase faults, or other balanced system disturbances. However, if it is critical to the reliability of the BES to not have generators trip off line for voltage excursions associated with three phase faults, then it is equally as important to have them remain on-line for single line to ground faults, which are much more common. During a phase to ground fault at the point of interconnection the faulted phase voltage collapses to zero but the unfaulted phase to ground voltages could rise as high as 80% of the line to line voltage for an effectively grounded system (with a coefficient of grounding = 80%). This is well in excess of the 1.2 p.u. requirement shown in Attachment 2. Generator voltage protection relays respond to actual phase voltages not just positive sequence voltages. As such, for the unit to ride through phase to ground faults at the point of interconnection then the short time 1.2 p.u. overvoltage threshold needs to be raised above 0.8 x 1.73 = 1.38 p.u. **The SDT agrees and has added Clarification #5 to PRC-024 Attachment 2 that states: "Additionally, voltages in the curve assume minimum fundamental frequency phase-to-ground or phase-to-phase voltage for the low voltage duration curve and maximum crest phase-to-ground or phase-to-phase voltage for the high voltage duration curve".** 5) The revised language in R3 referring to "the equipment limitation expires coincident with ...." is unclear and confusing. How can the "limitation" expire merely by the generating unit continuous capacity rating being increased > 10%. The Draft #1 version of this standard uses the phrase "the Generator Owner is granted an exception for that unit meeting the portion of R1 or R2 for that limitation once it provides documentation of the equipment limitation(s)..." "This exception for the equipment limitation shall expire coincident with..." The use of the term "exception, or exemption", makes more sense and is more in line with the intent of this

Organization	Yes or No	Question 6 Comment
		section. As such, the original language from Requirement R5 from Draft #1 should be re-instated. **The SDT agrees and has restored the Draft #1 wording.** 6) Typically unit connected generator protection packages, which include frequency and voltage protective elements, are supplied by voltage transformers connected on the terminals of the generator rather than on the high side of the generator step-up (GSU) transformer. For frequency elements, the frequency at the terminals of the generator is the same as on the high side of the GSU transformer. So comparison of frequency protective element set points can be made directly with Attachment 1. However, this is not true for voltage. The generator terminal voltage could be higher, or lower, than the system voltage on the high side of the GSU transformer depending on the voltage drop across the transformer, which varies depending on the generator real power output and whether the generator is supplying or absorbing reactive power. Since this standard requires the generation to remain connected for specific voltage criteria as measured at the point of interconnection, but the voltage sensing protection is connected to the generator terminals, some technical guidance (with specific examples) must be provided to allow the Generator Owner to translate these voltage criteria to the voltages seen by the protective relays on the terminals of the generator. Otherwise an incorrect evaluation may result. It is recommended that a Technical Reference Document similar to the “Power Plant and Transmission System Protection Coordination” document developed by the NERC System Protection and Control Subcommittee be produced, or the above mentioned document revised, to provide illustrative examples of how to apply the Attachment 2 POI voltage criteria to voltage sensing protective elements connected to the terminals of the generator. **The SDT agrees that the voltage seen at the generator terminals will not be the same as at the point of interconnection where the excursion occurs. Normally, the voltage at the generator terminals will be higher during the fault due to the impedance of the Generator Step-Up transformer (typically in the neighborhood of 0.4 pu during a close-in three phase fault). The GO may conservatively evaluate protective functions with voltage inputs using the POI voltage profile with the assumption that if they ride through that profile they will ride through the voltage seen at the generator terminals. Alternatively, the GO may choose to do a dynamic simulation and evaluate based on the results of that study. There are a number of good texts available on system stability. The SDT does not feel the need to write another one.** 7) Comments on “Voltage Ride-Through Curve Clarifications” which appears on the last page of the standard:Item#1 - Suggest replacing the term “scheduled operating voltage” with “nominal operating voltage”. Voltage schedules may change over time, whereas “nominal” or “rated” voltages do not. Also, the protective systems are usually set based on voltage excursions above, or below, “rated” or “nominal” voltage. **The SDT agrees that “nominal” is better than “scheduled” and has changed the wording accordingly.** Item #2 - Suggest eliminating item 2. The ride-through curve is to ensure the unit remains on line for voltage excursions up to the limits defined by Attachment 2, regardless of the cause of the voltage excursion. **The SDT agrees and has changed Clarification #2 to PRC-024 Attachment 2 to read as follows: “The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal**

Organization	Yes or No	Question 6 Comment
		Clearing not to exceed 9 cycles.” Item #3 - The use of the term “cumulative voltage duration” is confusing since Attachment 2 is made up of a series of discrete allowable voltage magnitudes and durations. **The SDT intentionally used the word “cumulative” so that OEM’s will know how much time their equipment has to withstand any particular voltage level. It also gives relay setting engineers the ability to evaluate settings for different voltage levels at the specified duration times.** Also, the language only mentions voltage protective relaying and not other non-protective equipment, which could cause the unit to trip. Suggest re-wording as follows: “The generator shall remain connected (i.e., “ride-through”) voltage excursions caused by disturbances on the transmission system, when the voltage at the point of interconnection with the BES remains within the boundaries of these curves. **The SDT agrees and has added the words “…control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs…” to Footnote 1.** ”Item #5 d - suggest removing the term “scheduled”, making it read “d. Voltage is measured at the point of interconnection” **The SDT agrees and has removed part “d.”.**
Response: Thank you for your comments. See specific responses above.		
Northeast Power Coordinating Council	Yes	In R3, the SDT should review that generators are not required to provide a remedial plan for an equipment limitation. For the SDT’s consideration is the work done by and for the NPCC UFLS RSDT. It was recommended to retain the more conservative NPCC Frequency Capability Curve for setting generator protection as opposed to the proposed Frequency Capability Curve in PRC-024-1 for the following reasons:1. Some portions of the NPCC Region have additional stages of UFLS set at lower frequency thresholds below 58 Hz. Adopting the curve in Attachment 1 may impact the effectiveness of the UFLS program from arresting frequency decline in these depressed frequency ranges. **The frequency ride-through capability (Attachment 1) matches the generator tripping expectation from PRC-006 Attachment 1, which includes a margin from the UFLS Underfrequency Performance Characteristic defined in the same attachment. Any Regional Entity can set requirements that are more stringent than a NERC standard.** 2. As the numbers of distributed generators connected to the system increase, it is expected that overall generator frequency response is expected to be reduced. The distributed generation may also not need to comply with the generation trip thresholds as they may not meet the existing thresholds applicable to Generator Owners in NERC’s Statement of Compliance Registry Criteria. Adopting the proposed PRC-024-1 curve would jeopardize the survival of islands that may contain increasingly larger portions of distributed generation should the frequency decline below 58 Hz. **This Standard cannot extend applicability to distributed generation that is not within the Registry Criteria. There is a separate NERC project that is**

Organization	Yes or No	Question 6 Comment
		addressing frequency response. 3. Adopting the proposed PRC-024-1 curve reduces the probability that the UFLS program will successfully arrest declining frequency for system conditions that are not addressed in NPCC's 2006 UFLS Assessment. **The Attachment 1 curves matches the generator tripping curves in the recently-approved PRC-006 standard. These curves provide some margin beyond the UFLS performance required in PRC-006.** 4. Adopting the proposed PRC-024-1 curve would decrease the ability of an island to survive more severe conditions than those considered in the UFLS design (for example, islands with a generation deficiency greater than 25 percent). **The SDT agrees that this is possible, but feels there must be a balance between system security under extreme contingencies and destroying generating equipment by requiring operation for long periods of time at very low frequencies.**
Response: Thank you for your comments. See specific responses above.		
ACES Power Members	Yes	R3 is an unnecessary requirement. Enforcement of R1 and R2 already create a de facto requirement to document limitations. Thus, R3 creates an opportunity for double jeopardy.
Response: Thank you for your comments. The SDT disagrees that Requirements R1 and R2 create a de facto requirement to document limitations. Requirement R3 is included so that the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are aware of the documented limitation and can model the performance of the generator correctly when evaluating its performance during excursions.		
BC Hydro and Power Authority	Yes	1. R2 introduces Remedial Action Schemes (RAS) as an alternative description. We recommend keeping to Special Protection System and leaving RAS in the NERC glossary. **In one region the term "Remedial Action Scheme" is used instead of "Special Protection System". The SDT does not believe the use of the term "RAS" in this standard causes confusion.** 2. We recommend a consistent use of the terms Planning Coordinator and Planning Authority. In the Purpose of this standard, Planning Coordinators are referred to. In the NERC glossary, under Planning Coordinator it says "refer to Planning Authority". The compliance registry list includes a column for Planning Authorities. The NERC Reliability Functional Model version 5 discusses Planning Coordinators only. Is the term Planning Coordinator going to replace Planning Authority? **The NERC Functional Model does not contain a "Planning Authority". The Functional Model and this standard use "Planning Coordinator".**
Response: Thank you for your comments. See specific responses above.		
SERC Generation Sub-	Yes	During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant

Organization	Yes or No	Question 6 Comment
committee (GS)		performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: o Important Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform it's function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement.For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2."The comments expressed herein represent a consensus of the views of the above named members of the SERC Generation Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator's performance during an excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
Idaho Power - Power Production	Yes	In section 2.1.1, we believe that the "three phase transmission system zone 1 fault" should be clarified. Is the zone 1 referring to the generator relay backup zone 1 element? The zone 1 element of the interconnection station line protection relays? Shortest line? Longest line? Another zone 1? Also, the language was a little confusing, is this an if-then statement? Since the voltage ride through curve apparently applies to all conditions (both operating and various fault configuration), reference to the "three phase transmission system zone 1 fault" implies a limitation to applicability that is not intended, and the reference should be deleted. For R3, because the time horizon for this standard is long-term planning, we believe the 30 day communication requirement is not necessary. We believe 180 days is more in line with other reporting time frames with modeling related standards. We also believe that the equipment limitation expiration section is not needed. A simple statement stating that the when the limitation is no longer valid, the RC, PA, etc should be notified. For R6, we believe it is unnecessary to have different requirements for existing and new units. We do not see the need for performance requirements for new units. We believe this standard should be a relay settings

Organization	Yes or No	Question 6 Comment
		standard, with generator performance being considered in modeling standards. R7 is burdensome to both the Generator Owner and to the receiving entities, and also prone to causing confusion. The entities proposed to receive the protection settings (RC, PC, TO, TP) would face a difficult task to be able to properly interpret the relay settings sent. The Generator Owner is the proper entity to determine the relay settings to remain in compliance with the standard. In addition, the requirement to transmit the settings within 30 days of changes is burdensome and unnecessary. Draft PRC-019-1 properly address the issue of coordinating settings with machine capabilities, and PRC-001 properly addresses the issue coordinating settings with the TO.
Response: Thank you for your comments. See specific responses above.		
SPP Reliability Standards Develpment Team	Yes	Would like to see a more consistent approach to the comment forms and the standard. It seems there is room for clean up in the posted standard/comment form.
Response: Thank you for your comments. The SDT apologizes for the inconsistency between the comment form and the standard.		
MRO's NERC Standards Review Forum	Yes	It is not clear what the basis for the requirement of R3 with regard to a 10% or more increase in capacity would lead to an expiration of an equipment limitation as the change that results in the capacity increase may not be related in any way to the origin of the equipment limitation.
Response: Thank you for your comments. The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.		
Electric Market Policy	Yes	Dominion suggests the following:Section 3 should capitalize “frequency and voltage excursions”, as they are defined terms. **The definitions have been removed from the standard.** Do not understand R3 bullets. How does increasing your units rating by â‰¥10% change this? **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** Attachment 2 does not match Â±5 voltage schedule per the definition of Voltage Excursion. This curve is not possible. R6 grants new generators exceptions. Where are the exceptions for existing generators?This standard only applies to frequency and voltage excursions within the defined limits. The attachments and requirements go outside of this bound placing much more stringent criteria on the operation of the units. These more stringent criteria may not be possible and should be removed from the standard to align with the definition of

Organization	Yes or No	Question 6 Comment
		applicability. The last sentence of the associated Implementation Plan is confusing. Suggest revising to read: “Upon the effective date of PRC-024-1, R4 of PRC-006-1 will also go into effect.”
Response: Thank you for your comments. See specific responses above.		
Dynamics Review Subcommittee	Yes	Under R5, Severe VSL Requirement 55 should be Requirement 5.R7 refers to generator protection trip settings as "specified" in R1 & R2. Settings are not specified in R1 & R2. We recommend using "referred to" instead of "as specified.""“The comments expressed herein represent a consensus of the views of the above named members of the [insert the full name of the group] only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Response: Thank you for your comments. The SDT agrees and has revised the VSL’s accordingly.		
LG&E and KU Energy	Yes	LG&E and KU Energy would prefer to have 60 calendar days on
Response: Thank you for your comments. The SDT does not understand which requirement you are referring to.		
FirstEnergy	Yes	FirstEnergy offers the following additional comments and suggestions:Requirement R3 - It is not clear how this requirement relates to the identified generator equipment limitations. Furthermore we are not clear what “continuous capacity rating” is referring to. We suggest the removal of the second bullet which states “the generator unit continuous capacity rating increases >= 10%”. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.. The wording has been changed from “continuous capacity” to “nameplate” to clarify intent.** Requirement R3 - This standard does not account for the fact that nuclear plants have equipment other than the generator that potentially will trip the unit at frequencies/ voltages outside of the limits shown in Attachments 1 and 2. Nuclear plant voltage and frequency trip points are set to ensure safety equipment will operated as specified in the plant’s License. The standard needs to allow nuclear generators the ability to specify if something other than the generator protective relays dictates where a unit will trip. **The SDT believes that Requirement R3, as written, allows nuclear plants (or any others) to trip during a frequency or voltage excursion if the Generator Owner has documented these conditions. The intention of the SDT is that nuclear safety requirements do qualify as technical equipment limitations described in the requirement.** Under 6.7 (exception) - A unit or generating plant or generating Facility may trip if the protective functions

Organization	Yes or No	Question 6 Comment
		(such as out of step or loss of field functions) operate due to an impending or actual loss of synchronism or due to instability in power conversion control equipment. Maybe this section should include an exception for Volts/Hertz protection. **The SDT agrees and has made the wording more general to allow tripping to protect the equipment from damage.** General - The standard should state whether disturbances that include both frequency and voltage excursions are covered under the standard. For example, our Volts/Hertz protection trips in 45 seconds at 110%. The standard calls for a HVRT of 600 seconds at 110%. This current Volts/Hertz setting would not meet the standard. **The Clarifications to Attachment 2 state that the voltage excursions are to be evaluated at 60 Hz. In your example, the 600 seconds at 110% voltage is on the transmission system. Generators running in AVR voltage control mode behind a step-up transformer would be at a lower voltage due to the impedance of the transformer and operation of the AVR.**
Response: Thank you for your comments. See specific responses above.		
Public Service Enterprise Group	Yes	a. Per the July 29 webinar discussion, R2.1.1 needs to be rewritten for clarity. **The SDT agrees. This section has been revised to clarify intent.** b. The "exception" process in R3 and R4 is too vague as to "who" decides whether this standard applies to a generator. If a GO describes the limitations per R3 and one of the four entities listed in R4 inquires about a specific limitation, and the GO subsequently replies to that entity, is the exception confirmed? Under what circumstances a description of limitations by a GO in R3 would be challenged? Unless the exemption to this standard is made clear, the result will be confusion when the standard is approved. **The GO has the sole discretion in determining what equipment qualifies for a limitation under Requirement R3. There is no provision for a challenge. Requirement R4 has been removed.**
Response: Thank you for your comments. See specific responses above.		
PPL Supply	Yes	1. The term "continuous capacity rating" in the second bull-dot item of R3 should be replaced with "Normal Rating or Emergency Rating," to eliminate ambiguity via use of NERC Glossary-defined terms. **The SDT has determined that "nameplate" rating is more appropriate.** 2. The term "non-protection system" in R3 should be replaced with "non-Protection System," to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable) **The SDT agrees and has revised the wording to clarify intent.** 3. Paras. R5.1 and R5.2 suffer in terms of clarity. Suggest rewording these paragraphs to make them easier

Organization	Yes or No	Question 6 Comment
		to understand. **The SDT agrees and has revised the wording.** 4. An exception should be added for nuclear facilities that may not be able to ride through the frequency and voltage excursion outline in PRC-024 with out impact to nuclear safety systems. **Any existing facility (including nuclear) is allowed an exception to portions of the curves in Attachments 1 and 2 if they document the limitation and communicate the information described in Requirement R3.**
Response: Thank you for your comments. See specific responses above.		
Florida Municipal Power Agency	Yes	The bullets in R3 are onerous. The bullets would essentially eliminate the ability to replace like-with-like which would have an impact on spare equipment strategy and stores since existing spares in the warehouse could not be used. If spares were not available that could meet the new criteria, the GO would be forced to either keep a unit off-line or be non-compliant. FMPA suggests eliminating the bullet, or at most, institute something like a Cyber Security Technical Feasibility Exception (TFE) process. **The SDT disagrees since a like-for-like replacement would not result in a nameplate capacity increase, so the GO would be allowed to maintain its exception.** In addition, in the bullets at the end of R3, is the 10% incremental or cumulative over time? E.g., if a GO does a capacity augmentation of 5% one year and then another 5% increase 3 years later, does that trigger the 10%? **The intent is a cumulative increase. The wording has been revised to reflect the intent.** R6.1.1 is ambiguous, what does "at least 20% of the Facility's rated capacity" imply? Would a single test at full output suffice, or is "book-ending" between minimum and maximum output of the generator implied? **The intent is 20% of nameplate capacity. No testing or operational data would be needed to determine the value. The wording has been revised to reflect the intent.**
Response: Thank you for your comments. See specific responses above.		
NERC Staff Technical Review Team	Yes	The applicability section should be expanded to address both applicable entities and applicable facilities similar to MOD-025-2 and should apply to individual generating units >20 MVA (gross nameplate rating) and generating plants/Facilities >75 MVA (gross aggregate nameplate rating), regardless of interconnection voltage. **Unless there are deviations from the Registry Criteria, NERC Staff has told the SDT to write the Applicability as currently drafted.** The percentage of units that must be compliant in Effective Date sections 5.1.1, 5.2.1, and 5.3.1 should be based on an MVA basis similar to other standards in Project 2007-09, such that the phrase “% of its applicable units” is replaced with “% of its applicable units on an MVA basis. **The SDT does not see an advantage to using MVA basis as opposed to number of generating units. The intent of the three-year implementation plan is to allow any protective relay settings changes to be accomplished within**

Organization	Yes or No	Question 6 Comment
		normally scheduled maintenance outages. Using number of generating units allows Generator Owners a better chance to avoid having to schedule an outage specifically to implement changes required by this standard. ”The SDT should consider the implications of Requirement R1, part 1.5, which appears to preclude unit tripping when frequency rate-of-change is less than 2.5 Hz/s, even if the frequency is above 62.2 Hz or below 57.8 Hz. **The intent is to *allow* tripping within the No Trip Zone if the rate of change of frequency *exceeds* 2.5 Hz/sec. The wording has been changed to reflect the intent.** The voltage curves in Attachment 2 should be applicable for any operating condition that falls within the voltage-time curves regardless of the initiating event that causes the voltage excursion. As such, Requirement R2, part 2.1.1 should be removed from the standard. **The SDT agrees and has removed Requirement R2, part 2.1.1. In addition, it has revised PRC-024 Attachment 2, Clarification #2 to say “The curves depicted were derived from to a three-phase transmission system zone 1 faults with Normal Clearing not to exceed 9 cycles.”** Also, we understand from the webinar that the voltage curves in Attachment 2 represent positive sequence voltage. If voltage relays that sense phase-to-ground or phase-to-phase voltage are set according to this curve, generator tripping could occur for normally cleared unbalanced faults (e.g., the unfaulted phase voltage during a single-line-to-ground may exceed 1.2 per unit on an effectively grounded system). The drafting team must develop curves that can be used directly for setting protective relays to assure that generators remain connected for both balanced and unbalanced faults.System conditions may change more quickly than a Transmission Planner can identify and convey applicable voltage relay setting requirements to a Generator Owner. **The SDT has determined that “least phase voltage” for the low voltage portion of Attachment 2, and “greatest phase voltage” for the high voltage portion of Attachment 2 are more correct than “positive sequence voltage” and the wording has been changed accordingly.** We are not aware of any reason a Transmission Planner would require less stringent criteria than Attachment 2. For these reasons, the following items should be deleted:(1) Requirement R2, part 2.1.2;(2) The phrase referring to “the voltage profile at the Point of Interconnection for the generating unit or generating plant or Facility of the most severe normally-cleared Zone 1 fault . . .” in Requirement R5, parts 5.1 and 5.2;(3) Requirement R6, part 6.3; and (4) Note 2 to the Voltage Ride-Through Curve Clarifications.Equipment limitations will not change based on modifications to changes in generating unit capacity. **The SDT allows the Transmission Planner to provide a voltage profile to a Generator Owner based on the actual clearing times at that site. This may be less stringent than the curves in PRC-024 Attachment 2, but may not be more stringent.** The second sentence in Requirement R3 should be changed from “the equipment limitation expires . . .” to “The waiver for compliance with Requirements R1 and R2 associated with the equipment limitations expires .

Organization	Yes or No	Question 6 Comment
		The SDT agrees and has changed the wording accordingly. ”The conditions in Requirement R6, parts 6.1 and 6.2 could be interpreted to indicate that this requirement only applies to generating plants/Facilities greater than 75 MVA. The standard should be revised to be clear that it also applies to generating units greater than 20 MVA. **The SDT intent is that these 6.2 only apply to facilities with generating units <20 MVA that aggregate to >75 MVA. 6.1 is written without size designations, although 6.1.1 is written similarly to 6.2 with the same intent.**
Response: Thank you for your comments. See specific responses above.		
Bonneville Power Administration	Yes	The proposed standard uses both "zone 1" and "Zone 1", which we assume mean the same thing. What is the source of the Zone 1 determination?
Response: Thank you for your comments. The SDT used studies of normally cleared three-phase Zone 1 transmission system faults as the basis for developing the curves in PRC-024 Attachment 2 since this provided the most severe voltage profile. The curves in Attachment 2 are similar to those developed in FERC’s Order 661-A and various international grid codes.		
TVA - GO	Yes	During the drafting process, quite a bit of feed back was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated using the allowed operating bands developed as for use in relay setting coordination. The concerns with this include: o Important Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride through criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed? For frequency, the ride-thru criteria should be sufficient for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar steam turbine restrictions also apply for the high frequency requirement. For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly. Nuclear power plant interface requirements are addressed in NERC NUC-001-2. PRC-024 should refer to nuclear plant interface requirements managed under NUC-001-2.
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator’s performance during an		

Organization	Yes or No	Question 6 Comment
excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
Progress Energy	Yes	Forcing the utility to delay fault clearing (a three phase bolted fault at the point of interconnection causing a zero voltage) will increase the damage to the generation facility caused by the fault. Protective relay schemes have two primary objectives, to clear a fault rapidly to minimize the impact on the Bulk Electric System and to prevent (minimize) the damage to the faulted component and the components close to the faulted component. By forcing utilities to keep a generator feeding a fault of the magnitude implied by attachment 2 of PRC-024 the regulation may increase the costs of maintaining the generator. Additional inspections after a fault may be required to assure no internal damage occurred during the event that would not be required if the generator could be isolated from the fault more rapidly.
Response: Thank you for your comments. This standard does not set any requirements for the speed of fault clearing, but does allow a generator to trip if a close-in transmission fault is not cleared within nine cycles. Good utility practice has always assumed generators will feed fault current to allow protective relaying to sense faults and operate correctly. Even if the generator trips, it will have already seen fault current so any maintenance activities the owner chooses to perform as a result of the event would occur whether it trips or rides through.		
Southern Company	Yes	1) It is recommended to rephrase R4 so that the requirement (shall statement) is first and the conditions (within x of receiving a request) is second as follows: "The Generator Owner shall provide a written response within 90 calendar days of receipt of a written inquiry from the RC, PC, TOP, or TP regarding an equipment limitation identified in accordance with Requirement R3." More response time than 90 days is needed for cases were a written inquiry is given to a GO (with a very large number of units) for all units in one request. **The SDT has removed Requirement R4.** 2) We believe that the condition specified in R6.2 should be limited to PV plants and wind farms? **The SDT has been charged to write the standard in a technology-neutral manner. If R6.2 is allowed for wind farms and PV plants and not for an hydro facility with a number of small generators it would be discriminatory.** 3) Since Requirement R6 provides exceptions to the requirement (6.3 thru 6.7) these exceptions need to be mentioned in Measure M6. (add "unless one of the exceptions 6.3-6.7 apply" to the end of the sentence.) **The Measure refers to the Requirement, which includes all sub parts.** 4) Employing new grid frequency and voltage ride-through requirements may impact the licensing and design basis of nuclear facilities. NUC-001-1 requires coordination between Nuclear Plant Generator Operators and Transmission Entities for the purpose of ensuring nuclear plant safe operation and shutdown. This is achieved through development of Nuclear Plant Interface Requirements (NPLRs) for each nuclear unit that are based on plant-specific Nuclear Plant Licensing Requirements and Bulk Electric System requirements that have been mutually agreed to by the Nuclear Plant Generator Operator and the applicable

Organization	Yes or No	Question 6 Comment
		Transmission Entities. The NPLRs are requirements included in the design basis of the nuclear plant and statutorily mandated for the operation of the plant, including nuclear power plant licensing requirements for 1) Off-site power supply to enable safe shutdown of the plant during an electric system or plant event; and 2) Avoiding preventable challenges to nuclear safety as a result of an electric system disturbance or transient condition is important. It is essential that this process be followed closely in attempting to apply new grid frequency and voltage requirements that are more extreme than those currently addressed in each plant's licensing and design basis. It is fundamental that the safety of nuclear power plants take precedence. **While the Transmission Owner can address preventable challenges, equipment failures and weather-induced transients can still occur. Grid stability would be compromised if one type of generating facility is allowed to trip for any excursion in voltage or frequency.** 5) R3 states "each" non-protection system equipment limitation where R1 and R2 say "a". Is there a reason for this difference? The feasibility of fully analyzing an existing plant to determine this is extremely questionable. There is no doubt that the cost would be horrendous. **The SDT has revised Requirements R1 and R2 to use the word "each". The SDT disagrees that the analysis is onerous. Requirements R1 and R2 apply only to the generator protection system. If the settings for this system are such that the generator would be tripped for conditions inside the No Trip Zone of Attachments 1 and 2, then the Generator Owner can either modify the settings or document the limitation that prevents modifying the settings (e.g. LP blade resonance during low frequency operation).** 6) We suggest modifying Footnote 2 - add "being built to a completed certified standard design" to this list. If the industry is going to move forward in utilizing standard plant designs to reduce cost and expedite getting plants built, the certified design must be acknowledged. If the equipment to meet this standard can be obtained, which is doubtful, the only way to reasonably attempt to have a design that meets it is to start with these requirements as design criteria at the very beginning. To place requirements such as this on completed standard designs would destroy the use of that concept. **Footnote 2 already includes generators "under construction". This would include those "being built to a completed certified standard design". The SDT has extended the Effective Date of Requirement R5 (the performance requirement for new facilities) from three years to six years past the date of approval in order to accommodate the need to develop new designs.** 7) The approval of this standard as written will have extreme effects on the construction and operation of generating units which could also affect safety and availability. It would greatly increase the cost and schedule for building generation units and impose a huge cost on existing ones. We believe those developing this reliability standard should be sensitive to such concerns and give them consideration. Has this been done? Is it fully documented and available for review by the industry impacted by the proposal? **Wind facilities are already required to perform to similar criteria through FERC Order 661A. European utilities also have ride through requirements in place. The SDT realizes that this will impact the design of future generating facilities and increase their cost. The SDT is also charged with complying**

Organization	Yes or No	Question 6 Comment
		with FERC Order 693 and the recommendations in the 2003 Black Out Report.
Response: Thank you for your comments. See specific responses above.		
PacifiCorp	Yes	In addition to the feedback noted above, the NO votes submitted by PacifiCorp are accompanied with the following comments: (1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. (2) PacifiCorp maintains several additional concerns about complying with the standard as drafted: o R1.1.5 - PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec. There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function.** o R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **The standard refers to transmission system Zone 1 faults.** o R3 - This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate**

Organization	Yes or No	Question 6 Comment
		capacity greater than 10%. o R6 - The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. **Requirement R6 contained an exception for impending or actual loss of synchronism. The SDT has revised the wording to include any condition that will damage the equipment, such as the torque swings cited.** (3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered:2.1 When operating under normal system operating conditons within 95% and 105% of rated generator terminal voltage and during the transmission system conditions define in PRC-024 Attachment 2, with the following clarifications for PRC-024 Attachment 2 are provided:2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time.2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to in PRC-024 Attachment 2.2.1.3 Tripping a generator via If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the is acceptable in the "no trip zone" in PRC-024 Attachment 2 is acceptable.2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable than setting relays to trip the generator even if operating within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable. **The wording in Requirement R2 has been revised to clarify intent.** (4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.**

Organization	Yes or No	Question 6 Comment
		(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. **Requirement R4 has been removed.** (6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they would be non-compliant. The SDT should add this critical clarification to the VSLs. **The SDT agrees and has revised the VSL's for Requirements R1 and R2 accordingly.** (7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **The SDT believes specifying dynamic reactive power requirements is beyond the scope of the SAR for this project.** (8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT has been charged to make this standard technology neutral. If PacifiCorp feels there are significant differences in how different technologies can perform, please provide detailed information to the SDT.**
Response: Thank you for your comments. See specific responses above.		
Tri-State Generation and Transmission, Inc.	Yes	The proposed WECC-0065 does not comply with the generator overfrequency curve.

Organization	Yes or No	Question 6 Comment
Response: Thank you for your comments. The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.		
Manitoba Hydro	Yes	Please provide justification for the curves provided in Attachments 1 and 2.
Response: Thank you for your comments.		
Exelon	Yes	Applicability section and Requirements R.1 and R.2Most nuclear power plants will not meet the requirements for frequency due to NRC required protection for Reactor Coolant Pumps and Reactor Protection System Motor Generator sets. In addition, most nuclear power plants will not meet the voltage requirements due to NRC required degraded voltage protection. Although a provision for exemption is permitted in R.3, Exelon requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. **The SDT believes that the existence of Requirement R3 removes any conflicting dual regulation with regard to nuclear plants.** Requirement R.3 second bulletThe equipment limitation expiration should not be dependent on a capacity increase of the generating unit. An equipment limitation may be the result of NRC regulations and not the generating unit capacity. **The SDT agrees that NRC nuclear safety requirements form a valid technical limitation. Requirement R3 has been revised so that the allowance for an equipment limitation expires only if the equipment causing the limitation is being replaced or upgraded such that there is a 10% increase in generator nameplate capacity.**
Response: Thank you for your comments. See specific responses above.		
Independent Electricity System Operator	Yes	1. R3: Please clarify the meaning of the expression "non-protection system equipment". Does it mean "a limitation imposed by equipment other than the protection system"? **SDT: Yes.** Or does it refer to generating units that are NOT equipped with frequency/voltage protective relays? **SDT: No.** In the latter case, how would the GO determine that the units that are not so equipped are unable to meet the criteria in Requirement R1 or R2? In our view, units that are unable to meet these criteria are those that are equipped with frequency/voltage protective relays and whose trip settings do not meet the criteria specified in R1 and R2 for specific technical reasons that are communicated to the Transmission Planners. For units that are NOT equipped with such protective relays, the suggestion that any of them may be unable to meet the criteria in R1 and R2 could be those which in the past have tripped before the thresholds. However, unless a unit repeatedly trips under like circumstances, isolated incidences do not provide sufficient evidence to arrive at a conclusive determination. And for those units that are NOT equipped with the protective relays and have never tripped before the thresholds, there is no telling whether or not they can meet the criteria. For the above reasons, we suggest the SDT to revise the R3 to convey the requirement that the GOs shall provide the technical reasons for not meeting the R1 and R2 criteria only for those units that ARE equipped with the

Organization	Yes or No	Question 6 Comment
		protective relays and ARE set at different thresholds. **If a unit does not have voltage or frequency protective relays, then by default it will not be tripped by such relays during an excursion and the GO is in compliance.** 2. As indicated in our comments under Q3, we think R4 is a sub-requirement or part of R3 since R4 mandates the GO to respond to the listed entities within 30 days of receiving a request, and that in the requirement there is no mention of "what" the response should entail. The "what is stipulated in R3. **The SDT agrees and has removed Requirement R4.** 3. R7: We assess that this requirement duplicates with what we interpret as the intent of a good part of R3, i.e., to provide the listed entities with the settings of the frequency/voltage protective relays. Regardless of whether or not a GO is able to meet R1 and R2, it should be obligated to provide the generator protection trip settings to these other entities for modeling purpose (consistent with our comments under Q3). If a GO sets the protective relays at values that do not meet the R1 and R2 criteria, then it should be obligated to provide the technical limitations that form the basis of the deviation. This requirement thus should come after R1 and R2, and replaces the as written R3 for reasons that we mention in our comments in (1), above. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		
Wisconsin Electric	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system

Organization	Yes or No	Question 6 Comment
		faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent.** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded.** 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing and proposed wording and has not made a change.**
Response: Thank you for your comments. See specific responses above.		
We Energies	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel**

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		that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded. 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing and proposed wording and has not made a change.**
Response: Thank you for your comments. See specific responses above.		
We Energies	Yes	1. The Applicability of this standard should be specifically stated to be limited to generators connected at 100kv or above, as in the Registry Criteria. **The Applicability is to Generator Owners. By default, the applicable equipment defers to the Registry Criteria which includes only equipment connected at 100 kV or above plus black start facilities regardless of connection voltage.** 2. The Effective Dates should be increased by one year. 5.1 should be two years, 5.2 should be three years, and 5.3 should be four years. This change would more appropriate for the significant analysis needed to meet these requirements. **The SDT has increased the Effective Date for Requirement 5 (the performance requirement) from three years to six years past the date of approval. The SDT feels the effective date for the remaining Requirements can remain the same.** 3. Requirement R1.5 should be deleted. The rate of change of frequency is not a parameter that is widely available in generator protection schemes on existing units. Requirements 1.1 through 1.4 are sufficient to prevent undesirable operation. **R1.5 allows tripping if the frequency rate of change exceeds 2.5 Hz/sec. It does not require installation of equipment that has this capability. Allowing tripping for this rate of change within the No Trip Zone is not allowed in Requirement 1, parts 1.1 through 1.4.** 4. Requirement R2.1.1 needs more clarity. Generator voltage relaying is not generally set to trip for system faults. Also, R2.1.2 is unclear as to what "less stringent" means; the reference to the Transmission Planner "settings" should perhaps be changed to "requirements". **Requirement R2 has be revised to clarify intent.** 5. In R3 and in R7, the allowable times should be 90 days rather than 30 days. This is due to the effort required to perform an adequate investigation. The "Lower" Violation Risk Factors for these two requirements would seem to be consistent with this. In R7, change "written request" to "request". **The SDT does not feel that 30 days is unreasonable to provide documentation of a limitation (R3) or to provide trip settings information (R7). The SDT is leaving the word "written" to differentiate between a verbal request that is not normally recorded.** 6. In R2 (second sentence), replace "shall set its protective relaying not to trip ... " with, "shall set its protective relaying to avoid tripping ..." **The SDT believes there is not a substantial difference between the existing**

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		and proposed wording and has not made a change.
Response: Thank you for your comments. See specific responses above.		
Great River Energy	Yes	It is not clear that this standard is needed. While attempting to eliminate unit tripping from frequency and voltage excursions is a laudable goal, it may not be practical to eliminate all unit tripping for these reasons. Furthermore, it creates the situation where literally every unit trip could become subject to a compliance violation investigation. Before this standard is finalized, NERC needs to assess how it is going to manage compliance enforcement with it.The posting of the ballot is confusing. The red-line documents are, in fact, clean (i.e. there are no red-lines) documents that do not line up with the "clean" documents. Thus, it is not clear what is being voted on. For example, the "clean" document shows that there are five parts with Requirement R1. The "redline to last posted" document has four subrequirements under the main requirement R1. **The SDT apologizes that a true redline document was not posted. The document being balloted was the second draft of version 1 of the standard.** The basis for the values established in parts 1.1 through 1.5 does not appear to be well documented. We understand from reviewing the documentation that the SDT appears to have reviewed a number of actual events. Documentation of this review would allow us to better understand the drivers for these values. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** The values in parts 1.1 through parts 1.5 do not appear to be well coordinated with UFLS. For instance, UFLS will actuate at 59.3 Hz per the UFLS standard while many generators could trip at 59.4 Hz that could cause a cascade of units tripping from degrading frequency. Hopefully, the UFLS actuation would prevent a downward spiral of frequency but that coordination is not clear at this point. **Requirement R1, Parts 1.1 through 1.5 have been removed. The information from Part 1.5 has been incorporated into the body of Requirement R1. The curves in Attachment 1 were developed in coordination with the UFLS SDT. These curves match the Generator Tripping expectation in PRC-006-2 Attachment 1.** Requirement R7 is partially redundant with Requirement R3. R3 already requires documentation and communication of equipment limitations. Thus, R7 creates the potential of double jeopardy. **The SDT agrees that there was potential confusion and has revised the wording in Requirement R7 to address your concern.**
Response: Thank you for your comments. See specific responses above.		

Organization	Yes or No	Question 6 Comment
Duke Energy	Yes	During the drafting process, quite a bit of feedback was provided to the SDT about concerns if this became a performance standard and the response was that this is only a relay setting criteria. However, plant performance aspects have been incorporated, using the allowed operating bands developed as a setting coordination. The concerns include: o Existing nuclear plant settings are inside the published no-trip bands o How quickly plant secondary system motors will decelerate with voltage below ANSI MG-1 criteria. o Why is a voltage ride-thru criteria beyond existing second zone or breaker failure/critical clearing time design approaches needed?For frequency, the ride-thru criteria should be long enough in duration for UFLS to perform its function. Also, the lowest frequency allowed for unit operation must accommodate the turbine blade resonance low frequency requirement for large steam plants (57.5 to 58.5 Hz, depending on the turbine OEM). Similar restrictions may also apply for the high frequency requirement.For voltage, the ride-thru criteria should be long enough in duration for second zone or breaker failure protection critical clearing time. Voltage recovery to 0.9 PU following critical clearing time is necessary to ensure electrically powered equipment will perform correctly.Nuclear power plant interface requirements are addressed in NERC Reliability Standard NUC-001-2. PRC-024-1 should allow nuclear power plant interface requirements to be managed under NUC-001-2.(See PowerPoint and AREVA white paper provided to the SDT).
Response: Thank you for your comments. There is a performance requirement only for facilities that are designed and built after this standard is approved and becomes effective. Existing plants, nuclear or otherwise, that can document technical limitations to operating in portions of the No Trip Zones defined in Attachments 1 and 2 are allowed by Requirement R3 to trip to protect the equipment as long as the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner are notified so they can correctly model the generator's performance during an excursion. Nuclear plants must comply with many NERC Standards beyond NUC-001-2.		
US Army Corps of Engineers	Yes	-R2.1.1 - 'not to exceed 9 cycles' this wording is confusing and needs to be clarified.-Suggest that Requirement R4 be rewritten to add specificity as to what must be included in the required written response, similar to the specificity and clarity includ
Response: Thank you for your comments. This part has been revised to clarify intent.		
ISO New England Inc.	Yes	Comments are provided by ISO-NE on the following requirements: R2.1. This requirement specifies when operating (within the band specified) of rated terminal voltage (VT) and during the transmission system operating conditions defined in PRC-024 Attachment 2 .... ISO-NE maintains that the band applies to the voltage as shown in Attachment 2 on the Y axis as the "Point of Interconnection-Voltage (PU). R2.1 should refer to the voltage at the point of interconnection and not the generator terminal voltage. The band shown as .95 p.u to 1.05 p.u. should be widened to at least .90 p.u. to 1.05 p.u. as suggested in our comments on Question 1 above R2.1.1 infers that the standard is to base the voltage relay settings on actual fault clearing times. The

Organization	Yes or No	Question 6 Comment
		standard should be 9 cycles. As the system changes, clearing times may change and then problems with an existing generator who has set its relays to the actual clearing times may be an issue. Changing this requirement would also require a change in the curve shown in Attachment 2. If this comment is ignored, as an alternative ISO-NE suggests that R2.1.1 be modified to state, "For three-phase transmission system zone 1 faults with Normal Clearing, set voltage relays based on actual fault clearing times, plus margin, not to exceed 9 cycles." This is suggested to direct the setting of relays in a manner that will prevent a relay race that could trip the generator sooner than the actual fault clearing time. **The SDT does not believe there is a significant reliability gain to making all generators set relaying to account for 9-cycle clearing. If the voltage profile remains within the No Trip Zone, then the Generator Owner would be out of compliance if a generator trips due to operation of a voltage relay. The SDT expects that the GO will recognize this and provide some margin in the settings.** R2.1.3 appears to provide a way to get around the intent of the standard. If a generator cannot meet the requirements of the standard, they could put in an SPS to trip the generator and avoid meeting the intent of the standard. This has the potential to lead to a proliferation of SPSs. **In many cases an SPS will trip a generator for loss of certain transmission elements in order to prevent overloading the remaining elements. Overriding the operation of an SPS by not allowing it to trip generation could lead to grid instability and cascading outages. NERC Standard PRC-015 requires an SPS to meet NERC and RRO criteria, so GO's do not have carte blanche to install an SPS to avoid compliance with the PRC-024 requirements.** Notwithstanding the concern over R 2.1.3, R2.1.3 and R2.1.4 should be rewritten as follows: 2.1.3. If a Special Protection System (SPS) or Remedial Action Scheme (RAS) includes tripping a generator after fault initiation, then setting the SPS or RAS relays to trip the generator even if [voltage is] in the "no trip zone" in PRC-024 Attachment 2 is acceptable [provided that the voltages will not enter the trip zone for criteria faults that do not initiate the SPS or RAS].2.1.4. If clearing a system fault necessitates disconnecting a generator, then setting relays to trip the generator even if operating [voltage is]within the "no trip zone" specified in PRC-024 Attachment 2 is acceptable. **The SDT believes the suggested additional wording is not necessary.** R3 is a significant concern. In the event that a generator has a piece of equipment which prevents it from meeting the requirements of R1 and R2, such as a motor contactor which drops out on voltages in the "No Trip Zone", there is no requirement to correct the issue. Instead, the generator must only document the limitation. This completely undermines the intent of this standard. There is no point to setting undervoltage relays to meet the curve if other equipment is still going to trip the plant. **The SDT recognizes that contactor performance can be a factor in the ability of a generating facility to ride through a voltage excursion. We believe that requiring existing facilities to rebuild their entire auxiliary system to ride through events as severe as described by Attachment 2 (which are not common occurrences) would**

Organization	Yes or No	Question 6 Comment
		divert resources that could be better used elsewhere in improving grid reliability. Over time, as existing facilities are retired, the new facilities that are built will have to be designed to meet the performance requirement of this standard. R5 appears similar to R3 in that the generator is only required to document if it trips in the "No Trip Zone", rather than correct the issue. **This Requirement is intended to improve the modeling of generator performance by giving the Reliability Coordinator, Planning Coordinator, Transmission Operator, and Transmission Planner an estimate of how long a facility will remain connected following a voltage or frequency excursion defined by one of those four entities.** Exceptions in 6.1.1 and 6.2 should not be allowed. Each generating unit that is registered based on the NERC Registry Criteria as a single unit, or as part of a generating facility, should comply with PRC-024-2 without exception. In general, R6 and sub-requirements R6.1 through R6.7 introduce a number of conditions and exceptions for new units that are unnecessary and cumbersome to monitor. Some of them represent common sense conditions, such that if they were to occur, an auditor would be able to deem the entity to be in compliance since it is not posiible to comply with the letter of the requirement. However, there are many more cases that could be listed and you will never capture all possibilities here. Overall R6.1 through R6.7 should be deleted. As the system changes, the requirements will change. The machine should be properly designed upon installation to allow the necessary flexibility in the development of the transmission system over time. **The SDT realizes that these conditions and exceptions may not be all inclusive, but believes they cover the majority of real-world cases that would justify tripping. If the conditions and exceptions were eliminated, auditors would not have guidance to realize the intent that there are some justifiable reasons for tripping.**
Response: Thank you for your comments. See specific responses above.		
Luminant Energy	Yes	Luminant still believes that the standard should be directed to generator protective relaying only.
Response: Thank you for your comments. In order to comply with FERC Directives, a performance requirement was added to Draft 2.		
Ameren	Yes	1)Comments: Requirement R1.5 is unclear. Are the relays not allowed to trip regardless of frequency if the rate of change is less than 2.5 Hz/sec. If so, the existing generator relays don't have the capability to block for this condition. It would seem undesirable to block for this condition and risk damage to generation. **R1.5 *allows* a generator to trip within the No Trip Zone of Attachment 1 if the rate of change of frequency *exceeds* 2.5 Hz/sec.** 2)R2.1.3 needs to be more specific. With multiple outlet lines, generators may only be tripped for certain lines or breaker failure conditions. Generators would only be allowed to trip in the "no trip zone" for the specific

Organization	Yes or No	Question 6 Comment
		conditions of the SPS or RAS schemes? **The SDT believes the wording is clear as written. If an SPS or RAS detects a condition that requires tripping a generator, then that tripping is allowed.** 3)R6.2 why are smaller generators allowed to trip 10% of their units? Is this fair to large generators? **The SDT feels that allowing 10% of small generators to trip is fair because it is similar to a large unit experiencing a run back following an event. Runbacks do not result in a compliance violation.** 4)Do all the requirements of PRC-024-1 apply to all the auxiliary systems, or just the generating unit protection systems? This needs to be made clear for compliance. If applying to all auxiliary systems, guidance will need to be provided on how to meet these standards. **Requirements R1 and R2 apply only to the generator protection system as stated in the Footnote 1. Requirement 6 applies to the performance of the entire facility, not just the generator protection system.** 5)For R2 and R6, if clearing a transmission line outlet end of line fault with zone-2 timing exceeds the requirements of Attachment #2, which should be designed for. Does transmission line relays need to be designed to provide performance of Attachment #2 for newly installed facilities? **This standard does not set requirements for the protection of the transmission system. If the voltage profile at a specific generating site exceeds the requirements of Attachment #2, then the generator(s) at that site would not be out of compliance if they tripped.**
Response: Thank you for your comments. See specific responses above.		
American Electric Power	Yes	The second point under R3 causes the limitation to expire with rating increases. Is a 10 percent or more rating increase a realistic scenario and common enough to justify attention? 10 percent seems arbitrary and this provision could pose a hindrance to rating increases that may supply other reliability benefits. It may be advisable to remove this point. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** We believe that R2.1.4 must not allow relay settings to trip a generator within the no-trip zone for other system events that would not disconnect the generator. **The SDT agrees and has added wording to clarify that this tripping is only acceptable if the generator must be tripped in order to clear the fault.** The phrase "generating plant or Facility" is used in R2, R3, R5 and R6, but not R1. **The SDT agrees and has changed the wording in Requirement R1 accordingly.**
Response: Thank you for your comments. See specific responses above.		
Texas Reliability Entity	Yes	In the ERCOT Interconnection (ERCOT) there are well-established generator under-frequency relay settings

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		(ERCOT Nodal Operating Guides 2.6.2) that are more stringent than those proposed in this standard. ERCOT also has existing low/high-voltage ride-through requirements (ERCOT Nodal Operating Guides 2.9(2)) that are less stringent than those proposed in the standard. We would prefer to include the existing ERCOT parameters in this standard to apply within the ERCOT Region, rather than having different ERCOT and NERC requirements. We suggest that the drafting team consider adding ERCOT-specific parameters in Attachments 1 and 2, matching the existing ERCOT Nodal Operating Guide requirements, in addition to the stated parameters for the other interconnections.
Response: Thank you for your comments. The SDT has added ERCOT-specific curves to Attachment 1.		
RFC	Yes	For R3, add the word “generating” in front of the word “Facility” to be consistent with other requirements. **The SDT agrees and has changed the wording accordingly.** The followoing are reccomendations related to the Violation Severity Levels:1. VSL for R1 - a. The VSL should start off with the following language to be consistent with the language within the requirement: “The Generator Owner that has frequency protective relaying activated to trip its new or existing generating unit failed to...” **The SDT agrees and has changed the wording accordingly.** b. Since there are a number of Parts associated with R1, the SDT may want to consider gradating the VSL rather than making it Binary. **The sub parts of R1 have been removed. The VSL will remain binary.** 2. VSLs for R2 - a. The VSL should start off with the following language to be consistent with the language within the requirement: “Generator Owner that has voltage protective relaying activated to trip its new or existing unit or generating plant or Facility failed to...”b. There is no reference to any of the Part numbers for R2. Suggest adding references to the Parts to the VSL or since there are a number of Parts associated with R2, the SDT may want to consider gradating the VSL rather than making it Binary. **The sub parts of Requirement R2 are conditions that allow tripping within the No Trip Zone. They do not create violation conditions. The VSL will remain binary.** 3. VSLs for R3a. Suggest not using the language “...prevents compliance with Requirement R1 or R2...” since it is not consistent with the language of the requirement. Suggest stating: “... prevents the Generator Owner from meeting the criteria in Requirement R1 or R2...” **The SDT agrees and has changed the wording accordingly.** 4. VSLs for R5a. Fix the typo in the “Severe” VSL. Change “R55” to “R5”5. **The SDT agrees and has changed the wording accordingly.** VSLs for R6a. The first VSL under the “Severe” suggest referencing “Attachment 1” rather than “Requirement 6.” This will make it consistent with the other “Severe” VSL. **The SDT agrees and has changed the**

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		wording accordingly. b. Suggest adding another VSL which references the GO not following the conditions and exceptions in Parts 6.1 through 6.7. As written, there is currently no reference to the Parts. **The sub parts of Requirement R6 are conditions that allow tripping within the No Trip Zone. They do not create violation conditions. The VSL will remain binary.**
Response: Thank you for your comments. See specific responses above.		
Consolidated Edison Co. of NY, Inc.	Yes	Requirement R3. - Delete the word "expires" and replace it with the words "documentation should be renewed" **The SDT has changed the wording to clarify intent.** The underlying technical justification for this standard should be supported by a white paper similar to the document available at this link (AREVA PRC-24 White Paper Clean.doc): http://xa.yimg.com/kq/groups/28536519/188315025/name/AREVA%20PRC-24%20White%20Paper%20Clean.doc **The SAR that justified drafting of this revision to PRC-024 was approved by industry in 2007.** Requirement R3, bullet 1 allows for an exemption for existing plants subject to equipment failures until "the limitation [limiting equipment] is repaired or replaced." Similar temporary exemption language should be incorporated in R6 for new units that experience equipment failure-related limitations. **The exemption in Requirement R3 is intended for permanent conditions due to the design of existing equipment (e.g. steam turbine LP blade fatigue life at reduced operating frequencies). If a new plant experiences an equipment failure that would prevent it from riding through an excursion, the GO can request a waiver from the Reliability Coordinator, since the RC may need the generation for reliability reasons and elect to allow a unit to operate with its greater risk of tripping during an excursion** The drafting team may also wish to address a requirement for repair or replacement timeliness in both R3 and R6. **. The SDT believes that changes made for Requirement R3 will be part of a planned uprate project and the RC's ability to deny or rescind a waiver for Requirement R6 is incentive for the GO to make repairs expeditiously.**
Response: Thank you for your comments. See specific responses above.		
GE Energy	Yes	Clause 6.1.1 allows an exception from meeting the ride through requirements for voltage support equipment that is not in service. Often such equipment is installed solely for the purpose of acheiving ride through. It is not clear that there are any NERC standards requiring that this equipment be maintained to have a minimum

Organization	Yes or No	Question 6 Comment
		level of availability. As worded, this clause could create a means by which a GO could indefinitely avoid requirements, and subsequent penalties for non-compliance.
Response: Thank you for your comments. The SDT agrees and has removed the wording regarding voltage support equipment.		
PPL Electric Utilities	Yes	1. The term “continuous capacity rating” in the second bull-dot item of R3 should be replaced with “Normal Rating or Emergency Rating,” to eliminate ambiguity via use of NERC Glossary-defined terms. **The SDT has changed the wording to “nameplate rating”.** 2. The term “non-protection system” in R3 should be replaced with “non-Protection System,” to make it clear that achieving the criteria of R1 and R2 might be prevented by in some cases by OEM controls trip settings, thereby constituting a protection system function (acceptable) that does not involve the Protection System (would be unacceptable). **The SDT agrees the wording was less than optimal and has revised Requirement R3 to state, in part, “Each Generator Owner of an existing generating unit or generating plant or Facility shall document each equipment limitation (excluding generator frequency and voltage protective relay limitations)…”** 3. Paras. R5.1 and R5.2 suffer in terms of clarity from consisting of a single sentence that is over 80 words long, with not a single comma or semicolon to guide the reader. NERC standards should make use of normal technical-writing style and punctuation **The SDT agrees. Requirement R5, section 5.2 has been removed. Section 5.1 now states “An estimate of the time duration the existing unit or generating plant or generating Facility will remain connected (considering performance of the auxiliary systems as well as the generator) as a result of a frequency excursion and/or a voltage excursion defined by the voltage and/or frequency profile at the point of interconnection described by dynamic simulation provided by the Transmission Planner. If the Generator Owner expects the existing unit, generating plant or generating Facility will remain connected for longer than 10 minutes, then the estimate should indicate that the existing unit, generating plant or generating Facility is not expected to trip.”**
Response: Thank you for your comments. See specific responses above.		
American Transmission Company	Yes	Please give consideration to the following suggestions:1. In Requirements, R1, R2, & R3 - include a footnote for the references to “non-protection system equipment” that defines or gives a few examples of this equipment to add clarity. **The SDT believes the primary limitation will be steam turbine LP blade fatigue loss of life when operating at reduced frequencies. Generator Owners are well aware of this limitation.** 2. In Requirements, R3 - add the requirement that the GO provides the expected duration of the limitation, if it is known. **The SDT believes these would normally be permanent limitations. If the Reliability**

Organization	Yes or No	Question 6 Comment
		Coordinator, Planning Coordinator, Transmission Operator or Transmission Planner had reason to believe a limitation was not permanent, it could make an inquiry of the Generator Owner. 3. In Requirements, R5.2 - include a footnote or example of "25% estimated probability increments" to add clarity. **The SDT has removed the Requirement R5, section 5.2 (the requirement to provide 25% probability estimates).** 4. In References - include references that provide more technical justification and background for the voltage and frequency limits given in Attachment 1 and Attachment 2 **The WECC white paper cited in References provides justification for the curves in Attachment 2. The curves in Attachment 1 are identical to PRC-006 Attachment 1 Generator Tripping expectation curves and are set to provide a margin beyond the UFLS performance expectations.** .5. In Attachment 1 - add a "Return to between 59.5 Hz and 60.5 Hz frequency" text box to be consistent with the labeling in Attachment 2. **The SDT disagrees that this is necessary because with the addition of WECC-specific and Quebec-specific curves, adding another text box would add to information overload.** 6. In Attachment 1 - add the title "Curve Data Points" to the Frequency/Time table to be consistent with Attachment 2. **The SDT agrees and has changed the wording accordingly.** 7. In Attachment 2 - modify HVRT and LVRT tables (perhaps combine them into one more compact table) to be consistent with the table in Attachment 1 and fit on the same page. **The SDT agrees and has reformatted the tables for both Attachment 1 and Attachment 2.** 8. In Attachment 2, 5a - expand to "Power factor is 0.95 lagging (i.e. supplying reactive power to the system as measured at the generator terminal)" to be more definitive. **The SDT agrees and has changed the clarification to state: "Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals)".**
Response: Thank you for your comments. See specific responses above.		
Hydro-Quebec TransEnergie	Yes	The graph of voltage from the interconnexion of Quebec was reflected from the FERC order 661-A which is different from the graph from this standard. Please justify the source of the present standard.
Response: Thank you for your comments. The voltage profile in Attachment 2 was developed using the voltage profile from FERC Order 661A, the profile developed in WECC (see the WECC White Paper listed as a Reference in the Standard), and studies done in the SERC region.		
CenterPoint Energy	Yes	(a) CenterPoint Energy does not agree with limiting the applicability of Requirement 2 to just "voltage protective relaying". In effect, this would allow possible tripping of generation during off nominal voltage

Organization	Yes or No	Question 6 Comment
		excursions from several other types of relays, such as generator backup over-current and impedance. CenterPoint Energy recommends that this standard be applicable to any generator Protection System relays that operate on voltage and / or current. **The SDT agrees and has revised Footnote 1 to state, in part, "…frequency or voltage protective relaying (including but not limited to frequency and voltage protective functions for discrete relays, volts per hertz relays evaluated at nominal frequency, impedance relays, voltage controlled overcurrent relays, multi-function protective devices or protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs)…"** (b) In Requirement 2.1.1, the fault clearing time should be established at a fixed 9 cycles, instead of site-specific, actual clearing times. R2.1.1 should be written as: "For three-phase transmission zone 1 faults, set generator Protection System relays based on a fault clearing time of 9 cycles". **The SDT disagrees that Generator Owners should be prevented from using site-specific clearing times and voltage profiles when they can be provided by the Transmission Planner.** (c) Requirement 2.1.2 provides for location-specific criteria that are unnecessary and could have unintended consequences, as such criteria can change over time with additions and modifications of the bulk electric system. CenterPoint Energy believes NERC reliability standards should not include fill-in-the-blank, location-specific criteria and recommends R2.1.2 be deleted. **The SDT disagrees that Generator Owners should be prevented from using site-specific clearing times and voltage profiles when they can be provided by the Transmission Planner.**
Response: Thank you for your comments. See specific responses above.		
GenOn Energy	Yes	A strong disapproval of the R3 equipment limitation expiration with a generating unit rating increase of 10%. The expiration is unnecessary and is based upon an arbitrary criterion that may be totally unrelated to basis for the limitation. **The SDT has revised Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.** A backwards approach has been taken with the application of Attachment 2, which represents very poor performance of the transmission system for voltage recovery after a fault. This standard will have the affect of permanently defining this as acceptable transmission performance, which should not be the case. This is inequitable since it imposes the lowest common denominator of one segment of the industry and unilaterally transfers the responsibility for that performance upon another seqment (every generating unit on the continent). **The voltage profile in Attachment 2 was developed using the voltage profile from FERC Order 661A, the profile developed in WECC (see the WECC White Paper listed as a Reference in the Standard), and studies done in the SERC region. It does not represent the lowest common**

Organization	Yes or No	Question 6 Comment
		denominator. The Generator Verification team has developed extensive requirement for Generator Owners to provide accurate model data for system studies, but Generator Owners get no benefits in return for their effort and expense. **The SDT believes the Generator Owners get the benefit of a more reliable transmission system.** Rather than imposing Attachment 2 on Generator Owners, the more correct way is to require Planning Coordinators, Transmission Operators or Transmission Planners to provide planning study results and voltage recovery profile at the generator terminals (this is where the protection and controls are applied). This will enable Generator Owners correctly apply protection settings as appropriate. Another option is to drive performance improvements on the Transmission system. Attachment 2 should be set a much higher standard of performance of the transmission system (median or higher), and require the Planning Coordinators, Transmission Operators or Transmission Planners to identify the locations where the higher standard is not attainable and provide the voltage recovery profile. **Setting performance requirements for Planning Coordinators, Transmission Operators, and Transmission Planners is beyond the scope of the SAR for this project. The SDT suggests the commenter submit a SAR if he feels this would improve grid reliability.**
Response: Thank you for your comments. See specific responses above.		
Arizona Public Service Company		The measurement M6 for the new plant is not clear. One does not know how long a time it would take to get a significant event. M6 should be written such that if a unit did not trip for a system event, it will be considered compliant.
Response: Thank you for your comments. The Measure requires evidence that any trips that a generating unit experienced did not occur during a frequency or voltage excursion that remained within the No Trip Zone boundaries of Attachments 1 and 2. If the generating plant did not trip during the audit period, the final sentence in the Measure allows an attestation that the generating unit did not trip to serve as evidence of compliance.		
Western Electricity Coordinating Council		For the WECC variance we would need a revised Attachment 1 that also shows the WECC No Trip Zone or an additional Attachment to illustrate the WECC variance No Trip Zone. WECC also requires modified language to R1 and the parts 1.1-1.5 to reflect the WECC variance. Requirements R5 and R6 will need to be modified to identify the appropriate Attachment for the WECC variance.
Response: Thank you for your comments. A WECC-specific pair of curves has been added to Attachment 1.		

Additional Comments submitted by PacifiCorp – Sandra Shaffer:

In addition to the feedback submitted via the NERC comment website, the NO votes submitted by PacifiCorp are accompanied with the following comments:

(1) Industry practice for generation protective relays is to use the terminal voltage of the generators, not the system voltage or point of interconnection. Generator Owners could provide generation responses and data as contemplated by the standard, but they should not be held responsible for the answers provided without the benefit of associated transmission planning groups. Generator Owners, under this framework, will rely completely on feedback from their associated transmission planning groups in order to provide responses. It concerns PacifiCorp that the draft standard does not address the need for transmission planners to provide the required transmission system response data to Generation Owners in order to make these assessments, or allow for the joint responsibility of transmission planner for the accuracy of the data as it concerns planning studies. **It is not practical to define the excursions at the generator terminals due to the differences in generator, step-up transformer, and system characteristics. Other voltage ride through standards (e.g. FERC Order 661A and various European standards) all define the voltage profile at the transmission level (where the event occurs).**

(2) PacifiCorp maintains several additional concerns about complying with the standard as drafted:

- R1.1.5 – PacifiCorp is not aware of relays used for generator protection that use frequency rate of change to calculate trip points. Generator protection relays use frequency set points and time at certain values, not rate of change of frequency to make tripping decisions. It may not be technically feasible to immediately comply with this sub-requirement of the standard as written. **There are several standard generator protection relays (e.g. GE's G-60, Schweitzer's 700G, and Beckwith's M-3425A) in addition to relays that are designed specifically for Aurora Scenario protection that incorporate a frequency rate of change function. R1.1.5 does not require tripping for a frequency rate of change over the stated value, but does allow that tripping even if the frequency magnitude is still within the No Trip Zone.**
- R2.1.1 - PacifiCorp requests clarification concerning what the SDT has considered a zone 1 fault. PacifiCorp acknowledges that transmission and distribution line relays have zone 1 and zone 2, but the Company does not believe that this is something typically used in the generator protection context. A zone 1 fault needs to be defined somewhere to the extent that it is not clarified in the standard already. **Part 2.1.1 states "… transmission system zone 1 faults…" The SDT believes this makes it clear that it does not involve the generator or distribution system.**
- R3 – This requirement was clear in the initial February 2009 draft of PRC-024-1, but the current draft does not clarify that the Generator Owner must upgrade the equipment that is causing a limitation. For example, if an entity upgrades its (synchronous) turbines to increase capacity by greater than 10%, but the voltage limitations still exist because they are related to the generator, which is not upgraded, the exemption would expire under the current language. The SDT should revisit this issue using the initial draft of PRC-024-1 as a guide. **The SDT has revised**

Requirement R3 to clarify that the limitation must be eliminated if the equipment causing the limitation is modified or upgraded resulting in an increase in nameplate capacity greater than 10%.

- R6 – The failure to include exemptions for new generating plants may have unintended consequences. Some voltage excursions have caused excessive torque on PacifiCorp-owned generators which has caused the controls to trip the units, rather than the relays themselves. If an entity constructs a new plant and cannot document any exemptions due to equipment limitations, such entity may experience future compliance and operational issues. The SDT should revisit this in light of further consideration of potential unintended consequences. **Tripping generating units is allowed to protect the equipment from damage. In the example cited, it would be considered an impending loss of synchronism.**

(3) PacifiCorp has concerns that certain references to Attachment 2 in Requirement R2 need to be clarified. Attachment 2 references the generator point of interconnection not the terminal voltage; therefore, clarifications to the proposed language are necessary. As such, the following recommended revisions to Requirement R2 are offered:

2.1 When operating under normal system operating conditions within 95% and 105% of rated generator terminal voltage ~~and during the transmission system conditions define in PRC-024 Attachment 2, with~~ the following clarifications for PRC-024 Attachment 2 are provided:

2.1.1 For three-phase transmission system zone 1 faults with Normal Clearing, ~~set voltage relays~~ transmission system faults should be cleared based on actual fault clearing times, not to exceed 9 cycles. Voltage relays should be set to not trip prior to transmission system fault clearing time.

2.1.2 If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent ~~voltage relay settings~~ system protection settings than those on PRC-024 Attachment 2, set voltage relays either to the less stringent Transmission Planner's settings or the setting applicable to ~~in~~ PRC-024 Attachment 2.

2.1.3 Tripping a generator via ~~If~~ a Special Protection System (SPS) or Remedial Action Scheme (RAS) ~~includes tripping a generator after fault initiation, then setting the SPS or RAS relay to trip the generator even if in the~~ is acceptable in the "no trip zone" in PRC-024 Attachment 2 ~~is acceptable~~.

2.1.4 If clearing a system fault necessitates disconnecting a generator, this action is acceptable ~~than setting relays to trip the generator even if operating~~ within the "no trip zone" specified in PRC-024 Attachment 2 ~~is acceptable~~.

The wording in Requirement R2 has been revised to clarify intent. It now states: "Each Generator Owner that has generator voltage protective relaying **Error! Bookmark not defined.** **activated to trip its new or existing unit or generating plant or generating Facility shall set its protective relaying not to trip as a result of a voltage excursion**

(at the point of interconnection[3]) caused by an event on the transmission system external to the plant per the following operating conditions and relay settings unless the Generator Owner has documented and communicated each non-protection system equipment limitation in accordance with Requirement R3 for an existing unit or generating plant or generating Facility.

2.1 When operating within 95% to 105% of rated generator terminal voltage and during the transmission system operating conditions defined in PRC-024 Attachment 2, with the following clarifications:

2.1.1 **If a Transmission Planner's study (based on the location specific voltage recovery characteristics) recommends less stringent voltage relay settings than those in PRC-024 Attachment 2, set voltage relays either to the Transmission Planner's settings or the settings in PRC-024 Attachment 2.**

2.1.2 Tripping a generator via a Special Protection System (SPS) or Remedial Action Scheme (RAS) is acceptable in the "no trip zone" of PRC-024 Attachment 2.

2.1.3 **If clearing a system fault necessitates disconnecting a generator, this action is acceptable within the "no trip zone" specified in PRC-024 Attachment 2."**

(4) As drafted, Requirement R1 of proposed PRC-024-1 conflicts with WECC's Off-Nominal Frequency Load Shedding Plan ("WECC Coordinated Plan"), and could potentially result in negative reliability impacts if enforced in the Western Interconnection. A WECC Regional Variance that includes the WECC Generator underfrequency and overfrequency operation requirements, as identified in the WECC Off-Nominal Load Shedding Plan, must be added to the proposed standard. WECC has developed, implemented, and verified the effectiveness of the WECC Coordinated Plan and any deviations from the requirements of the plan may negatively impact its effectiveness. **The SDT has added a WECC-specific curve to Attachment 1 to address WECC's UFLS program.**

(5) PacifiCorp believes that the SDT should rewrite Requirement R4 to add specificity as to what must be included in a written response to a submission concerning an equipment limitation, similar to the specificity and clarity included in MOD-026, Requirement R3. **The SDT agrees and has removed Requirement R4.**

(6) PacifiCorp offers one comment on the Violation Severity Limits ("VSLs") proposed for Requirements R1 and R2 of PRC-024-1, which require that frequency protective relaying (R1) and voltage protective relaying (R2) be set so that they do not trip within the criteria listed in the respective requirements "unless the Generator Owner has documented and communicated a non-protection system limitation in accordance with Requirement R3." However, the language of the binary Severe VSL for Requirements R1 and R2 only identifies the failure to set protective relaying, without recognizing the exception granted for documenting and communicating a non-protective system limitation. As written, the applicable entity could be compliant with the language of Requirements R1 and R2, but based on the language of the VSLs, they

[3] For the purposes of this standard, point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.

would be non-compliant. The SDT should add this critical clarification to the VSLs. **The VSL's have been revised to address this issue.**

(7) PacifiCorp has a concern that the PRC-024 voltage ride-through requirements identified in Attachment 2 are wholly independent of dynamic reactive power requirements for generators. As an analogy, some European generator interconnection standards and requirements link these two variable. PacifiCorp understands that PRC-024-1 is a generator protection standard; however, the SDT should address the manner in which generator dynamic reactive requirements impact PRC-024-1 Attachment 2. **The SDT believes that creating dynamic reactive power requirements is beyond the scope of the SAR that was created for this project.**

(8) Many European generator interconnection standards and requirements include different voltage ride-through requirements for synchronous and non-synchronous generation. PacifiCorp is concerned that the SDT has inappropriately developed a "one-size fits all" standard applicable to all generation platforms. PacifiCorp recommends that, based on the significant differences between existing and emerging generation platforms, separate voltage ride-through standards be developed for synchronous and non-synchronous (i.e., wind and solar) generation platforms. Different sets of standards will more effectively address such differences in the various generation technologies. **The SDT has been charged to make this standard technology neutral. If PacifiCorp feels there are significant differences in how different technologies can perform, please provide detailed information to the SDT.**

Response: Thank you for your comments. See specific responses above.

END OF REPORT