NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Generator Verification Project 2007-09

The Generator Verification Drafting Team thanks all commenters who submitted comments on the proposed revisions to PRC-024-1. This standard was posted for a 30-day public comment period from December 12, 2012 through January 11, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 49 sets of comments, including comments from approximately 143 different people from approximately 98 companies representing all 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.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration: The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The majority of comments expressed agreement with the removal of loadability relays from PRC-024. One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed Requirement R4 from the standard~~s~~ because of ambiguous language and ~~dubious~~ limited reliability benefit.
- Revised the title of the standard to “Generator Frequency and Voltage Protective Relay Settings” and the Purpose Statement to “Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised “generating unit(s)” to “applicable generating unit(s)” to reflect that the standard only applies to units that meet the registry criteria.
- ~~Revised language of R1 to match that of R2.~~
- Added “regulatory or” language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised Requirement R2 so that the sentences were shorter and easier to read, and made conforming language changes in Requirement R1.
- Removed the last bullet from Requirement R3 and added ~~and~~ a new bullet referencing frequency impacts on turbines as follows: “Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance.”

- Revised Requirement R5 (now R4) to indicate that the trip settings to be provided are only those "associated with Requirements R1 and R2" and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).
- Made clarifying revisions to "Voltage Ride-Through Curve Clarifications" on the last page of the standard.
- Clarified Footnote 3 to: "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

Index to Questions, Comments, and Responses

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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	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.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent 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.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Brian Shanahan	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
2.	Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Group	X	X	X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA
2.	Robert Rhodes	Southwest Power Pool	SPP	NA
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Don Taylor	Westar Energy	SPP	1, 3, 5, 6
5.	Stephen McGie	City of Coffeyville	SPP	NA
6.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
7.	Mike Sheriff	Oklahoma Gas and Electric Company	SPP	1, 3, 5
8.	Harold Wyble	Kansas City Power and Light	SPP	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Charles Yeung	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Greg Campoli	NYISO	NPCC	2
2.	Bill Phillips	MISO	MRO	2
3.	Ben Li	IESO	NPCC	2
4.	Steve Myers	ERCOT	ERCOT	2

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. Matt Goldberg	ISONE	NPCC	2
6. Tom Bowe	PJM	RFC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	paul haase	seattle city light	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. pawel krupa	seattle city light	WECC	1
2. dana wheelock	seattle city light	WECC	3
3. hao li	seattle city light	WECC	4
4. mike haynes	seattle city light	WECC	5
5. dennis sismaet	seattle city light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade		RFC	5, 6
2. Randi Heise		MRO	5, 6
3. Mike Garton		NPCC	5, 6
4. Michael Crowley		SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Ian Grant		SERC	3
2. Marjorie Parsons		SERC	6
3. David Thompson		SERC	5
4. DeWayne Scott		SERC	1
5. Tom Vandervort		SERC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Greg Rowland	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils	Duke Energy	RFC	1
2. Lee Schuster	Duke Energy	FRCC	3
3. Dale Goodwine	Duke Energy	SERC	5
4. Greg Cecil	Duke Energy	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection

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

1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	TOM BREENE	WPS	MRO	3, 4, 5, 6
3.	JODI JENSON	WAPA	MRO	1, 6
4.	KEN GOLDSMITH	ALTW	MRO	4
5.	ALICE IRELAND	XCEL/NSP	MRO	1, 3, 5, 6
6.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
7.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
8.	JOE DEPOOTER	MGE	MRO	3, 4, 5, 6
9.	SCOTT NICKELS	RPU	MRO	4
10.	TERRY HARBOUR	MEC	MRO	1, 3, 5, 6
11.	MARIE KNOX	MISO	MRO	2
12.	LEE KITTELSON	OTP	MRO	1, 3, 5
13.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
14.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
15.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
16.	DAN INMAN	MPC	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL Energy Plus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

				1	2	3	4	5	6	7	8	9	10
10.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

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
1.	Stephen Hitchens	Technical Operations	WECC	1
2.	Rebecca Berdahl	Policy Development & Analysis	WECC	3
3.	James Burns	Technical Operations	WECC	1
4.	Deanna Phillips	FERC Compliance	WECC	1, 3, 5, 6

No.	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
2.	John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
4.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
5.	John Shaver	Southwest Transmission Cooperative	WECC	1
6.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
7.	Tom Alban	Buckeye Power	RFC	3, 4
8.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5

No.	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

No.	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Janet Smith	Arizona Public Service Company	X		X	X	X	X	X			
14.	Individual	ryan millard	pacificorp	X		X		X	X				
15.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
16.	Individual	Bill Shultz	Southern Company	X		X		X	X				
17.	Individual	Ken Gardner	Alberta Electric System Operator		X								
18.	Individual	John Bee	Exelon Corporation and its affiliates	X		X	X	X	X				
19.	Individual	Jim Keller	We Energies			X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Patrick Brown	Essential Power, LLC					X					
21.	Individual	Louis C. Guidry	Cleco	X		X		X	X				
22.	Individual	Michelle DAntuono	Ingleside Cogeneration LP					X					
23.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
24.	Individual	David Jendras	Ameren	X		X		X	X				
25.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
26.	Individual	Jonathan	Appelbaum	X									
27.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
28.	Individual	Anthony Jablonski	ReliabilityFirst										X
29.	Individual	Michelle Clements	Wolverine Power Supply Cooperative, Inc.	X									
30.	Individual	Kathleen Goodman	ISO New England Inc.		X								
31.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									
32.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
33.	Individual	Thad Ness	American Electric Power	X		X		X	X				
34.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
35.	Individual	Mike Hirst	Cogentrix Energy Power Management, LLC					X					
36.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X		X	X				
37.	Individual	Scott Kinney	Avista	X									
38.	Individual	Mike Hendrix	Idaho Power Company	X									
39.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					
40.	Individual	Kenneth A Goldsmith	Alliant Energy				X						
41.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
42.	Individual	Michael Falvo	Independent Electricity System Operator		X	X	X	X					
43.	Individual	Joylyn Faust	Consumers Energy Company										
44.	Individual	Michael Goggin	American Wind Energy Association								X		
45.	Individual	Brad Harris	CenterPoint Energy	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
46.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
47.	Individual	Alice IReland	Xcel Energy	X		X		X	X				
48.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
49.	Individual	Russell Noble	Cowlitz PUD			X	X	X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Agree	Supporting Comments of "Entity Name"
Brazos Electric Power Cooperative, Inc.	Agree	ACES Power Marketing
US Army Corps of Engineers	Agree	MRO NSRF
Alliant Energy	Agree	MRO NSRF

1. **The GVSDT has removed Requirement R5 from the standard. The standard drafting team believes that Requirement R4 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to design, build, operate and maintain synchronous generating facilities that could ride through any of the defined excursions without fail would not justify the resulting incremental gain in grid reliability. Do you agree with this revision? If not, please explain in the comment area below.**

Summary Consideration: The vast majority of stakeholders agreed with the removal of R5 from the standard. Several stakeholders suggested that there were issues with R4. These commenters pointed out that the requirement was ambiguous and provided no discernible reliability benefit while subjecting entities to potential compliance violations for making optimistic estimations. Stakeholders believe that the use of language such as "sound engineering judgment" is subject to interpretation and vague. Based on these comments, the GVSDT removed R4 from the standard. PRC-024-1 is now a relay setting standard.

Minority issue: Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard. The proposed draft of PRC-024 does not accomplish this. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection Agreements and not NERC Standards.

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	No	Recommend that the R4 be enhanced to give more detail on how to satisfy this requirement. As significant as R4 is, the Generator Owners need more guidance than what is currently stated.
Response: The GVSDT thanks you for your comment. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		

Organization	Yes or No	Question 1 Comment
PPL Corporation NERC Registered Affiliates	No	Although PPL Companies agree with the removal of R5, PPL is still concerned with the following criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis we could make regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit in the fleet, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance. For R4 to reach this goal we believe that PRC-024 Measure 4 should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable measure for R4.
Response: The GVSDT thanks you for your comment. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		
Alberta Electric System Operator	No	The AESO disagrees with this requirement being removed from Draft 5 and

Organization	Yes or No	Question 1 Comment
		believes that new generating must be required to be designed, built and maintained in compliance with PRC-024-1 unless it is due to equipment failure and in such cases the owner of the generating unit must report failure to the ISO with a plan to address the failure.
Response: The GVSDT thanks you for your comment. While the GVSDT understands your concern, ~~the preponderance of industry comments has indicated that this standard will not pass with a plant performance requirement included~~the team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate. ~~.~~		
We Energies	No	The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable response.

Organization	Yes or No	Question 1 Comment
Essential Power, LLC	No	We agree with the removal of R5, but am still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, “Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered,” (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that “No concrete data on which to base judgments - assume tripping,” is an acceptable response.
Cogentrix Energy Power Management, LLC	No	The NAGF agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using, “experience, actual event histories, or sound engineering judgment,” to determine how long units will remain connected during disturbances. It is understood that detailed calculations are not required, but the word “sound” implies that the estimates are to have some reasonable degree of authority, and the needed information for such inputs is generally not available. An unwarrantedly optimistic forecast could be worse than no input at all; so, until and unless a really huge

Organization	Yes or No	Question 1 Comment
		disturbance is recorded, the only fact-based prognosis that could be made regarding the excursions in Atts. 1 and 2 of PRC-024 would be to say for every unit, "Tripping may occur whenever ANSI C84.1 emergency voltage variation boundaries (+/-10%) are exceeded, and whenever frequency fluctuations exceed the normal, minor magnitude typically encountered," (the latter statement applies particularly for gas turbines with dry low-NOx combustors). We believe that this represents sound engineering judgment, but a person with (perhaps unjustified) expectations of something more quantitative might not agree. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve compliance, and for PRC-024 to reach this goal R4 should be deleted or at least it should state that "No concrete data on which to base judgments - assume tripping," is an acceptable response.
Cowlitz PUD	No	Cowlitz agrees with the removal of R5, but is still concerned with the criteria stated in R4. R4 allows using "experience, actual event histories, or sound engineering judgment," to determine how long units will remain connected given a PC or TP excursion profile. It is understood that detailed calculations are not required, but the word "sound" implies that the estimates are to have some reasonable degree of authority. Again Cowlitz points out that engineering staff is not available for small entities and must be contracted. Since the Standard does not limit the PC and TP on the severity of the excursion profile that can be submitted to the GO for a time duration estimate, there is no possible way to prepare for a worst case scenario. The Standard does not allow for the GO to negotiate a more reasonable time frame to submit a response to the requesting entity, and as such places undue burden on the GO to solicit contractor/consultant services in a short time frame. Further, the statement "sound engineering judgment" is subjective and open to much question as to when compliance has been achieved. NERC requirements and their associated measures should leave all parties with one, clear concept of what it takes to achieve

Organization	Yes or No	Question 1 Comment
		compliance, and for PRC-024 to reach this goal R4 should be deleted, or at the very least allow for engineering judgment (without "sound") and limit the excursion profile to cover generators operating under the exception provisions of the Standard. Further, the Standard should allow the requestors to judge responses as adequate or not, and if not satisfied request further substantiating evidence that is reasonable.
Response: The GVSDT thanks you for your comments. Based on industry input the GVSDT has removed Requirement R4 from the standard. The standard drafting team believes that Requirement R3 meets the reliability objective of the directive in Paragraph 1787 of FERC Order 693. In addition, the SDT agrees with stakeholders who indicated that the additional resources that would be required to provide an estimate of the time duration the generating unit(s) will remain connected if the unit(s) was to experience a frequency or voltage excursion would not justify the resulting incremental gain in grid reliability.		
American Wind Energy Association	No	AWEA does not support this revision, but does not wish to hold up the standards development process for PRC-024. AWEA strongly supported keeping the standard as a generator performance standard, believing that the standard would result in improved electric reliability. AWEA also supports NERC taking the lead in setting national reliability standards, instead of the far less efficient outcome of individual regions advancing their own reliability standards. Under FERC Order 661A, the wind industry is currently subject to more stringent voltage and frequency ride-through standards than other generation types, and keeping PRC-024 as a generator performance standard would have helped to level the playing field in this regard.
Response: The GVSDT thanks you for your comment and support of this standard development process. The team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate.~~The preponderance of industry comments has indicated that this standard will not pass with a plant performance requirement included.~~ This proposed standard is consistent across technologies in that it does not impose voltage or frequency ride through requirements on any generators. The GVSDT points out that the requirements contained in FERC Order 661A are enforced through Generator Interconnection		

Organization	Yes or No	Question 1 Comment
Agreements and not NERC Standards.		
CenterPoint Energy	No	CenterPoint Energy previously expressed concern that the proposed standard does not impose any minimum frequency or voltage ride-through requirements for existing generating stations. With this proposed revision, the standard will not even impose any minimum requirements for new generating stations. Failure of a generating unit to ride-through at least some minimum threshold of frequency and voltage excursions places the reliability burden solely on transmission entities. This makes is difficult to compensate for the generator's failure to perform and, therefore, is problematic for BES reliability.
Response: The GVSDT thanks you for your comment and understands your concern. The team has decided that inclusion of a plant performance requirement in a relay setting standard is inappropriate.~~The preponderance of industry comments has indicated that this standard will not pass with a plant performance requirement included.~~		
ACES Standards Collaborators	Yes	Thank you for making this change.
Response: The GVSDT thanks you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP is firmly in agreement with the removal of the ride-through performance requirement (R5) from PRC-024-1. Although we understand the intent to guarantee generation availability for a set of voltage and frequency transients, the project team has correctly determined that the costs far outweigh the benefits. In our view, this is in keeping with the spirit of the Cost Effective Analysis Process, Paragraph 81, and other risk-based compliance initiatives that were initiated to maintain that careful balance.
Response: The GVSDT thanks you for your comment.		

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group	Yes	
IRC Standards Review Committee	Yes	
Dominion	Yes	
Duke Energy	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
Cleco	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	

Organization	Yes or No	Question 1 Comment
Tacoma Power	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
ISO New England Inc.	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Liberty Electric Power LLC	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Sacramento Municipal Utility District	Yes	
Avista	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery Company LLC	Yes	
Xcel Energy	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation

Organization	Yes or No	Question 1 Comment
		between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The standard has been modified to provide 30 days increments between VSL levels as requested.		

2. **Several stakeholders pointed out that a portion of the allowable high frequency trip curve for the Eastern, ERCOT, and Quebec Interconnections (Attachment 1) exceeded the off-nominal frequency limits in IEEE C50.13 and IEC 60034 that are used by equipment manufacturers to design generators. The drafting team revised the high frequency portion of the curve from zero to two seconds for the Eastern and ERCOT Interconnections to meet the IEEE and IEC standards. This leaves no margin between the high frequency allowance for UFLS designers in frequency overshoot for that amount of time, but the drafting team feels this is acceptable. Do you agree with this change? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: A large majority of stakeholders agreed with the change made to Attachment 1. Some stakeholders questioned the potential impact this change might make due to the elimination of the margin between the allowable UFLS overshoot and the generator overfrequency trip setpoints. The GVSDT pointed out that setting overfrequency tripping at this point would be allowed under the previous curve as a technically-based exemption under Requirement R3 and the change made removes a conflict with internationally-recognized technical standards.

Organization	Yes or No	Question 2 Comment
Southwest Power Pool Reliability Standards Development Group	No	Our concern is by eliminating the instantaneous high frequency overshoot margin that you could cause an unintended cascading event on the system. For example when you drop load it could cause an instantaneous unit trip, due to instantaneous high frequency on the unit, which would then cause an under frequency load trip. We would suggest that the drafting team let the regions investigate before approving this reduction in the margin for this time period and standard as a whole.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		

Organization	Yes or No	Question 2 Comment
IRC Standards Review Committee	No	We are concerned about how this change may impact the how the system responds to frequency excursions. Please refer to our comment in question 5.
Response: The GVSDT thanks you for your comment. Please see the response to your comment in Question 5.		
ACES Standards Collaborators	No	While we are not opposed to this change per se and do not offer any suggested alternatives, we would like to see a technical justification for why this is acceptable. The only rationale we can find is that the drafting team believes this is acceptable. No explanation for why this is acceptable was offered.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		
Independent Electricity System Operator	No	This should be confirmed with the UFLS designers in conjunction with PRC-006 and PRC-006-NPCC to see how this is coordinated with the frequency overshoot for that amount of time.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. This allowance has been in all drafts of the PRC-024 standard, so the UFLS designers should already have been aware of the possibility. Several regions already recognized the limitation created by the IEEE and IEC standards and have already adjusted their UFLS program requirements accordingly. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards. In the event a particular region believes the IEEE and IEC limits are unworkable, a more restrictive regional standard may be written to address the issue, but the GVSDT does not feel it is wise to mandate this across the continent.		
PPL Corporation NERC	No	

Organization	Yes or No	Question 2 Comment
Registered Affiliates		
ISO New England Inc.	No	
MRO NSRF	Yes	Could the drafting team please clarify the risk to the BES by leaving no margin for frequency overshoot? The NSRF was unsure if reducing the no trip margin above the IEEE / IEC design limits really represented a reliability risk to the BES. If generator units do overshoot the IEEE / IEC curve and remain on-line without damage, that doesn't appear to be a reliability risk. If the generator should trip to avoid damage from a frequency overshoot above the IEEE / IEC curve for which the unit was designed, that would also appear to be better for reliability, even if the unit does trip.
Response: The GVSDT thanks you for your comment. The potential risk would be to an area that may island with more generation than load (due to the configuration of the initial separation or due to load shedding) causing the frequency to rise. UFLS designers are supposed to limit the frequency overshoot to 61.8 Hz. Generators with overfrequency protection set to that value may trip, causing frequency to drop more dramatically than expected due to governor action. The GVSDT agrees with your assessment that preventing damage to generating equipment does improve reliability.		
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	

Organization	Yes or No	Question 2 Comment
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
We Energies	Yes	
Essential Power, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery	Yes	

Organization	Yes or No	Question 2 Comment
Company LLC		
Xcel Energy	Yes	
Cowlitz PUD	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has changed the time increment to 30 days in the VSL's for Requirements R3 and R4 (previously R5). Requirement R4 from Draft 5 has been removed.		

3. **In the previous draft of this standard the voltage ride-through curves in Attachment 2 extended out for 600 seconds before returning to normal operating voltages (95% – 105% of nominal). Also, the final step in the low voltage recovery curve was at 90% of nominal after three seconds. Commenters to the Generator Relay Loadability project pointed out that this could potentially cause conflicts with coordination of settings for relay loadability, since they need to be evaluated for stressed system conditions of voltages at 85% of nominal. In response, the drafting team has moved the final step of the low voltage recovery curve down from 90% to 85% at three seconds and has shortened the curves so that they end at four seconds. The drafting team believes this clarifies the intent of this standard to address the transient conditions without conflicting with relay loadability. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: Most stakeholders agreed with the revisions to the voltage ride-through curves in Attachment 2. Several stakeholders had concerns with the low voltage ride-through criteria being lowered to 85% for the 3-4 second interval. Stakeholders pointed out that transmission systems are designed to operate between 90% to 110% and not down to 85% and as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. The GVSDT agrees with these comments and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator).

Organization	Yes or No	Question 3 Comment
Southwest Power Pool Reliability Standards Development Group	No	We would like to see consistency between the voltage ride through curve and the off nominal frequency capability curve in the log scale. The last draft was consistent and we wonder why the drafting team changed the voltage ride through curve to a linear depiction?
Response: The GVSDT thanks you for your comment. The SDT believes that since the voltage curves were shortened to 4 seconds to address the transient conditions without conflicting with relay loadability, a linear depiction is adequate.		
ACES Standards Collaborators	No	(1) We support shortening the voltage curve to four seconds to reflect the purpose

Organization	Yes or No	Question 3 Comment
		of the standard to ride through voltage excursions which covers a transient time period. Furthermore, it reflects that the future PRC-025 will focus on steady state voltage limits. (2) We do not believe it is necessary to raise the performance bar for this standard by lowering the lower voltage curve to match the 0.85 pu voltage that is proposed to apply in the future PRC-025. First, having a requirement to ride through a voltage excursion to 0.9 pu for four seconds does not represent a conflict with PRC-025. It is simply less stringent than PRC-025. If PRC-025 requires more stringent performance using 0.85 pu for steady-state, that value can be set in that standard. Matching the proposed 0.85 pu in the proposed PRC-025 presumes that this is what the ultimate outcome of the PRC-025 standard will be. If PRC-025 were to end up with a 0.9 pu voltage requirement in the standard, then the standards again would not match. Second, no technical justification for changing the lower voltage ride through curve to 0.85 pu has been provided. If there is no technical justification to make the curve more stringent, it should not be made more stringent to simply match another proposed standard. Third, the overlap of the standards has been removed by striking load-affective protection functions such as impedance relays and voltage controlled overcurrent relays from this proposed PRC-024. How does the conflict in voltage performance exist when the standards apply to different equipment types? The load-affective protection will not be covered in proposed PRC-025 and will focus on steady-state conditions whereas the PRC-024 will focus on voltage excursions which are transient in nature and will apply to non-load affective protection performance.
Response: The GVSDT thanks you for your comment. In response to part 2 of the comment, The SDT agrees with your comment and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator).		
Alberta Electric System	No	The AESO disagrees with the use of 85% and supports the values as expressed

Organization	Yes or No	Question 3 Comment
Operator		previously in draft 4 of PRC-024-1. Transmission systems are designed to operate between 90% to 110% and not down to 85%, as such we do not expect generators to ride through voltages as low as 85% for an extended period of time. In particular, as NERC has left the 85% duration open ended, it is unclear how long a generating unit is to remain on-line under this condition. In addition, there appears to be a discrepancy in Attachment 2 where the "Curve Data Points" table identify a low voltage ride through duration of 600 seconds for <0.90 pu voltage and the "Voltage Ride Through Time Duration Curve" shows this to occur <0.85 pu voltage. Based on the explanation above, the table should be updated accordingly.
Response: The GVSDT thanks you for your comment. The SDT agrees with your comment and has revised the voltage ride-through chart 85% voltage level to the original 90%. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The Voltage Ride-Through Time Duration Table has been updated.		
CenterPoint Energy	No	CenterPoint Energy agrees with lowering the low voltage recovery curve down from 90% to 85% at three seconds; however, CenterPoint Energy is concerned with truncating the curves at 4 seconds due to undervoltage load shedding (UVLS) and relay loadability factors. For coordination with UVLS systems, CenterPoint Energy recommends the curve be extended to at least 10 seconds. Additionally, the purpose of relay loadability standards is to allow sufficient time for system operators to take corrective actions. Based on the purpose of relay loadability, CenterPoint Energy believes the curves should remain extended through 600 seconds.
Response: The GVSDT thanks you for your comment. Based on other industry comments, the chart has been returned to the 90% level found in the previous draft. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The SDT shortened the voltage curves to 4 seconds to address the transient conditions without conflicting with relay loadability standards. The		

Organization	Yes or No	Question 3 Comment
Voltage Ride-Through Time Duration Table has been updated.		
Consumers Energy Company	No	
Northeast Power Coordinating Council	Yes	The Curve Data Points table on page 18 of Draft 5 has not been updated to reflect the changes mentioned above.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
Dominion	Yes	Draft 5 Page 16 (clean version) the Curve Data Points table has not been updated to reflect the changes mentioned in question #3 above. Dominion agrees with the changes provide this modification is made.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
ISO New England Inc.	Yes	The curve data points chart was not revised when the drawing (including timescale) was revised. This leads to confusion however overall the change shown in the curve to 0.85 is acceptable.
Response: The GVSDT thanks you for your comment. The "curve data points" table of Attachment 2 has been corrected.		
MRO NSRF	Yes	The NERC generator relay loadability standards don't appear to state times, so changing the curves from 600 seconds to 3 and 4 seconds is a step in the right direction but could still lead to conflicts unless this standard or PRC-025 is amended. In a relay world that typically operates in cycles, 3 to 4 seconds is still a very long time and the NSRF believes that conflicts are still possible unless both standards are coordinated carefully. It is inappropriate to force entities to choose which standard to potentially violate. Please make sure that the associated graphs and curves data points within the table match each other.
Response: The GVSDT thanks you for your comment. Based on other industry comments, the chart has been returned to the 90% level found in the previous draft. This is due to removing all generator loadability relays from PRC-024 allowing the relay setting		

Organization	Yes or No	Question 3 Comment
criteria for loadability to be in PRC-025. The 85% point-of-interconnection voltage for relay loadability for transmission and generation relays remains in their respective standards (PRC-023 for transmission and PRC-025 for generator). The SDT shortened the voltage curves to 4 seconds to address the transient conditions without conflicting with relay loadability standards. The curve data points table of Attachment 2 has been corrected.		
Xcel Energy	Yes	(1) We agree with the changes made to the Voltage Ride Through Curve in Attachment 2. However, we note that the Curve Data Points table in Attachment 2 does not reflect corresponding updates, thus producing inconsistency between the graphic and tabular voltage ride through specifications. Please reconcile the differences to make both specifications consistent. **The curve data points table of Attachment 2 has been corrected.** (2) Suggest adding the prefix "POI" to the graph title such that it reads " POI Voltage Ride-Through...." - adding the prefix makes it explicitly clear that the curve does not apply to the generator terminal voltage. This clear distinction is important to eliminate potential confusion since the relay loadability options in PRC-025 allow using either POI voltage (85%) or generator terminal voltage (95%). **The prefix "POI" is used on the percentage of voltage legend on the right hand side of the graph in Attachment 2, the SDT believes this is adequate.** (3) Suggest enhancing the verbiage in the text-box in the voltage ride-through curve as follows to clarify that it applies to continuous operation and using "system adjustments" instead of "changes to the system". Suggested verbiage is: "Voltage for continuous operation (> 600 seconds) will be restored between 0.95 pu and 1.05 pu by automatic and/or manual system adjustments". **The curve is limited to 4 seconds in time and the GVSDT has removed the text box in question from the curve because it is no longer applicable.**
Response: The GVSDT thanks you for your comment. Please see responses to the individual comments above.		
IRC Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
Duke Energy	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
Bonneville Power Administration	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
We Energies	Yes	
Essential Power, LLC	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Tacoma Power	Yes	
Wolverine Power Supply	Yes	

Organization	Yes or No	Question 3 Comment
Cooperative, Inc.		
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Cogentrix Energy Power Management, LLC	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	
Cowlitz PUD	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the requested revision to the VSLs.		

4. **Footnote 1 has been revised to remove reference to impedance relays and voltage controlled overcurrent relays which are load-affected protective functions. This was done to remove overlap and potential conflict of coordination with the Generator Relay Loadability project. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The majority of comments were in agreement with the removal of loadability relays from PRC-024.

One commentator recommended that the Generator Relay Loadability drafting team vet the removal of these relay types from Footnote 1. The GVSDT had previous discussions with that drafting team and they concurred with the revision to PRC-024.

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	No	The standard clearly specifies in R1 and R2 that frequency and voltage relaying should not operate within "no trip zone". Footnote 1 should be completely removed since is only an incomplete list of the possible generator protections.
Response: The GVSDT thanks you for your comment. The footnote clarifies that a Generator Owner is not required to install frequency or voltage relaying as a result of this standard. The drafting team declines to remove Footnote 1 because it clarifies that generator relays or protective functions that have inputs of frequency and voltage are to be considered as part of PRC-024.		
CenterPoint Energy	No	CenterPoint Energy does not agree with removing references to impedance relays and voltage controlled overcurrent relays in Footnote 1, as we are concerned that there could be some differences between relay loadability and low voltage ride-through. Voltages at 85% of nominal and emergency current levels are used for calculating relay set points for relay loadability. For low voltage ride-through, impedance relays and voltage controlled overcurrent relays would need to be evaluated at voltage levels as low as 0% of nominal and at short circuit fault current levels. Instead of removing these relays from Footnote 1 at this late point in the development of PRC-024, CenterPoint Energy suggests that this be addressed by the

Organization	Yes or No	Question 4 Comment
		SDT for PRC-025 Generator Relay Loadability. The PRC-025 SDT has the appropriate subject matter expertise to fully vet whether these types of relays should be removed from PRC-024.
Response: The GVSDT thanks you for your comment. The drafting team discussed the loadability relays that were in PRC-024 with the PRC-025 drafting team before the recent posting. As a result of the discussion, it was agreed that PRC-025 would contain the necessary criteria for evaluating relay settings based on generator loading and field forcing along with 85% voltage at the point of interconnection. The voltage ride-through curve in PRC-024 has a voltage profile for voltage recovery after fault clearing and does not consider generator loading. The relay coordination draft standard (PRC-027) would take into consideration relay coordination between the Generator Owner and the Transmission Owner. Therefore, it was permissible to remove the loadability relays from PRC-024.		
PPL Corporation NERC Registered Affiliates	Yes	The PPL Companies also recommend the following changes to Footnote 1. The expression, “protective functions within control systems...based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, “known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer’s advisory.” Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
We Energies	Yes	The NAGF also recommend the following changes to Footnote 1. The expression, “protective functions within control systems...based on frequency or voltage inputs,” should be replaced with, “control system frequency or voltage trip setpoints.” It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip

Organization	Yes or No	Question 4 Comment
		within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Essential Power, LLC	Yes	We recommend the following changes to Footnote 1. The expression, "protective functions within control systems...based on frequency or voltage inputs," should be replaced with, "control system frequency or voltage trip setpoints." It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Cowlitz PUD	Yes	Cowlitz also recommends Footnote 1 be clarified concerning the expression "...protective functions within control systems that directly trip or provide tripping signals to the generator based on frequency or voltage inputs." It is unclear whether or not this statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. Cowlitz suggests a change to "...protective functions within control systems specifically programmed to provide frequency or voltage protection trip points..." This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and

Organization	Yes or No	Question 4 Comment
		when every contactor in a plant will drop-out for example is not possible.
Cogentrix Energy Power Management, LLC	Yes	The NAGF also recommend the following changes to Footnote 1. The expression, "protective functions within control systems...based on frequency or voltage inputs," should be replaced with, "control system frequency or voltage trip setpoints." It is unclear whether or not the present statement covers such events as contactor drop-out at extreme under-voltage or actuation of fan stall protection run-back during under-frequency operation. This change is important, because R2 allows units to trip within the no-trip zone only in accordance with R3, and R3 in turn pertains to a, "known equipment limitation...including (but not limited to) study results, experience from an actual event, or manufacturer's advisory." Tripping from unknown frequency or voltage-related limitations therefore evidently constitutes a violation, and predicting if and when every contactor in a plant will drop-out for example is not possible.
Response: The GVSDT thanks you for your comment. The GVSDT had follow-up conversations with members of the NAGF and reached a consensus on dealing with this issue. The GVSDT has revised R3 by adding "relay setting" into the requirement for clarity as follows: **R3. Each Generator Owner shall document each known regulatory or equipment limitation that prevents an applicable generating unit from meeting the *relay setting* criteria in Requirements R1 or R2 including (but not limited to) study results, experience from an actual event, or manufacturer's advisory.**		
Xcel Energy	Yes	(1) It is not apparent why the verbiage preceding and following the parenthetical text in Footnote 1 - that is, "Each GO is not required to have frequency or voltage protective relaying installed or activated on its unit." - Is essential. This applicability exclusion is sufficiently clear in the verbiage of the requirements R1 and R2, which states "Each GO that has generator protective relaying activated to trip its generating unit(s)...". Can a GO possibly activate a protective relay that is not installed? Therefore it seems redundant to include the applicability exclusion in the footnote and we suggest omitting it.

Organization	Yes or No	Question 4 Comment
		The footnote was intended to add clarity that a Generator Owner is not required to activate a protective function in a digital relay. For example, if a digital relay has an option to activate an under-voltage relay option and the Generator Owner elects to not use this function, this standard does not require the Generator Owner to activate and set it according to the ride through curve. (2) Suggest simplifying Footnote 1 as follows by retaining only the parenthetical text since it sufficiently captures the footnote's primary intent --- suggested footnote text is " 1 Including but not limited to frequency and voltage protective functions......... to the generator based on frequency or voltage inputs." **The footnote clarifies that a Generator Owner is not required to install frequency or voltage relaying as a result of this standard. The concept of "including but not limited to frequency and voltage protective functions" clarifies that the protection may be performed by a protective relay, or are protection options available inside a control system. The final portion of the sentence inside the parenthetical which states, "generator based on frequency or voltage inputs" defines whether the protective function is considered as part of the standard.**
Response: The GVSDT thanks you for your comment. See answers to your comments above.		
Northeast Power Coordinating Council	Yes	
Southwest Power Pool Reliability Standards Development Group	Yes	
IRC Standards Review Committee	Yes	
Dominion	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
MRO NSRF	Yes	
Bonneville Power Administration	Yes	
ACES Standards Collaborators	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
pacificorp	Yes	
Salt River Project	Yes	
Southern Company	Yes	
Hydro-Quebec TransEnergie	Yes	
Ameren	Yes	
Wisconsin Electric Power Company	Yes	
Tacoma Power	Yes	
Wolverine Power Supply Cooperative, Inc.	Yes	
ISO New England Inc.	Yes	

Organization	Yes or No	Question 4 Comment
Entergy Services, Inc. (Transmission)	Yes	
Liberty Electric Power LLC	Yes	
American Electric Power	Yes	
Manitoba Hydro	Yes	
Kansas City Power & Light	Yes	
Oncor Electric Delivery Company LLC	Yes	
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the requested revision to the VSLs.		

5. **Do you have any other comment, not expressed in questions above, for the GVSDT?**

Summary Consideration: Stakeholders provided valuable input regarding suggested improvements to language within the standard. Based on these comments, the following improvements were made to the draft standard:

- Removed Requirement R4 from the standards because of ambiguous language and dubious reliability benefit.
- Revised the title of the standard to "Generator Frequency and Voltage Protective Relay Settings" and the Purpose Statement to "Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions.
- Revised "generating unit(s)" to "applicable generating unit(s)" to reflect that the standard only applies to units that meet the registry criteria.
- ~~Revised language of R1 to match that of R2.~~
- Added "regulatory or" language regarding limitations to reflect that NERC, environmental or regulatory requirements may cause a limitation in generator performance.
- Revised Requirement R2 so that the sentences were shorter and easier to read, and made conforming changes to Requirement R1.
- Removed the last bullet from Requirement R3 and added and new bullet referencing frequency impacts on turbines as follows: "Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."
- Revised Requirement R5 (now R4) to indicate that the trip settings to be provided are only those "associated with Requirements R1 and R2" and not all relays.
- Revised the measures based on requirement revisions.
- Updated the VSLs for Requirements R3 and R4 to allow 30 day increments between levels rather than the original 10 days. This comports with other standards developed under this project.
- Updated the table in Attachment 2 (this was missed in the previous revision).
- Made clarifying revisions to "Voltage Ride-Through Curve Clarifications" on the last page of the standard.
- Clarified Footnote 3 to: "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

Organization	Yes or No	Question 5 Comment
Southern Company		1) Add the word "evidence" between "shall have" and "that" in M2 (to match the wording of M1). **The GVSDT agrees and has made the suggested revision.** 2) We believe that R4, due to the uncertainty of speculating the probability of the unit ride-thru/trip when exposed to transmission system voltage and frequency excursions described by Attachment 1 and Attachment 2, will not yield beneficial information in support of the BES reliability. **R4 has been removed from the standard.** 3) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. **R5, Draft 5 (R4, Draft 6) has been modified to clarify this: R4: Each Generator Owner shall provide its generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes is not required.** 4) Delete the word "nameplate" on item 1.b on the last page of the draft standard under "Evaluating Protective Relay Settings" for voltage excursions. The language "full real-power output" enables GOs to use the best "full load MW" values they have for their units for plant-specific studies. **Clarification #1 has been modified to allow flexibility in choosing the loading conditions for the unit under study. Please see the revision: Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting**

Organization	Yes or No	Question 5 Comment
		calculations on the static case for steady state initial conditions.
Response: The GVSDT thanks you for your comment. Please see responses above.		
ACES Standards Collaborators		(1) The data retention period is too long and is not consistent with the "Change State Element Paper No. 3 - Establish Compliance Data Requirements" whitepaper that NERC recently published as part of the reliability assurance initiative (RAI). It states that the retention period is the longer of three years or until the next audit. In effect, this makes the data retention period approximately six years since GOs are on a six year audit cycle. We believe this is simply too long a data retention period to demonstrate compliance and potentially refocuses audits on backwards looking changes that have no impact to reliability. Consider a generator that may undergo multiple setting changes. Is it necessary to retain all setting changes over this period or only the most recent ones that indicate the generator is currently set to ride through voltage and frequency excursions? Retaining historical settings that have been changed does nothing to support reliability and only perpetuates the paper driven compliance culture rather than a culture of reliability. **The GVSDT has used the boilerplate language provided by NERC Staff that is approved for use in standards. The whitepaper that you cite has not been approved for implementation. Auditors are still going to review the entire period until the RAI process is actually implemented and the burden is still on the entity to show compliance.** (2) This standard needs to be aligned with the recent NERC compliance enforcement initiatives (i.e. internal controls, entity impact evaluation, and elimination of zero-defect expectations). The VSLs for Requirements R1 and R2 could be read to require self-reporting of every unit that tripped for a voltage or frequency excursion inside the no trip zone. To refocus NERC efforts on compliance, the recent reliability assurance initiative would allow that GO to make this determination and correct any performance deficiencies without the need to self-report a violation. These approaches are being written into the standards (CIP, COM-003, etc.). We suggest

Organization	Yes or No	Question 5 Comment
		the drafting team coordinate with the appropriate NERC personnel to adopt a similar approach for this standard. **Requirements 1 and 2 are relay setting criteria requirements. Should there be an equipment limitation requiring that the relay settings of R1 and R2 be set in the "no trip zone" of Attachment 1 or 2, it is permissible to do so provided that the limitation is documented and communicated to the appropriate entity identified in R3. A violation of R1, R2, or R3 is either that the relays are not set according to the criteria of R1 or R2, or that documentation of the limitation (preventing the relays to be set according to R1 and R2) has not been communicated to the appropriate entity as required by R3.** (3) Because the voltage envelope is based on assumptions listed on page 19, the VSLs for R1 and R2 need to clarify that if a unit does trip in the no trip zone and the actual system conditions do not match these assumptions that the trip does not represent a violation. For instance, if a synchronous condenser or capacitor (bullet 2 under "Evaluating Protective Relay Settings" on page 19) is not available that was assumed to be available when evaluating protection relay settings, why would the GO be held accountable for its unit tripping during a voltage excursion? It followed the assumptions set out in the standard. **The clarifications have been revised to allow flexibility in the loading conditions when evaluating relaying settings. Please see the revised evaluation assumptions: "Use either the following assumptions or loading conditions that are believed to be the most probable for the unit under study to evaluate voltage protection relay setting calculations on the static case for steady state initial conditions."** (4) The response to our previous comments that requirement R3 and R5 are the types of requirements the Project 2013-02 Paragraph 81 drafting team is proposing to eliminate indicated that they do not meet criteria A. This implies that these requirements do provide significant reliability support. However, no justification for how they provide significant reliability support was provided. Please explain how a requirement such as R3 that requires documentation and communication supports

Organization	Yes or No	Question 5 Comment
		reliability. Requirement R1 already allows a GO an exception for documented and communicated equipment limitations. Because compliance is driven by evidence, the GO would have to document the limitation and communicate the limitation per the third bullet in Requirement R1. A separate requirement is simply not needed and "does little, if anything, to benefit or protect the reliable operation of the BES" above and beyond Requirement R1. The VSLs even seem to support this position since they focus primarily on the number of days late a registered entity has performed the task. Any further need to communicate the limitations could be rolled into the third bullet of Requirement R1. Requirement R5 is similarly situated requirement. Please explain how this requirement provides significant reliability support and, thus, does not meet criterion A. While we agree that generator protection settings changes need to be communicated, we simply do not see how a specific requirement to communicate them supports reliability. A requirement is not needed for every single task that should be completed. The requirement continues to perpetuate the paper driven compliance approach that NERC has recognized needs to change and is in the process of changing. If the drafting team believes, the requirement is still needed, we suggest including it as part of requirements R1 and R2. **Unless the GO indicates through communication to the TP (R3) that a particular unit will trip for voltage or frequency excursions not exceeding the "no trip zone" of the two attachments to the standard, the TP may not model the generator performance accurately, which may produce system simulations that are not valid. These erroneous studies could lead to actions (or inactions) that could affect system reliability.** **In the end, the requirement to document and communicate the limitations (and relay settings which are in the "no trip zone") have to be documented and communicated. It is more efficient to list these requirements once (in R3) rather than twice (in R1 and R2).**
Response: The GVSDT thanks you for your comment. Please see responses above.		

Organization	Yes or No	Question 5 Comment
Manitoba Hydro		(1) R4 - the word 'for' is missing between duration and which. **R4 has been removed from the standard.** (2) R4, second paragraph - the requirement hinges on what the GO 'expects' may happen, is very subjective. It will be hard for the MRO to measure compliance on this point. The phrase 'for the duration of the profile of the excursion' is new and not language that appears anywhere else in R4. It's not clear what it means. We would suggest using language that appears in the first paragraph of R4 so this is consistent. **R4 has been removed from the standard.** (3) R5 - allows the Planning Coordinator or Transmission Planner to request that settings must be provided within some time frame other than 60 days if they so direct. Theoretically this could be 1 day as there are no parameters put on what the PC or TP may direct. **The direction from the PC or TP was meant to be associated with the reporting of changes to the relay settings, not a change to the schedule. The requirement has been revised to clarify this: "Each Generator Owner shall provide its generator protection trip settings associated with Requirements R1 and R2 to the Planning Coordinator or Transmission Planner (that models the associated unit), within 60 calendar days of receipt of a written request for the data, and within 60 calendar days of any change to those previously requested trip settings unless directed by the requesting Planning Coordinator or Transmission Planner that the reporting of relay setting changes are not required."** (4) R5 - doesn't provide for a time frame other than 60 days which the requirement does. **The revision cited above addresses this concern.** (5) M2 - the word 'evidence' should be placed after 'have' and not after 'R2'. **The suggested revision has been made.**

Organization	Yes or No	Question 5 Comment
		(6) M3 - language doesn't seem to reflect revisions made to R3. For example, 'excluding limitations...' is still in M3 but deleted from R3. **Footnote 3 was revised to clarify the "excluding limitations…", and M3 has been revised to point to Footnote 3.** (7) M4 - language doesn't seem to reflect revisions made to R4. For example, the description of the generating units differs. **R4 / M4 have been removed from the standard.** (8) M5 - does not contemplate that it may be some time frame other than 60 days as R5 permits. **R5 has been revised to indicate that the "unless otherwise directed" phrase pertains to the reporting of changes rather than to the schedule.** (9) Compliance, 1.1 - CEA is used in the last sentence but never defined. The acronym is not used again, so it's likely easiest to not define it and use Compliance Enforcement Authority each time. **This has been corrected by adding (CEA) after Compliance Enforcement Authority in the first sentence.** (10) VSLs, R1 and R2 - the wording of the VSL is problematic as it ties the violation to a violation of R3 which the requirement itself does not do. **R1 and R2 specify exemptions to allow tripping in the "no trip zones" provided that the valid limitation is documented and communicated as specified in R3. Because this appears in R1 and R2, it is appropriate for it to appear in the VSL for R1 and R2.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Sacramento Municipal Utility District		1) Sacramento Municipal Utility District (SMUD) believes the applicability section should be revised to only cover those units defined by the BES Definition. As currently drafted Generator Owners that are registered under the NERC Registry

Organization	Yes or No	Question 5 Comment
		Criteria along with other non-registered generator owners are subject to this standard causing an enforcement issue. **While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"** 2) SMUD thanks the SDT for their response to our comment on R6 (now R5) during the last posting. However, SMUD wishes reiterate our disagreement with a requirement mandates ALL generator protection settings. SMUD also find it problematic to allow a single request by the PC or TP to create an indefinite requirement to report any relay change. SMUD believes R5 should be limited in its application to only frequency or voltage settings that directly correspond with the measure the PC or TP implement in their studies. **The scope of the relays whose settings are to be supplied to the PC and TP has been revised to limit the scope of relays as you suggest. The revised requirement reads: "R4. Each Generator Owner shall provide its applicable generator protection trip settings *associated with Requirements R1 and R2* to the Planning Coordinator or Transmission Planner that models the associated unit…"**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Wisconsin Electric Power Company		1. The word "evidence" is missing in Measure M2. Also in Measure M2, the wording should be changed to add the phrase, "... or other documentation", to the list of acceptable evidence for Requirement R2. Measure M1 allows "other documentation" as evidence, and this should be true for Measure M2 also. **"Evidence" has been corrected in M2.** **"or other documentation" has been added to M2.**

Organization	Yes or No	Question 5 Comment
		2. We disagree that the applicability of this standard needs to be to all generators regardless of size or connection voltage. Only generators connected to the Bulk Electric System should be applicable. The efforts needed to meet these requirements will be significant, and should not be required for every generating unit. Please verify your understanding of the referenced FERC order, because resources are limited. **While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Tennessee Valley Authority		1. The technical justification for the need of a plant performance criteria appears to be based on issues with early design wind generation. The technical considerations at these types of generation stations are different than steam turbine generation plants, which require heavy induction loads to support operation and these loads are sensitive to upsets in voltage and frequency. The technical implications of the plant performance are not clear. Recommend generating a separate SAR and bring in industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical academia, etc. to assist in the technical analysis and standard development. **That is the direction that the SDT has chosen to follow as Requirement R4 has been removed from the current draft of the standard.** 2. Likewise, industry technical SMEs such as IEEE, EPRI, Equipment OEMs, Power Plant Design entities, technical academia, etc. can develop acceptable methods to determine the capability of a plant to ride through grid transients.

Organization	Yes or No	Question 5 Comment
		That is the direction that the SDT has chosen to follow as Requirement R4 has been removed from the current draft of the standard. 3. The following are IEEE Electric Machines Committee comments for PRC-024-1considerationThe IEEE Electric Machinery Committee hosted a discussion topic on “Grid Code Impact on Electric Machine Design” in San Diego at this year’s Power Engineering Society meeting and offers the following input. o Minor changes in the Under-frequency Ride Through Curve are suggested to better match existing machine design standards in IEEE C50????. o The PRC-024 Voltage Ride Through criteria is technically not ready to be a standard, for the following reasons;1. PRC-024 VR capability may not be available at any price. BES reliability enhancements requiring technological advances should be addressed with industry groups (e.g. ASME, IEEE) and OEMs to develop commercially available products before appearing as requirements in reliability standards. It is believed the cost of complying with wider standards might increase main generator machine costs as much as25%, which is not insignificant. This should only be required if there is a defined local system need for higher standards and that these costs should be considered against the cost of other possible resolutions.2. A specific concern in this respect regarding the ride-through capability being sought in PRC-024 R3-5 is that auxiliary buses may drop-out and cause a unit to trip for the excursions specified, which go well beyond the industry's present design criteria, even if the protective relay settings nominally allow such transients. It may be unrealistic to expect that the dynamic behavior of all 4160V and 460V systems in new plant can be dynamically modeled to a degree allowing one to obtain non-dropout guarantees from equipment suppliers and EPC firms for extreme transients such as 2.0 seconds at 65% voltage, or that the same can be done for existing plants to allow identification of limiting components and accurate estimates of performance.3. The voltage ride through was originally intended to address early deficiencies in wind generation design only and it doesn’t make sense to apply such a broad curve to steam plants. The concerns

Organization	Yes or No	Question 5 Comment
		that led to the VRT curve for wind have been addressed by new vintage wind plant designs and thus, the EMC does not believe there is not driving need for a standard VRT criteria. o The VRT issue is holding up addressing other significant issues addressed by PRC-024 (relay setting coordination and frequency ride through). The VRT should be pulled out of PRC-024 and a new SAR drafted to address the voltage performance aspects if this is really needed for reliability. o More clarity in defining plant MVARs available to support grid voltage is needed. Specifically, generation plants have not been designed to operate outside a normal band of 95 to 105% on the generator terminals. GSU settings are typically chosen to optimize MVAR support under normal operations, however is not reasonable to assume the full leading or lagging reactive support would be available under normal grid conditions. **R4 has been removed from the current draft of the standard. The standard is now essentially a relay setting standard only. Generator performance requirements may or may not be dealt with in the future in other developments projects.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Duke Energy		a) The effective date in Section 5.1.4 should be increased to seven years. The typical major outage cycle for base load units can be as long as 7 to 9 years, based upon the unit and its history. **The SDT believes that five years is the correct number. The SDT notes that the maximum allowable interval for relay calibration in PRC-005-2 is six years. In addition, the SDT believes a major outage would not be necessary to effect a change in relay settings if that is what is necessary to comply with this standard.** b) In the “Consideration of Issues and Directives” document, it is stated that the

Organization	Yes or No	Question 5 Comment
		GVSDT believes that R3 allows NRC requirements to supersede portions of the voltage and frequency ride through criteria in PRC-024-1, and that NRC requirements qualify as technical limitations for the purposes of this standard. We believe that additional clarity is needed in the text of Requirement R3 regarding allowable limitations other than equipment limitations, such as NRC technical specification limits and perhaps environmental permit limitations as well. **The SDT agrees and has added the words "…regulatory or…" before "… technical equipment limitation…" to address your concern.** c) Additional clarity is needed in Requirement R4. Is R4 intended to serve as a means to obtain more information from a Generator Owner about limitations identified pursuant to R3? Is the voltage or frequency profile to be provided by the Planning Coordinator or Transmission Planner different from Attachments 1&2? **Requirement R4 has been removed from this standard.** d) Requirement R4 states that the Generator owner may develop estimates based upon "sound engineering judgment". R4 should more clearly indicate the extent of "due diligence" effort that is expected in order to support an estimate based on "sound engineering judgment". **Requirement R4 has been removed from this standard.** e) On Attachment 2, Evaluating Protective Relay Settings, 1.c states that "Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals." We believe that compensating all generator voltage relaying for a loading of rated power at 0.95pf lagging is dangerous, as this could indicate coordination margin to the HVRT when there is none. The worst case coordinating conditions for the HVRT are not the same as for the LVRT. The current version of the standard is prescribing a method that will lead to miscoordination between the HVRT curve and overvoltage relays (59 & 24 elements). We recommend generator undervoltage relaying be evaluated at rated power at rated power factor, and generator overvoltage relaying be evaluated at rated power at .95pf leading. There

Organization	Yes or No	Question 5 Comment
		can be more than a 10% difference in POI voltage under these two sets of conditions. **The cited clarification specified the initial condition for the generator prior to an event that causes a voltage excursion. The words "… or loading conditions that are believed to be the most probable for the unit under study…" have been added to allow evaluation of the relay settings under conditions other than full load at 95% lagging power factor.** f) In the VRF and VSL Assignment document, the R6 should be corrected to R5 (typo) **The typo has been corrected.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Cowlitz PUD		(A) Confusion is created by making exemptions, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% over speed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed.****** (B) The rationale for the last bullet item of R3.1 (reporting a 10% increase in

Organization	Yes or No	Question 5 Comment
		nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor mass flow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available.****** (C) Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.****** (D) The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported

Organization	Yes or No	Question 5 Comment
		trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
Essential Power, LLC		a. Confusion is created by making exemptions, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow

Organization	Yes or No	Question 5 Comment
		uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. d. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
We Energies		a. Confusion is created by making exemptions, "in accordance with Requirement R3," in R1 and R2 of PRC-024-1; while R3 excludes, "limitations that are caused by generator frequency and voltage protective relays." Are such "protective relays" meant to correspond to the "protective relaying" discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is

Organization	Yes or No	Question 5 Comment
		intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, "Excludes limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed. b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant

Organization	Yes or No	Question 5 Comment
		blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. d. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.
PPL Corporation NERC Registered Affiliates		Confusion is created by making grandfathering (exceptions), “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any grandfathering is actually being allowed. It has been said in discussions with the SDT that there is no grandfathering of voltage-relaying or frequency-relaying intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations is in fact where our over/under-frequency protection system settings come from. If a turbine OEM notifies us that a unit must trip within one second at 2.5% overspeed, for example, then our 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes

Organization	Yes or No	Question 5 Comment
		limitations that are caused by the generator frequency and voltage protective relays themselves." Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on historical practice with an unknown technical basis, a more direct way of saying so should be developed. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn't be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. It would be acceptable if R3.1 or a footnote stated that "Resubmittal of the exemption documentation when reporting a 10% increase in nameplate capacity is required, but the removal of the exemption status is not required as part of the 10% increase in nameplate capacity." Steam turbine off-frequency limits are generally set by OEMs as lifetime limits

Organization	Yes or No	Question 5 Comment
		regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation. The scope of the generator protection trip settings reported in R5 should be limited to the protective relaying specified in R1, R2, and footnote 1. It is believed that responding to a request for data is acceptable, but the burden of having to provide an additional response within 60 days of any change to previously reported trip settings is unduly burdensome. It is believed that recurring requests by the PC or TP should be the mechanism for additional reporting.

Response: The GVSDT thanks you for your comment.

a. The GVSDT has decided to retain footnote 3 as it is a necessary clarification to Requirement R3. We have revised the footnote 3 to address your comment: "Excludes limitations that are caused by setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."

b. We have removed the last bullet from R3.

c. Requirement R3 provides the exemption for equipment limitations, which include off-frequency limits. Accrued off-frequency excursions are a valid equipment limitation and would be addressed in Requirement R3 but it is not required that this be done. We have added a bullet to R3 as: "• Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."

d. The GVSDT intended for this requirement to include only those relays. We have added "associated with Requirements R1 and R2" to the requirement.

e. The GVSDT does not think that reporting relay setting changes within 60 days of a change is a burden. The TP and PC need to be made aware of the changes as soon as practical.

Organization	Yes or No	Question 5 Comment
Cogentrix Energy Power Management, LLC		a. Confusion is created by making exemptions, “in accordance with Requirement R3,” in R1 and R2 of PRC-024-1; while R3 excludes, “limitations that are caused by generator frequency and voltage protective relays.” Are such “protective relays” meant to correspond to the “protective relaying” discussed above? It is semantically unclear whether or not any exemptions are actually being allowed. It has been said in discussions with the SDT that no grandfathering of voltage or frequency relaying is intended, and exemptions covered in R3 are for other equipment limitations such as low frequency sensitive turbine blades. This only adds to the confusion, however, since equipment limitations are (or at least should be) where over/under-frequency protection system settings come from. If a turbine OEM states that a unit must trip within one second at 2.5% overspeed, for example, then the 81O relay is set for 60 cycles at 61.5 Hz. We believe that R1, R2 and R3 would be completely harmonious if the SDT were to remove footnote 3, “Excludes limitations that are caused by the generator frequency and voltage protective relays themselves.” Alternatively, if the intent was to require that settings have a grounding in equipment limitations and not be based on guesswork or corporate policy, a more direct way of saying so should be developed . b. The rationale for the last bullet item of R3.1 (reporting a 10% increase in nameplate capacity) is unclear, and it could be interpreted as requiring that units previously having restrictions be pulled into no-exemptions status. This is an appropriate course of action where possible, and increasing fossil unit output 10% is likely to require replacing the L0 blades, in which case achieving Att. 1 compliance shouldn’t be a problem for the less-demanding interconnections. These components might not pass muster in the West (no instantaneous tripping until 57.0 Hz), however, and some designs would definitely not qualify in Quebec (55.5 Hz). This could be even more of an issue for the very long L0 blades of nuclear units. Regarding gas turbines, firing temperature increases and compressor massflow uprates (e.g. zero-staging) can cause the 10% threshold to be reached without necessarily affecting original-unit frequency limits, particularly if dealing with a new model that was initially rated at substantially less than the expected capability

Organization	Yes or No	Question 5 Comment
		pending confirmation of prototype unit performance in service. Expanding the frequency range for this type of equipment may not be feasible, since there is often no alternative to OEM blading (especially for the more recent models). That is, one cannot shop around for blading with PRC-024-compliant resonance avoidance. The issue also involves compressor surge margin at low speed and turbine overload at high speed, which may lock-in original frequency restrictions even if more-tolerant blading becomes available. c. Steam turbine off-frequency limits are generally set by OEMs as lifetime limits regarding duration, but there is no discussion in PRC-024-1 as to how often the specified excursions may occur. Our understanding is that it is acceptable for units that once met Att. 1 of PRC-024 to start reporting (and periodically increasing) will-trip exceptions as fatigue life is progressively consumed, but it would be best to make this matter explicit in the standard rather than requiring each GO to formulate its own interpretation.
Response: The GVSDT thanks you for your comment. **a. The GVSDT has decided to retain footnote 3 as it is a necessary clarification to Requirement R3. We have revised the footnote 3 to address your comment: "Excludes limitations that are caused by setting capability of the generator frequency and voltage protective relays themselves but does not exclude limitations originating in the equipment that they protect."** **b. We have removed the last bullet from R3.** **c. Requirement R3 provides the exemption for equipment limitations, which include off-frequency limits. Accrued off-frequency excursions are a valid equipment limitation and would be addressed in Requirement R3 but it is not required that this be done. We have added a bullet to R3 as: "• Creation or adjustment of an equipment limitation caused by consumption of the cumulative turbine life-time frequency excursion allowance."**		
Associated Electric Cooperative, Inc. - JRO00088		AECI appreciates this SDT's demonstrated attention to industry feedback. Draft 5 PRC-024 R1 Bullet 3, COMMENT: AECI appreciates this "catch-all" being in there, and we hope it is worded to adequately cover any other technically justifiable

Organization	Yes or No	Question 5 Comment
		plant relay settings the SDT failed to mention, that intentionally operate within the industry's Attachment 1 No Trip zones. However we are concerned that R1's and Bullet #3's collective wording may specifically exclude any other protective relay settings outside of Bullet #1 and Bullet #2, including those specifically designed for other plant equipment limitations. (R2 Bullets #3 & #4 seem to provide better flexibility for what we failed to think of in this draft 5.) **Response: The SDT did add the additional qualifier in R1 Bullet 3 for "regulatory…..limitations" to remove any confusion that the allowance of tripping is not just limited to equipment limitations. Also, by NERC standard convention, a "bullet list" allows the entity to select which of the bulleted verbiage applies. Thus, the 3rd bullet would exclude the exceptions that are written in the first or second bullet.** Draft 5 PRC-024 page 14, Attachment 1, Curve Data Points:, Eastern Interconnection, COMMENT: It just seems that even without a fluctxuating frequency profile, the Eastern Interconnection's frequency-bounded curves, functionally-declared within that table's middle-row, can make a calculation for compliance with Requirements R1 & R4 a bit challenging. (Page 17's first bullet#3, providing clarity around evaluating step-wise voltage excursions, provided some insight into what is currently drafted for Requirements R1 and R4 in conjunction with Attachment 1, where these continuous Eastern Interconnection curves are in play, and actual plant performance studies and results are analyzed.) While we expect to evaluate plant performance only around our known discrete plant relay settings, we are a bit concerned for the way this Standard's non-discrete duration-functions might be leveraged against the industry when actual events occur. **Response: Since the Eastern Interconnection curve can be expressed by linear equations, which can be compared to the discrete plant relay settings, the SDT believes there isn't any risk of confusion of expected versus actual relay action during an event.** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications,

Organization	Yes or No	Question 5 Comment
		Curve Details:, Bullet3:, REPLACE: “voltage exceeds", WITH: “voltage first exceeds”, RATIONALE: Further clarity as to why duration is only 0.1 seconds in this example. **Response: The SDT has incorporated your suggestions** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-through Curve Clarifications, Curve Details:, Bullet4:, REPLACE: “proportion to deviations of frequency below normal “, WITH: “proportion to below-normal deviations within the provided frequency profile", RATIONALE: Clarity that adjustment is made for study-related frequency profiles provided in conjunction with a request, and not for immediately experienced voltage deviations as they occur. **Response: In response to your and other industry comments, the SDT has modified the verbiage in Item 4 to reflect that a) this adjustment is associated with the determination of appropriate volts per hertz protection settings and b) by use of the qualifier “may”, that this is a suggestion and not a requirement.** Draft 5 PRC-024 page 17, Attachment 2, Voltage Ride-Through Curve Clarifications, Evaluating Protective Relay Settings:, Bullet 1.c. REPLACE: “terminals).”, WITH: “terminals.”, RATIONALE: Balanced parentheticals **Response: The SDT has corrected the typo.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Tacoma Power		Applicability should only be to those units meeting NERC registration criteria. **Response: While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word “unit(s)” in the requirements was modified to read “applicable unit(s)”** Per Footnote 4, the “point of interconnection means the transmission (high voltage) side of the generator step-up or collector transformer.” As the SDT is probably

Organization	Yes or No	Question 5 Comment
		aware, many generator protective relays measure voltage on the generation (low voltage) side of the transformer. It seems that guidance may be needed to reconcile generation (low voltage) side measurements with a standard whose requirements are based upon transmission (high voltage) side voltage. **Response: The SDT recognizes that the voltage ride through curve will have to be reflected through the transformer in order to determine the resulting voltage ride through curve that will be "seen" by the associated relays that are connected to instrument transformers on the generator side. Please reference Attachment 2 (Evaluating Protective Relay Settings section) for additional guidance regarding the assumptions that are expected to be made.** In R2, the phrase "less stringent" may not be clear enough language. For example, could "less stringent" mean 96-104%, rather than 95-105%, which is our assumption? Or, could it mean 94-106%? **Response: The SDT believes that the entire phrase clearly conveys the intent (less stringent voltage relay settings than those required to meet PRC-024 Attachment 2). It is meant to include the time period of the first 4 seconds.** Why are auxiliary systems mentioned in R4 but not in R1, R2, and R5? **Response: The SDT has removed R4. As such, auxiliary systems are no longer mentioned in any of the remaining requirements.** In R5, remove parentheses around "that models the associated unit." The parentheses seem to be inconsistent with similar text in R4. **Response: The SDT implemented your suggestion.** In M2, move 'evidence' to before "that generator voltage..." **Response: The SDT implemented your suggestion.** Attachment 2, Curve Detail 3, may need some better clarification. **Response: The SDT did slightly refine the language for clarity by inserting the word**

Organization	Yes or No	Question 5 Comment
		"first" into the second line (reference response to Associated Electric Cooperative, Inc for Question 5) Regarding Attachment 2, Curve Detail 4, does that mean a GO must base relay settings on the lowest expected frequency deviation? What is an example of how and when Detail 4 should be applied? **Response: The SDT modified the language to reference that an adjustment of the magnitude of the high voltage curve in proportion to deviations of frequency below normal should optionally occur when evaluating volts per hertz settings.** Regarding Attachment 2, Curve Detail 5, by stating "RMS or crest", does this mean that a GO must consider harmonics? Most simulations only consider the fundamental frequency component. In these cases, the per unit crest and RMS voltage should be identical. Clarification is requested. Examples are needed to support the application of Attachment 2, Evaluating Protective Relay Settings. **Response: In that the high-voltage curve establishes the minimum voltage at which a unit may be tripped by its protection, the original wording allowed consideration of the maximum of crest and RMS voltage. Having this provision makes the standard less limiting. There was no requirement for a GO to consider non-fundamental frequency voltages, there was permission to use peak-sensing or RMS-sensing protections (whether implemented via protective relays or via protections as part of controls). The information in Curve Detail 5 poses no burden on the GO, but rather allows a GO to provide better or more effective protection of certain types of equipment, if they choose to do so. To help provide clarity regarding the application of Attachment 2, the SDT revised the chart to provide ride-through durations at the associated voltage points.** R1, R2, and the diagram in Attachment 2 appear to be fairly straightforward. However, the Voltage Ride-Through Curve Clarifications page (last page) seems to confuse, not clarify. This last page seems to undermine the apparent simplicity of the rest of the standard with respect to voltage protective relay settings.

Organization	Yes or No	Question 5 Comment
		Response: The SDT has made a number of refinements to the Voltage Ride-Through Curve clarification page such as a) modified the language to convey in the Curve Detail section Item 4 that an adjustment of the magnitude of the high voltage curve in proportion to deviations of frequency below normal should optionally occur when evaluating volts per hertz settings, and b) modifying the Evaluating Protective Relay Settings section to allowing the responsible entity the ability to assume the most probable loading conditioning, and clarifying that the AVR should be assumed to be in service. In Attachment 2, the Curve Data Points table needs to be updated to reflect the Voltage Ride-Through Time Duration Curve. Tacoma Power appreciates the opportunity to provide comments, and thanks you for consideration of our comments. **Response: The SDT has corrected the Table to reflect that it is applicable up to 4 seconds.**
Response: The GVSDT thanks you for your comment.		
Arizona Public Service Company		APS agreed with the draft Standard however, we voted no because of the Violation Severity Levels (VSL) associated with this Standard. Only 10 days spacing between various levels of the VSL is inappropriate and not justified. A 30 days delay in providing the requested information does not represent a significant reliability risk. In addition, other draft Standards, for example Project 2007-09 MOD and PRC-019, provides a 30 to 90 days separation between various levels of the VSL. In our opinion each VSL severity level should be at least 30 days apart.
Response: The GVSDT thanks you for your comment. The GVSDT agrees and has made the suggested revision to the VSLs.		
Bonneville Power Administration		BPA believes that the standard should combine bullet 3 into bullet 2 in R3.1 (and modify bullet 3 to notify when equipment has been replaced for whatever reason) o Identification of an equipment limitation. o Repair or replacement of the

Organization	Yes or No	Question 5 Comment
		equipment causing the limitation that removes the limitation. o Replacement of the equipment causing the limitation. (modification)
Response: The GVSDT thanks you for your comment. The SDT developed the bullet items during the last posting based on stakeholder comments. The GVST believes that we have achieved stakeholder consensus on this language.		
CenterPoint Energy		CenterPoint Energy does not agree that a Planning Coordinator or a Transmission Planner should be required to provide a voltage or frequency profile at the point of interconnection that is determined by dynamic simulation and, instead, recommends that the voltage or frequency profiles in Attachment 1 and Attachment 2 be referenced. Different types of simulated events will produce different voltage and frequency excursions. Also, even the same type of event will produce different voltage and frequency excursion “profiles” as the system changes over time. Therefore, the voltage or frequency profiles in Attachment 1 and Attachment 2 should be used.
Response: The GVSDT thanks you for your comment. The wording in Requirement R2 gives the Planning Coordinator or Transmission Planner the option to provide a site-specific voltage profile, but does not require that it be done. Requirement R4 contained wording that required the PC or TP to provide a profile to the Generator Owner before asking for an estimate of ride-through time, but Requirement R4 has been removed from the standard.		
Cleco		Cleco is concerned the approach is too prescriptive given the numerous variables associated with generator performance and protection. We recommend the elimination of requirements R1 and R2 in their entirety. **The SDT disagrees with this suggestion. These two requirements form the backbone of this standard. The UFLS standard (PRC-006-1), in particular, refers to PRC-024-1 for information and proper setting of generator frequency protection.** We further recommend requirement R3 be modified so that the generator owner is required to develop a unit capability curve for frequency and voltage based on equipment limitations and protection requirements and provide this information to

Organization	Yes or No	Question 5 Comment
		the appropriate users. This approach emphasizes equipment preservation and safety while retaining predictability of unit performance for system modeling. We would also like an example for how to evaluate Volts/Hertz protection for the proposed voltage curve. **The SDT disagrees that drafting multiple sets of unit capability curves for different frequencies and voltages would be of value. The capability curves are meant for steady state operation, not the transient conditions considered in this standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Kansas City Power & Light		Comment 1;Generator protective relays are connected to the potential transformers on the generator side of the GSU transformer. The interconnection point is defined by the standard on the transmission side of the GSU. The voltage and frequency charts in the attachments are requirements at the interconnection point. Therefore the standard prevents the use of existing generator protective relays for voltage or frequency protection. The standard and attachment charts should be redrafted to represent the interconnect point on the generator side of the GSU so existing multifunction relays can be used for voltage and frequency protection. **The SDT disagrees that the standard prevents the use of existing generator protective relays, but it would require the evaluation of the voltages at the generator terminals that result from the described transmission system voltage excursions based on the specific transformer tap, transformer impedance, and generator reactance. Because of these variables, the SDT does not believe the voltage excursion curves can be described for all generators at the generator terminal level.** Comment 2; Requirement 5 states “Generator Owner shall provide its generator protection trip settings to the Planning Coordinator, etc”. In the context of this standard I would assume that generator protection trip settings would be those settings relative to voltage or frequency protection and for example would not

Organization	Yes or No	Question 5 Comment
		include back up distance settings. The standard should be modified to clarify which generator protective relay settings are required for compliance. **The SDT agrees. The words "… associated with Requirements R1 and R2…" have been added to clarify the scope of the requirement.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Consumers Energy Company		Consumers Energy is resubmitting our original comments as we feel they still pertain. "Related to undervoltage criteria, the 18 cycle at 45% of generator voltage would put a great deal of strain on the plant auxiliary systems and that may not be something these systems are able to withstand. The same would be true of a fault that produces 65% voltage at the generator terminals for 2 seconds. These comments relate specifically to Consumers Energy. However, it is likely that many others have similar equipment and would have the same issues. Please also note that the proposed standard does not align with ANSI C37.102, IEEE Guide for AC Generator Protection or with the NERC Technical Reference Document entitled Power Plant and Transmission System Protection Coordination." Previous SDT reply - Thank you for your comments. Please note that the voltage levels specified in Attachment 2 are at the point of interconnection to the transmission system. They would not correlate directly with the auxiliary bus voltages, especially if the auxiliaries are unit-connected. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. Please inform the SDT of the specifics of your concerns." We believe our comments still apply. Specific to the fault that produces 65% voltage at the generator terminals for 2 seconds, plant auxiliary equipment would not be able to withstand such a drop for the specified duration and would fall offline.SDT Reply - The SDT thanks you for your comments. The SDT does not believe this proposed standard is in conflict with either the IEEE or the NERC documents cited. The SDT believes that the wording of R4, "The Generator Owner may develop the estimates based on experience, actual event histories, or sound engineering judgment," will allow the GO to provide an estimate. However, if the GO feels his equipment is not

Organization	Yes or No	Question 5 Comment
		capable of meeting the undervoltage criteria of Attachment 2, then R3 would apply. Also, note that Attachment 2 has been modified for the next draft and now only extends to 4 seconds.
Response: The GVSDT thanks you for your comment. The GVSDT points out that the voltage shown in attachment 2 is at the Point of Interconnection and not at the generator terminals. This is shown in the axis label on the right side of the curve.		
Exelon Corporation and its affiliates		Exelons negative vote is based on the following: Exelon reiterates that nuclear generating units must comply with a rigorous process of evaluation to meet requirements of the Nuclear Regulatory Commission (NRC). The response by the SDT in the Consideration of Comments dated 12/7/12 that “the SDT does not believe extensive studies or dynamic simulations are required to comply with this requirement” does not address the fact that NRC licensed nuclear generating units must also comply with the requirements of the NRC. Exelon again does not agree that 60 calendar days is a reasonable amount of time to perform any such analysis.
Response: The GVSDT thanks you for your comment. The words “regulatory and” have been added in several locations throughout the standard to emphasize the exemptions from the requirements specified in R1 and R2 are allowed for both regulatory limitations and technical equipment limitations. Please review these modifications to R1, R2, and R3. Also, the GVSDT has removed the requirement to provide an estimate of the time duration a unit is expected to remain connected during a voltage or frequency excursion.		
Idaho Power Company		Idaho Power’s Power Supply group feels that Requirements 1 through 4 accomplish the purpose of PRC-024 and that Requirement 5 is not necessary and in fact creates an on-going obligation for the generation owner to continually provide relay settings to the Transmission Planner within 60 days of any change to those settings regardless of the relay setting changes impact on reliability and even if the changed settings remain in compliance with R1 and R2 of the standard. However, Idaho Power’s System Planning group feels that Requirement 4 is not a sufficient mechanism to collect the desired data and removal of R5 will limit the Planning Authority’s ability to request relay modeling data from both Idaho Power and non-Idaho Power Generator

Organization	Yes or No	Question 5 Comment
		Owners. **R4 has been deleted from the draft standard. The relay setting communication requirement (R5, draft 5) is now R4 (draft 6). The scope of relays whose settings may be requested has been clarified in the new R4. The GVSDT does not think that reporting relay setting changes within 60 days of a change is a burden. The TP and PC need to be made aware of the changes as soon as practical.** R5 will make it a compliance obligation for GOs, to provide the required data when requested by a PA/PC or TP in a timely manner, or following a change in relay settings on a generator for which said data had previously been requested. Idaho Power notes the Measure 2 should read: Each Generator Owner shall have evidence that generator voltage protective relays have been set in accordance with Requirement R2 such as dated setting sheets, voltage-time curves, calibration sheets, coordination plots or dynamic simulation studies."Idaho Power comments that reference to the Planning Coordinator entity throughout the PRC-024 standard should be replaced with the term Planning Authority to be consistent with the NERC Glossary of Terms. **Please see version 5 of the NERC Functional Model and the current NERC Glossary of terms, both of which identify the PC as the correct term. The term Authority is being transitioned to Coordinator.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
IRC Standards Review Committee		In order for the industry to support the proposed change to the high frequency trip curve in Attachment 1, we propose that the SDT provide the technical justification and an assessment of the system impacts as a result of the proposed change so operators are aware of and manage the resultant system response. We believe the standards should be based upon actual technical data rather than conditions represented in the IEEE and IEC standards.
Response: The GVSDT thanks you for your comment. Since virtually all generators in North America are built to IEEE C50.13 and/or IEC 60034, the GVSDT believes that, absent the change in the high frequency curve, Generator Owners who decide to set		

Organization	Yes or No	Question 5 Comment
overfrequency protection would claim the exemption allowed under Requirement R3 to set the protection to meet the IEEE or IEC standard. The GVSDT further believes that the NERC reliability standards should respect existing industry technical standards.		
MRO NSRF		In R3, the NSRF recommends that 30 day requirement be replaced with "in a timely manner not to exceed 90 days". This is predicated on the low VRF and low risk of impacting the BES. While some deadlines are necessary in NERC standards, large frequency and voltage excursions are rare and there would be little to no reliability difference if R3 changes were communicated in a time frame longer than 30 days. **The SDT believes that once it has been determined that an additional notification from the GO to the PC and TP is necessary, the 30 days allowed for notification is not burdensome.** In R3, the fourth bullet, delete (cumulative from the first effective date of this standard). This creates an unnecessary compliance tracking burden. Entities must forever memorialize all equipment capability from the effective date of the proposed standard such as 2014. There is no reason to track all possible equipment changes in 2044 back to 2014 to show that a 10% upgrade has not occurred is pieces throughout the years. Transmission and generation upgrades are usually lumped and somewhat large as it is usually cost prohibitive to increase generator capability. The reliability benefit is to recognize when a large change in the limitation occurred, not to track a cumulative 10%. Is the SDT referring to only the limiting element that needs to be tracked? **This bullet has been deleted from the draft standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Avista		Most frequency relays have voltage supervision. There is no voltage supervision requirement for frequency relays specified in the standard. For the voltage relay settings the ride through is given as 9 cycles at 0 volts. Where did the 9 cycles come from?

Organization	Yes or No	Question 5 Comment
Response: The GVSDT thanks you for your comment. The frequency and voltage protection are considered to be different functions so the voltage ride through and frequency ride through are not expected to happen at the same time. It is not the intent of the SDT or this standard to specify the relay design, merely the coordination of the protection settings with the standard or equipment or equipment limitations, whichever is more restrictive. The nine cycle time came from the WECC studies performed relating to the voltage ride through characteristics and FERC Order 661A (Appendix G).		
ReliabilityFirst		ReliabilityFirst votes in the affirmative for this standard because the standard further enhances reliability by ensuring that generating units remain connected during frequency excursions. Even though ReliabilityFirst votes in the affirmative, we offer the following comment for consideration: 1. Requirement R3 Part 3.1 a. To be consistent with the changes made to Requirement R4 and new R5 (removal of Reliability Coordinator and Transmission Operator), ReliabilityFirst recommends removing references to the Reliability Coordinator and Transmission Operator from Requirement R3 Part 3.1 as well. Requirement R3 is long-term planning requirement and communication of the documented equipment limitations to these entities should not be required.
Response: The GVSDT thanks you for your comment. The SDT agrees and has removed the Reliability Coordinator and Transmission Operator from Requirement R3 and the associated VSLs as well as the Purpose Statement.		
seattle city light		Seattle CIty Light, from a GO perspective, will vote NO, because it is unclear the type of data the TP is to provide the GO. Until the TPs agree to and approve acceptable simulations and dynamic models, it is difficult for us to approve this standard.
Response: The GVSDT thanks you for your comment. The SDT has decided to remove Requirement R4 from the standard so any reference in Requirement R4 to the frequency and voltage profiles which were to be provided by the Planning Coordinator or Transmission Planner is no longer valid. Requirement R2 allows the Transmission Planner to provide a less stringent voltage profile than that in Attachment 2 if they feel it is more appropriate.		
Xcel Energy		Suggest improving consistency between R1 and R2 verbiage by addressing the

Organization	Yes or No	Question 5 Comment
		following editorial comments: (a) Not sure why the qualifying phrase "... as a result of voltage excursion (at the point of interconnection)..." is used in R2 but no corresponding qualification is used in R1? If this specificity for voltage excursion is needed in R2, then shouldn't it also be needed for frequency excursions in R1? **A voltage excursion would be location specific and is referenced to the point of interconnection as opposed to the generator terminals where the measurement would be significantly different A frequency excursion is different and may be measured the very nearly the same no matter where it is viewed in the interconnection. For the GO, there would be no difference measuring the frequency either at the generator terminals or at the point of interconnection. For these reasons the qualifying phrase was necessary for Requirement R2.** (b) Re-order the bulleted exceptions under R1 and R2 such that they appear in the same sequence in both requirements - this will make it easier for the uninitiated reader to observe that R1 and R2 share 3 common exceptions and R2 has one additional exception. **The SDT feels that changing the order will add little to the readability, even for the uninitiated and therefore prefer not to change the order and confuse those already initiated.** (c) Readability and comprehension of R2 will be significantly enhanced if it is simplified by splitting it into 2 or more shorter sentences. Its existing structure - a very long, compound sentence of more than 100 words - is not conducive to easy comprehension and is prone to ambiguities in interpretation, leading to compliance confusion. **The SDT agrees and has revised Requirement R2 into multiple sentences for enhanced readability. Requirement R2 now reads in part:** **"Each Generator Owner that has generator voltage protective relaying activated to trip its generating unit(s) shall set its protective relaying such that the voltage**

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		protective relaying does not trip as a result of a voltage excursion (at the point of interconnection) caused by an event on the transmission system external to the generating plant that remains within the "no trip zone" of PRC-024 Attachment 2. If the Transmission Planner allows less stringent voltage relay settings than those required to meet PRC-024 Attachment 2, then the generator owner shall set its protective relaying within the voltage recovery characteristics of a location-specific Transmission Planner's study. Requirement R2 is subject to the following exceptions: ……" (d) R1 states "Each GO.... shall set <such> protective relaying <so> that the.... does not <operate to> trip" whereas R2 states "Each GO..... shall set <its> protective relaying <such> that the.... does not trip". It is hard to detect any good reason for the choice of words <such> and <so> in R1 versus <its> and <such> in R2, or for choosing to say <operate to> trip in R1 versus omitting that phrase in R2. Suggest identical lead-in sentences unless there is a good reason for the variations. **The SDT agrees and has modified the wording in Requirement R1 to match that in Requirement R2 as suggested.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Oncor Electric Delivery Company LLC		The 60 calendar day requirement in Requirement 5 for a Generator Owner to respond to a written request from its Transmission Planner or Planning Coordinator for generator protection trip settings, is too long. Because of the critical nature of this information, prolonging assessing system coordination can result in an unnecessary risk to the reliability of the Bulk Electric System. Oncor requests that this time requirement be shortened to 30 days.
Response: The GVSDT thanks you for your comment. The SDT considers this standard to be on a unit basis and that 60 days should be adequate for any single unit.		

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Wolverine Power Supply Cooperative, Inc.		The applicability should be restricted to BES generating units, not all units.
Response: The GVSDT thanks you for your comment. While the Applicability of Generator Owners conveys that units meeting the NERC registration criteria, and thus the BES, only are subject to the standard, for additional clarity, the SDT has inserted additional explicit language. Specifically, as appropriate, the use of the word "unit(s)" in the requirements was modified to read "applicable unit(s)"		
Ameren		The SDT has addressed all of our comments by changing several items that improve the standard, and especially important to us was removing R5 & M5. However, the SDT did not alter the VSL from the 10 day escalation for R3 through R5, and used the NERC guidance as their reason. NERC guidance also allows for a population based severity escalation, which we believe is more appropriate for characterizing the severity in situations such as this, and so we recommend using this approach. We suggest allowing up to 5% for Low, 5 to 10% for Moderate, 10 to 15% for High, and greater than 15% for Severe. For example, change the R4 Lower VSL to "The Generator Owner provided an estimate for less than 100% but more than 95% of its units' performance within 60 calendar days of a written request" and change R4 Moderate VSL to "The Generator Owner provided an estimate for 95% or less, but more than 90% of its units' performance within 60 calendar days of a written request."
Response: The GVSDT thanks you for your comment. As a result of other stakeholder comments the SDT has removed Requirement R4. The SDT views this standard on a unit basis and not a fleet basis so the percentage basis would be inappropriate. The SDT however did modify the VSL's for Requirements R3 and R5 (now R4) to match the 30 day escalation in some of the other generator verification standards of Project 2007-09.		
Appelbaum		The VRF for R1 and R2 should be High not Medium. The Drafting team in the VRF justification document states [Start quote] This requirement is similar in concept with both PRC-012-0 Requirement R1 and PRC-023-1 Requirement R1, both of which require protection coordination or settings. These requirements apply to multiple

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		elements while the requirements of PRC-024-1 apply to a single unit. Violation of this requirement by a single generator could not be construed as directly causing or contributing to BES instability, separation or cascading within any time frame. For a single violation to lead to BES instability, separation or cascading would require other standards requirements to be violated.[End Quote] I disagree with the assertion. PRC-023 is violated if one relay is incorrectly set regardless of the number of elements it is protecting. The same applies to PRC-024, a failure to set one relay will effect one generator. Also for PRC-023 a single violation would not lead to BES cascade but that reasoning did not prevent a VRF of High to be established for PRC-023. Applying consistent reasoning to PRC-024 would mean that the single generator argument to reduce the VRF to medium would not apply.
Response: The GVSDT thanks you for your comment. The justification for the VRF must include all of the reasoning and guidelines referenced in the justification document. The VRF's were previously changed from high to low based on the following comment from a previous posting, "We do not believe the VRFs for Requirements R1, R2 and R5 warrant High VRFs. The BES is already operated within each BA and TOP for the loss of a single unit. Tripping of a generator due to a frequency or voltage excursion is an uncommon event that is already planned for. It is highly unlikely that tripping of such a generator or even several generators will lead to instability, system separation or cascading which is required for the VRF to be High. Furthermore, by setting the VRF to High, this increases the potential that every single unit outage could become subject to a Compliance Violation Investigation which is simply not necessary." This comment was accepted by the SDT and since yours was the first and only objection; the SDT believes industry consensus has been achieved.		
American Electric Power		We agree with the overall approach taken, however we are concerned that the standard repeatedly references "protective relaying" while Footnote 1 clarifies that protective relaying could be discrete relays as well as protective functions within control systems. The term "protective relay" is widely accepted amongst engineers as meaning a discrete relay. AEP recommends the SDT utilize the term "protective functions" throughout the standard to clearly identify that the scope of the standard extends beyond discrete relays.AEP recommends that the time allowed to meet R 3.1 be extended to 60 calendar days, aligning it with R4 and R5.

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		The SDT has included the clarification in Footnote 1 to point out that the use of protective relaying as intended in this standard includes those functions that might not normally be recognized as "protective relaying". The SDT purposely did not use the term "protective functions" throughout so as not create confusion over other protective functions found in control systems such as overspeed trips that might be found in turbine controls. AEP recommends R4 and R5 be revised to read "within 60 calendar days or an agreed upon schedule". The data sought by the PC or Transmission Planner might be quite large for some utilities. In this case, it would be advantageous to allow the GO to work with the requesting party to develop a timeline that meets the needs of the requesting party without being overly burdensome to the GO. We believe the intent of the SDT in requiring the GO to provide updates on any previously requested trip settings in R5 was to ensure that the PC and TP are notified of any changes to the R1 and R2 applicable trips. If this is accurate, we suggest revising R5 to require the GO to update the PC and TP within 60 days of installation of new trips or changes to existing trips to which R1 and R2 applies, not solely those trip settings previously requested by the PC and TP. Doing so removes the obligation of the GO to track which trip settings were part of a previous request. This change will also eliminate the possibility of the TP or PC not being made aware of a newly installed applicable trip within a timely fashion. **The SDT has decided to eliminate R4 from the standard, which is perceived to be your primary concern, due to other stakeholder comments. The Requirement in R5 to submit settings that should already be on file within 60 days is not considered by the SDT to be burdensome.** Should the 10 percent generator nameplate capacity increase stipulation in the last (fourth) bullet point under R3.1 be removed? We do not see that the stipulation is relevant to the question of what limitation is causing a given generating unit to not satisfy R1 or R2 criteria. Perhaps the point should read as follows: "Modification or upgrade of the equipment causing the limitation that removes or changes the

Organization	Yes or No	Question 5 Comment
		limitation." **The SDT agrees and has removed the referenced bullet from Requirement R 3.1.** With reference to R4, would it make sense for the TP or PC to specify Attachments 1 and 2 as the profiles for the purpose of collecting time duration estimates, or should the term "profile" instead be "trajectory"? From the viewpoint of the TP or PC, receiving duration estimates with respect to the Attachments would be advantageous, particularly when coordinating generator off-nominal frequency tripping with UFLS. However, a single duration estimate seems more compatible with a frequency or voltage trajectory. Which is the SDT's intent? **As a result of stakeholder comments the SDT has decided to eliminate Requirement R4 from the standard.**
Response: The GVSDT thanks you for your comment. Please see responses above.		
Ingleside Cogeneration LP		While we were pleased to see the removal of R5 from PRC-024, there is still some question as to the basic necessity for this standard, PRC-001, now PRC-027, requires extensive coordination of protection system relay setting between GOs and TOs. Interconnection agreements also require following voltage schedules, etc. This is a case of over regulation and potential conflicts between standards, something Paragraph 81 initiative is supposed to oppose. Also, there is no explicit FERC directive that requires this standard.
Response: The GVSDT thanks you for your comment. As stated in the purpose, this standard is intended to "Ensure Generator Owners set their generator protective relays such that generating units remain connected during defined frequency and voltage excursions." and is not for the coordination of protection settings among entities (PRC-001.1). There is no approved PRC-027but even its draft is primarily related to coordination of interconnected elements. Industry determined in the SAR, as a result of the Phase III and IV testing that the standard was needed. Standards are not usually directed by FERC but determined by SAR's.		
Liberty Electric Power LLC		Yes. First, the standard as presented is greatly improved from the prior version. The hard work of the SDT is apparent. However, there still are a few issues which should

Organization	Yes or No	Question 5 Comment
		be resolved with the standard. First, the 10% trigger for removing exemptions is too low. GE markets products for their gas turbines which can raise output more than 10% through software changes. This could place a turbine into no exemptions space while it still contained blades subject to failure at frequencies within the no trip zone. The 10% threshold should be raised or the standard reworded to note that software changes do not trigger the requirement. **The SDT agrees and, with the elimination of R5 from the previous revision, has decided that the 10% trigger found in Requirement R 3.1 no longer applies. Therefore the bullet containing the 10% trigger has been eliminated from the standard.** Secondly, the phrase "manufacturers advisory" is too vague. One reasonable person may read the phrase as "a statement in the OEM materials which places limits on the frequencies the machine can tolerate", while another reasonable person would define it as "a specific bulletin or technical information letter which advises of a finding about the equipment". GE 7FA OEM documents, for example, state that the turbine is "very sensitive to abnormal frequencies" and that recommendations "should be carefully studied and followed". Would this document, coupled with an engineer determining an overfrequency relay setting of 60.5 with 60 cycle delay, be enough to allow that setting? Would something like this be subject to individual auditor determination? If the latter is true, the wording should be changed, as requirements should clearly guide the entity in making a determination of the allowable action. **We have revised the word "advisory" to "advice" to help clarify the issue and address your concern.** Finally, if a steam turbine which is driven by steam generated from gas turbine exhaust is required to trip within the no-trip zone due to equipment limitations, does this allow those gas turbines to trip within the no trip zone also, in order to prevent damage to the steam turbine condenser? Can their protective settings for overfrequency be set at the same point as the required steam turbine settings, or

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		would an entity have to add logic to their system to trip in response to the activation of the steam turbine overfrequency trip instead of their own overfrequency relay? **The standard in no way suggests that the unit should be operated in a manner which is detrimental to the equipment. An exemption would include any part of the unit (gas turbines in a combined cycle unit for this case) that should be tripped to protect the equipment if it is a documented limitation.**
Response: The GVSDT thanks you for your comment. Please see responses above.		

END OF REPORT