Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements — Project 2010-13

The Revisions to Relay Loadability for Order 733 SAR Drafting Team thanks all commenters who submitted comments on the proposed SAR and an initial set of proposed requirements. The SAR and proposed standard were posted for a 30-day public comment period from August 19 through September 19, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 36 sets of comments, including comments from more than 88 different people from approximately 36 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The Standard was posted for an "informal" comment period – the team provided a summary responses to the comments submitted on the proposed standard (Questions 1-8) and the SAR was posted for a "formal" comment period - and the team provided detailed responses to the comments submitted on the SAR (Questions 9-13)

Summary of Changes:
The SDT revised sections 4.1.2 and 4.1.4 for consistency and to refer to facilities "determined by the Planning Coordinator to comply with this standard."
The SDT added a new 4.1.3 "Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard. "

The SDT renumbered old 4.1.3 to 4.1.4.

The SDT renumbered old 4.1.4 to 4.1.5 and reverted the voltage threshold to the original text consistent with the modification to section 4.1.2.

The SDT added "4.1.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard."

In response to comments that Requirement R5 is confusing the SDT deleted "to prevent cascading when protective relay settings limit transmission loadability" from Requirement R5. Removing this does not change the intent of the requirement.

Commenters indicated for a variety of reasons that the requirement related to out-of-step blocking added to Requirement R1 is confusing. The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

Some commenters indicated that the word "settings" should be replaced throughout R1 when referring to a part, or sub-requirement of R1. The SDT modified Requirement R1 by replacing the word "settings" with "criteria." This is consistent with the main Requirement R1 which in the presently approved standard (PRC-023-1) refers to sub-requirements R1.1 through R1.13 as criteria to prevent phase protective relay settings from limiting transmission system loadability.

Some commenters identified an error in the draft standard in criterion 9 in Requirement R1 that resulted in omitting a phrase contained in the presently approved standard. The SDT modified criterion 9 in Requirement R1 to reinsert the deleted phrase.

IEEE C37.91 Figure A5 has two components to the thermal damage curve for through-faults: the "thermal component" begins at 2x the transformer nominal nameplate rating, and seems to be the root of commenters' concerns. The "mechanical component" begins at a current equal to the reciprocal of the twice the transformer impedance. The commenters are correct in their characterization of the "thermal component" of the transformer damage curve, in that it is not possible to satisfy the posted PRC-023-2 R1, criterion 10 and also protect the transformer for currents in this region. Upon careful consideration of FERC Order 733, the SDT revised R1 criterion 10 to reference only the mechanical withstand capability.

Many commenters questioned the inclusion of "limiting piece of equipment" rather than "transformer", as the fault-withstand capability of terminal equipment (switches, breakers, current transformers, etc) may be unavailable. Upon further consideration of FERC Order 733, the SDT modified criterion 10 by replacing "limiting equipment" with "transformer."

The SDT modified the wording of R4 as follows. "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide...." as a result of comments.

The SDT agreed to remove the Regional Entity from the list of entities receiving this information in Requirement R4.

One commenter noted that the SDT needs to work closely with the Reliability Coordination SDT (Project 2006-06) which is tasked with defining critical facilities or indentifying criteria for developing a list of critical facilities. The commenter disagreed with use of the phrase "facilities that are critical" in this requirement and cautioned that a requirement to create a list of critical facilities should not be addressed in this standard. The SDT notes that although the phrase "critical to reliability of bulk electric system" appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase "critical to reliability of the Bulk Electric System" in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in PRC-023 - Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

One commenter noted that Requirement R5, Part 5.1 is unnecessary since the process to use the criteria in PRC-023 - Attachment B would almost certainly be to simply apply the criteria and that requiring documentation of such a process will result in increased paperwork and additional preparation for an audit without a reliability benefit. The SDT agrees that this part of Requirement R5 is unnecessary and has removed it from the Standard.

Three-fourths of commenters believe the addition of section 1.6 in PRC-023 - Attachment A is not an equally efficient and effective method of meeting this directive. More than one-half of commenters believe that addressing the directive in the proposed manner will have a negative impact on reliability of the bulk electric system. The SDT agrees that addressing the directive in the manner proposed in the first posting will have the unintended consequence of impacting the dependability and security of certain protection systems. The SDT has revised the draft standard to address the following concerns noted by commenters.

- More than one-half of commenters noted that the proposed modification would require overcurrent fault detectors applied to supervise distance (impedance) elements to meet the relay loadability requirements which would have a detrimental impact on reliability. Setting these fault detectors to meet PRC-023 would restrict the ability of some distance elements to trip for end-of-zone faults, particularly on weak source systems. Eliminating the fault detector to avoid this concern would have the negative impact of making the protection system susceptible to undesired tripping during close-in faults on adjacent elements. Some commenters further noted that many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled.

- Several commenters noted that the standard should apply to protective systems and not to individual components of protective systems and that compliance should be based on the ability of the protective system as a whole to meet the performance criteria established by the standard. Some commenters also noted that a clarification is required that “protective functions” applies only to those protective relay elements that would respond to non-fault or load conditions and could issue a direct trip.

- Some commenters noted their belief that the modification goes well beyond the Commission’s concern and they proposed alternatives they believe would be equally effective and efficient approaches to addressing the Commission’s reliability concerns.

In response to these concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to include “1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications.” The SDT also modified the second bulleted item in section 2.1 to add the clause, “except as noted in section 1.6 above.”

The SDT agrees with several commenters about the proposed language for Effective Dates and has changed the language to the following:

5.1. Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability, the first day of the first calendar quarter 12 months after applicable regulatory approvals.

5.1.2 For supervisory elements as described in Attachment A, section 1.6, the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals.

5.3. Requirements R4 and R5: the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals.

To address the need for entities to meet the requirements of the standard for facilities identified by the Planning Coordinator in the future, the SDT added a new requirement (R7).

Several commenters indicated that the directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. This was an error in the SAR and the SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

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

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

Index to Questions, Comments, and Responses

The Industry Segments are:

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

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	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	NY State Reliability Council	NPCC	10
2.	Gregory Campoli	NY Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Gerry Dunbar	NPCC	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	7
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian L. Gooder	Ontario Power Generation	NPCC	5

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

9. Kathleen Goodman	ISO New England	NPCC	2
10. Chantel Haswell	FPL Group Inc	NPCC	5
11. David Kiguel	Hydro One Networks	NPCC	1
12. Michael R. Lombardi	Northeast Utilities	NPCC	1
13. Randy MacDonald	New Brunswick System Operator	NPCC	2
14. Bruce Metruck	NY Power Authority	NPCC	6
15. Lee Pedowicz	NPCC	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. Saurabh Saksena	National Grid	NPCC	1
19. Michael Schiavone	National Grid	NPCC	1
20. Peter Yost	Consolidated Edison of New York	NPCC	3
21. Mike Garton	Dominion Resources	NPCC	5

2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	1, 3, 5, 6

Additional Member	Additional Organization	Region	Segment Selection
1. Alvin Depew	Potomac Electric Power Company	RFC	1
2. Carl Kinsley	Delmarva Power & Light Company	RFC	1
3. Evan Sage	Potomac Electric Power Company	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Rob Wharton	Atlantic City Electric	RFC	1									
3.	Group	Kenneth D. Brown	PSEG Companies	1, 3, 5, 6									
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Dave Murray	PSEG Power	RFC	5									
2.	Jim Hebson	PSEG ER &T	NPCC	6									
3.	Scott Slickers	PSEG Connecticut	NPCC	5									
4.	Jerzy Slusarz	Odessa power Partners	ERCOT	5									
5.	Jim Hubertus	PSEG	RFC	1,3									
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6									
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Dean Bender	BPA	WECC	1									
5.	Group	Doug Hohlbaugh	FirstEnergy	1, 3, 4, 5, 6									
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Sam Ciccone	FE	RFC	1, 3, 4, 5, 6									
6.	Group	Ben Li	IRC Standards Review Committee	2									
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Bill Phillips	MISO	MRO	2									
2.	Patrick Brown	PJM	RFC	2									
3.	James Castle	NYISO	NPCC	2									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10									

4.	Greg Van Pelt	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Mark Thompson	AESO	WECC	2

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corp	MRO	3,4,5,6
4.	Jason Marshall	Midwest ISO	MRO	2
5.	Jodi Jenson	Western Area Power Admin.	MRO	1,6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1,3,5,6
9.	Joseph Knight	Great River Energy	MRO	1,3,5,6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3,4,5,6
11.	Scott Nickels	Rochester Public Utilities	MRO	4
12.	Terry Harbour	Mid American Energy Co.	MRO	1,3,5,6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Mike Garton	Dominion Electric Market Policy	1, 3, 5, 6									
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Michael Gildea	Dominion Resource Services	NPCC	5									
2.	Louis Slade	Dominion Resource Services	SERC	6									
9.	Individual	Brent Ingebrigtson	E.ON U.S. LLC	X		X		X	X				
10.	Individual	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				
11.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
12.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
13.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
14.	Individual	Andy Tillery	Southern Company	X		X							
15.	Individual	Bill Middaugh	TSGT System Planning Group	X									
16.	Individual	Gene Henneberg	NV Energy	X		X		X					
17.	Individual	Steve Wadas	NPPD	X									
18.	Individual	Joylyn Faust	Consumers Energy			X	X	X					
19.	Individual	Jonathan Meyer	Idaho Power - System Protection	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
21.	Individual	Dan Rochester	Independent Electricity System Operator		X								
22.	Individual	Bill Miller	ComEd	X		X		X					
23.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
24.	Individual	Brian Evans-Mongeon	Utility Services								X		
25.	Individual	Tribhuwan Choubey	Southern California Edison	X									
26.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
27.	Individual	Kathleen Goodman	ISO New England Inc.		X								
28.	Individual	Robert Ganley	Long Island Power Authority	X									
29.	Individual	Kirit Shah	Ameren	X		X		X	X				
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Michael Moltane	ITC Holdings	X									
32.	Individual	Not indicated	Not Indicated										
33.	Individual	Laura Zotter, Steve Myers	ERCOT ISO		X								
34.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
36.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

1. **The Applicability Section (4.1.2 and 4.1.4) and Requirement R5 (previously Requirement R3) have been modified to address the directive in Paragraph 60 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

Several commenters wanted to know what is meant by “critical to the reliability of the Bulk Electric System (BES)”. The SDT notes that although the phrase “critical to reliability of bulk electric system” appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase “critical to reliability of the Bulk Electric System” in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase “critical to the reliability of the bulk electric system” with “that must comply with this standard.” The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

Several commenters indicated that the phrase "low voltage terminals" is open to interpretation. This term is part of the existing standard and not included in the scope of the SAR; however, Attachment B will clarify the criteria to determine which facilities must comply with the standard.

The SDT revised sections 4.1.2 and 4.1.4 for consistency and to refer to facilities “determined by the Planning Coordinator to comply with this standard.”

Commenters indicated that they did not believe the standard should apply to facilities below 100 kV; however, in Order 733, NERC was directed to apply PRC-023 to facilities below 100 kV, as well as 100 kV to 200 kV, and to provide criteria to establish which of those facilities to which PRC-023 was to apply. As noted with this posting, the criteria was posted for public comment and is intended to be included with the next posting of this standard.

Commenters indicated that they did not believe the standard should apply to facilities below 100 kV; however, in Order 733, NERC was directed to apply PRC-023 to facilities below 100 kV, as well as 100 kV to 200 kV, and to provide criteria to establish those facilities to which PRC-023 was to apply. As noted with this posting, the criteria were posted for public comment and will be included with the next posting of this standard.

Commenters were reluctant to offer a firm response to the proposed modifications without reviewing the proposed criteria in Attachment B. As noted with this posting, the criteria were posted for public comment and will be included with the next posting of this standard.

The SDT reverted the voltage threshold in section 4.1.2 to the original text because commenters suggested that only facilities below 100 kV that are on the Regional Entity’s list should be subjected to the criteria in Attachment B, while all facilities between 100 kV and 200 kV should be subject to the criteria in Attachment B.

The SDT added a new 4.1.3 “Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard. "

The SDT renumbered old 4.1.3 to 4.1.4.

The SDT renumbered old 4.1.4 to 4.1.5 and reverted the voltage threshold to the original text consistent with the modification to section 4.1.2.

The SDT added "4.1.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard."

In response to comments that Requirement R5 is confusing the SDT deleted "to prevent cascading when protective relay settings limit transmission loadability" from Requirement R5. Removing this term does not change the intent of the requirement.

Commenters indicated that the modifications to the applicability section may have the unintended consequence of increasing the burden on Distribution Providers (DPs) with no reliability benefit; however, 1) the proposed modifications are directed changes and 2) the DPs would only be affected if the Planning Coordinators apply the criteria in Attachment B and determine that the DPs have a facility that must comply with the standard.

One comment indicated that Requirement R1's VRF "High" has no justification. The SDT thinks that the revision to Requirement R1 to include below 200 kV facilities should have no impact on the VRF assignment. If a facility is designated as a facility critical to the reliability of the BES the impact on reliability is High regardless of the voltage level.

Some commenters noted the Reliability Coordinator (RC) is included in the SAR, but the SDT did not include the RC in the applicability section of the standard. The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The revised Applicability paragraph 4.1.4 reads:4.1.4 Transformers with low voltage terminals connected below 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System (BES). The phrase "low voltage terminals" is open to interpretation because some transformers have low-voltage terminals which are do not supply a load, or supply only local substation AC service. Sometimes the transformer is a 3-winding bank, with the low-voltage winding not used, or the low-voltage winding is used solely to provide additional grounding, as in the case of a delta-connected tertiary, unconnected to any load. Is this what is intended? If yes, then they should remove the ambiguity. Note the phrase "low-voltage" terminal was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV raises the new concern. What is meant by "critical to the reliability of the Bulk Electric System (BES)"? Also, replace "as designated" with "and designated".Suggest 4.1.4 be revised to read:4.1.4 Transformers with low voltage terminals connected below 200 kV and designated by the Planning Coordinator as Critical Assets. Clarification is needed to explain the disconnect between FERC's "sub-100kV", and the proposed "below 200kV".
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made

Organization	Yes or No	Question 1 Comment
		clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) It is not clear what a "critical facilities list identified by the Regional Entity" is as specified within the order so addressing the directive is a challenge. This standard is not the appropriate venue for development or consideration of a critical facilities list. There is a supplemental SAR in process for the Reliability Coordination project that is to address that topic. 2) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can't be the intent.3) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60, "We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate." It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC's performing their assessment for below 200 kV facilities. This standard is not the appropriate venue to determine or revise a critical facilities list, nor is it appropriate for a Regional Entity to establish such a list. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.
MRO's NERC Standards Review Subcommittee	No	However, this response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Dominion Electric Market Policy	No	It depends on what Attachment B (R5.1) requires once it is developed. Without knowledge of the final content developed for Attachment B, we do not support this.
E.ON U.S. LLC	No	E.ON U.S. believes that it is confusing the way R5 is currently written due to the last part of the sentence " ... when protective relay settings limit transmission loadability." There is a need for clarification on how this is to be applied. As an alternative: If the directive is to have the Planning Coordinator determine which sub-100kV facilities should be subject to the Reliability Standard; R5 should be modified to read "Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities in its Planning Coordinator Area are to be included in 4.1.2 and 4.1.4."
Transmission Access Policy Study Group	No	The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in TAPS' response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential

Organization	Yes or No	Question 1 Comment
		for confusion and unnecessary costs.
Arizona Public Service Company	No	Agree with the content. However, there is no justification for VRF to be High for the circuits lower than 200 kV.
Kansas City Power & Light	No	Agree the changes for 4.1.2 and 4.1.4 are effective in meeting the “add in” approach in the FERC order. However, do not agree with the approach in R5. R5 proposes to establish the criteria by which Reliability Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria.
Utility Services	No	The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in our response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential for confusion and unnecessary costs.
ISO New England Inc.	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can’t be the intent.2) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60, “We also direct that additions to the Regional Entities’ critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.” It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC’s performing their assessment for below 200 kV facilities. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.

Organization	Yes or No	Question 1 Comment
Long Island Power Authority	No	There appears to be a disconnect between FERC's "sub 100 kV" and proposed "below 200 kV" revision in the Applicability Section. LIPA seeks clarification on this. Also, by whom and by which method will the criticality of the substations be ascertained?
Ameren	No	Attachment B as mentioned in R5 is not available for review.
American Electric Power	No	AEP understands the intent of the FERC Order (Paragraph 60) to address the sub-100 KV facilities only if they are associated with critical facilities above 100 KV. The applicability and the associated requirements should be reworded to ensure that the Planning Coordinator does not have to identify critical facilities below 100 KV.
Southern California Edison	No	Applicability clause 4.12 and 4.14 - Formulating a consistent methodology test to determine for a sub 200KV facility by the Planning Coordinator is quite an uphill task keeping in view the different circuit configuration different utilities may have. It is best left alone to each utility to determine the facilities which can be a candidate for inclusion as a bulk power system. The current risk based assessment criteria to determine bulk power facility should be continued.
American Transmission Company	Yes	However, this affirmative response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Pepco Holdings, Inc - Affiliates	Yes	While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology once it is developed.
NPPD	Yes	As long as you keep BES.
Independent Electricity System Operator	Yes	We agree with the Applicability Section and the modification to R5. Note that there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

2. R1 has been modified to address the directive in Paragraph 244 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

Summary Consideration:

Commenters indicated for a variety of reasons that the requirement related to out-of-step blocking added to Requirement R1 is confusing. The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

One commenter noted that it is not clear how loadability requirements apply during fault conditions. In the new requirement the SDT clarified that the evaluation must ensure that out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

Some commenters indicated that the word “settings” should be replaced throughout R1 when referring to a part, or sub-requirement of R1. The SDT modified Requirement R1 by replacing the word “settings” with “criteria.” This is consistent with the main Requirement R1 which in the presently approved standard (PRC-023-1) refers to sub-requirements R1.1 through R1.13 as criteria to prevent phase protective relay settings from limiting transmission system loadability.

Some commenters identified an error in the draft standard in criterion 9 in Requirement R1 that resulted in omitting a phrase contained in the presently approved standard. The SDT modified criterion 9 in Requirement R1 to reinsert the deleted phrase.

One commenter noted that this directive needs to be addressed by a full standard drafting team to adequately address this directive and identify equally effective alternatives to the Commission’s directives. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process.

One commenter indicated that they agreed with the inclusion of Section 2 of Attachment A in the Requirement Section but the proposed modification may not fully meet the directive that the additional requirement is assigned a VRF and VSL. This may require the creation of a separate main requirement rather than simply including the condition as a part of a requirement. However, the VRFs and VSLs are associated directly with R1, and thus all its’ subparts/criteria. Therefore, as Attachment A is referenced as being part of R1, the R1 VRFs and VSLs automatically apply.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	1. The last sentence in R1 should be revised to read: Each Transmission Owner, Generator Owner, and Distribution provider shall evaluate relay loadability at 0.85 per unit voltage, and a power factor angle of 30 degrees. 2. Settings are to be applied as listed following:”Setting” should be replaced throughout R1 when referring to

Organization	Yes or No	Question 2 Comment
		a part, or sub-requirement of R1. The terminology should be whatever is preferred by NERC.Requirement R1, Parts 7, 8 and 9: 3. Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" 7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system condition.8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system condition.9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the [___] to the under any system condition. [Brackets added, also see further comment on missing wording following]This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern. 4. Requirement 1, part 9:As currently written, Requirement 1, part 9 states:9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the [___] to the under any system configuration. [Brackets added]Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
Pepco Holdings, Inc - Affiliates	No	The revised wording in paragraph R1 regarding out-of-step blocking schemes is confusing. We suggest rewording the paragraph by splitting the sentence as follows: ...while maintaining reliable protection of the BES for all fault conditions. Use of out-of-step blocking schemes shall be evaluated to ensure that they do not block tripping for faults during the loading conditions defined within these requirements.
Bonneville Power Administration	No	The modified Requirement R1 requires that one of the 13 criteria be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. The problem is that the 13 criteria are only related to loading conditions, and it is not clear how they would be applied to prevent out-of-step blocking schemes from blocking a trip during a fault, or if it is even possible to use these criteria for this purpose. The modified Requirement R1 requires actions that are ambiguous and we cannot support it as written.
IRC Standards Review	No	We believe this directive needs to be addressed by a standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team

Organization	Yes or No	Question 2 Comment
Committee		could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others.
E.ON U.S. LLC	No	Since correct operation of the out-of-step blocking feature is integral to and only a single component of a successful trip operation (for fault conditions), this is already included in the requirement to “maintain reliable protection of the BES for all fault conditions” and does not have to be mentioned separately. Also, R1 (as written) may be interpreted to require one of the settings (1 through 13) to be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. But Settings 1 thru 13 do not address specific setting criteria for out-of-step blocking.
TSGT System Planning Group	No	We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is “Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs.”
NV Energy	No	The proposed phrase added to R1 is only a start: “. . . , and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions.” The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay’s OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in paragraph 244, but could be excluded by the presently proposed language. If an out-of-step blocking phrase is inserted in Requirement R1 of the standard, the emphasis should be modified to read something like: “. . . , and its out-of-step blocking schemes must allow tripping for fault conditions.” This standard should also require that out-of-step blocking settings coordinate with both the loadability and protection characteristics. The out-of-step blocking references would seem to fit best within the organization of the standard if included as a new Requirement R2 (FERC’s paragraph 244 anticipates “. . . an additional Requirement . . .”), with re-numbering of the proposed R2 through R5 as R3 through R6. The essential content of the DT’s proposed phrase in R1 would be included as part of this new R2, which would read something like:R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate its out-of-step blocking schemes to ensure that both: R2.1. Out-of-step blocking schemes allow tripping for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. R2.2. Relay out-of-step blocking settings coordinate with both the relay loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings. The Measure for this proposed R2 would read something like:M2.The Transmission Owner, Generator Owner, and Distribution Provider with out-of-step blocking schemes shall have evidence such as spreadsheets or

Organization	Yes or No	Question 2 Comment
		summaries of calculations to show that each of its out-of-step blocking schemes is set to comply with the requirements of R2.1 and R2.2. The VSL for R1 would not change; specifically it would not reference out-of-step blocking schemes. The VSL for this proposed new R2 would be "Severe" and read something like:A Transmission Owner, Generator Owner, or Distribution Provider did not allow its out-of-step blocking schemes to trip for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. ORA Transmission Owner, Generator Owner, or Distribution Provider did not coordinate operation of its out-of-step blocking schemes with both the relay loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings.
Independent Electricity System Operator	No	We agree with the inclusion of Section 2 of Attachment A in the Requirement Section but the proposed modification may not fully meet the directive that the additional requirement is assigned a VRF and VSL. This may require the creation of a separate main requirement rather than simply including the condition as a part of a requirement.
Southern California Edison	No	Requirement R1.7, R1.8, R1.13 do not provide a clear guideline on generators connected to the load center on Radial basis, where load current into the generators (forward direction current seen by the relay) is just an auxiliary load and insignificant compared to the transmission line rating.
ISO New England Inc.	No	Requirement R1, Parts 7, 8 and 9:Requirement R1, Parts 7, 8 and 9, replace the phrase "under any system configuration" with "under any system condition:" 7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any systemcondition.8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any systemcondition.9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the [___] to the under any system condition. [Brackets added, also see further comment on missing wording following]This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern.Requirement 1, part 9:As currently written, Requirement 1, part 9 states:9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is

Organization	Yes or No	Question 2 Comment
		necessary in order for this sentence to make any sense.
Long Island Power Authority	No	Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. Requirement 1, part 9:As currently written, Requirement 1, part 9 states:9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
ITC Holdings	No	The proposed wording seems out of place in this requirement and is not clear as how it is being applied to subrequirements 1 - 13
NPPD	Yes	I'm ok with that. It could have easily been left in Attachment A. You didn't bring the other language from attachment A to R1. You could of created a separate requirement for OOS, but I'm fine with moving it to R1.
FirstEnergy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
American Transmission Company	Yes	
Southern Company	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
Ameren	Yes	
American Electric Power	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

3. Requirement R1, setting 10 has been modified to address the directive in Paragraph 203 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

Summary Consideration:

Many commenters were concerned about the coordination with the relay loadability requirements of R1 – criterion 1.10 with the transformer damage curve as expressed in IEEE C37.91 Figure A4, which defines transformer through-fault withstand capability as starting at twice the nominal nameplate rating; R1, criterion 1.10 requires that loadability be 150% of the maximum nameplate (which itself is often 1.66 times the nominal nameplate – resulting in loadability of over 2.5 times the nominal nameplate rating).

IEEE C37.91 Figure A5 has two components to the thermal damage curve for through-faults: the "thermal component" begins at 2x the transformer nominal nameplate rating, and seems to be the root of commenters' concerns. The "mechanical component" begins at a current equal to the reciprocal of the twice the transformer impedance. The commenters are correct in their characterization of the "thermal component" of the transformer damage curve, in that it is not possible to satisfy the posted PRC-023-2 R1, criterion 10 and also protect the transformer for currents in this region. Upon careful consideration of FERC Order 733, the SDT revised R1 criterion 10 to reference only the mechanical withstand capability.

Many commenters questioned the inclusion of "limiting piece of equipment" rather than "transformer", as the fault withstand capability of terminal equipment (switches, breakers, current transformers, etc) may be unavailable. Upon further consideration of FERC Order 733, the SDT modified criterion 10 by replacing "limiting equipment" with "transformer."

Organization	Yes or No	Question 3 Comment
Pepco Holdings, Inc - Affiliates	No	It would appear that this requirement has already been addressed in the R1 introductory paragraph by the phrase "...while maintaining reliable protection of the BES for all fault conditions." How could one "maintain reliable protection of the BES" if relays are set with operating times that result in equipment being exposed to fault levels and durations that exceed their capability. This introductory requirement to provide reliable fault protection applies to all sub requirements not just to section 10 (old R1.10). As such, the added language in section 10 seems redundant and superfluous. Secondly, if the proposed language were to remain in section 10, why is the term "limiting piece of equipment" used and not just "transformer"? It appears the major concerns related to the comments contained in Order 733 were around exceeding transformer fault level/duration limitations. If that is the concern, why not just use the phrase "do not expose the transformer to fault levels and durations that exceeds its capability"
Bonneville Power Administration	No	In some cases, Section 10 of Requirement R1 would be impossible to meet. For example, a 150/200/250 MVA, OA/FOA1/FOA2 transformer is required by Section 10 to have its protection set so that it doesn't operate at or below 150% of the maximum transformer rating of 250MVA, or 1.5x250=375MVA. The modified Section 10 would also require that the protection not expose the transformer to a fault level and duration that

Organization	Yes or No	Question 3 Comment
		exceeds its capability. According to IEEE C37.91, a through-fault of two times the transformers base rating, 2x150=300MVA, will be damaging to the transformer. For this particular transformer, which is not unusual, Requirement R1, Section 10, requires the protection to operate for through faults of 300MVA or greater, but not operate for loads of 375MVA or less. It is impossible to simultaneously meet both of these conditions, so Section 10 is unacceptable. One possible way to correct the problem is to change the requirement so that the protection does not operate below 200% of the transformer base rating. This would allow the protection to meet IEEE C37.91 for through-faults and still allow overloading of the transformer.
FirstEnergy	No	Although it is true that the FERC directive specifically states "limiting piece of equipment" their reasons and justifications all involve transformers. We propose replacing "limiting piece of equipment" with "transformer" would meet the FERC's reliability concern as well as provide clarity to applicable entities. We believe this is an equally effective means of meeting the directive.
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others. Additionally, we question if this directive should be addressed in the FAC standards rather than in PRC-023.
MRO's NERC Standards Review Subcommittee	No	The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least one second
Dominion Electric Market Policy	No	The requirement is not clear. For example, how do we determine and verify the limiting piece of equipment under fault conditions? It might be a splice or a jumper. Since the document refers to duration, this seems to apply mainly to transformer overcurrent relaying which would be for overload protection not fault protection that has no intentional delay.
E.ON U.S. LLC	No	E.ON U.S. is concerned that the proposal requires a fault protection scheme separate from the phase overload relays. With the phase overload relays set at 150% of the maximum transformer nameplate, they (by themselves) will not be able to coordinate with the transformer damage curve (as defined by IEEE) for low level faults.R1, Section 10 meets the directive of Paragraph 203; however it is not clear that Section 10 only applies when there is no high side breaker at the transformer, as discussed in Order No. 733. E.ON U.S. recommends that an exclusion of the transmission line relay settings should be considered when transformer overload protection is provided by other means (i.e. A low side breaker trip or a direct transfer trip of the remote breaker initiated by an overload relay installed on the transformer).

Organization	Yes or No	Question 3 Comment
NPPD	No	Setting the relay to 150% of a 336MVA or 500MVA transformer can force you to cross the transformer damage curve and now your transformer is at risk to loss of life.
Idaho Power - System Protection	No	The reworded Requirement should to be clarified. The fault level and duration that the limiting element will be exposed can be a function of fault location and contingencies, such as relay failures, that are not addressed or defined. No measure is specified in the reliability standard that will demonstrate compliance with the revised requirements in R1.10.
Kansas City Power & Light	No	Although setting #10 includes language to protect the most limiting element for a transmission circuit ending with a transformer, the relay settings in the bulleted items are absent any consideration for other elements such as disconnect switches, wave traps, current transformers, potential transformers, etc. and are only with concern to the transformer. The relay settings should consider the fault current capabilities of all the facilities involved and be set in magnitude and duration of the lowest facility rating.
Ameren	No	The language is not clear. It appears that the transmission line relays are being used as the thermal overload protection for the transformer.
ITC Holdings	No	R1 -10 is all about loadability of the relays protecting the transformer. If the requirements of R1-10 cannot be met without exceeding the transformer damage curve, then we go to R1-11. We do not feel that there should be anything to do with fault duty.
Duke Energy	No	R1.10 has added the requirement that protection settings can't expose transformers to fault levels and durations that exceeds its capability, while at the same time not operate at or below 115% of highest emergency rating. We would argue that an overcurrent relay cannot be set to satisfy both requirements. A transformer's through-fault protection curve (C37.91) begins at 200% of the transformers self-cooled rating. The highest emergency rating is commonly 150% (or higher) of the transformer's highest (cooled) rating. Overcurrent relays could not be set to coordinate with both the damage curve and the overload rating.
South Carolina Electric and Gas	No	This requirement needs to be refined to clearly state the intent. It is unclear if "limiting piece of equipment" is referring to just transformers or other elements. Some of the elements involved in the construction of a transmission line/transformer arrangement such as line conductors, etc. may not have published fault current ratings. It is unclear how to determine the most limiting piece of equipment if published fault current ratings are not available for these devices
American Transmission	Yes	The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least

Organization	Yes or No	Question 3 Comment
Company		one second.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
Long Island Power Authority	Yes	
American Electric Power	Yes	
	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

4. **Requirement R3 has been added to address the directive in Paragraph 186 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

The SDT modified the wording of R4 as follows. "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide....” as a result of comments.

The SDT agreed to remove the Regional Entity from the list of entities receiving this information in Requirement R4.

Comments indicated that all relay setting limitations should be included in the Facility Rating per FAC-008. The operator will then be made aware of any and all relay limitations through the use of those ratings (FAC-009). FERC Order 733 paragraph 186 requires an additional notification of relay setting limitations specifically for relay settings that are set based upon the 15 minute criteria. This is being done to ensure that transmission operators have knowledge of which facilities have relays set using a 15 minute criteria and which facilities have relays set using a 4-hour criteria. The SDT believes that requiring periodic submittals of this information will help create a clear and less ambiguous requirement and improve measurability which should aid applicable entities in compliance and result in more uniform enforcement actions.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration		This change adds an additional burden to the applicable entities, but serves no purpose other than to satisfy FERC’s misinterpretation of what a fifteen-minute facility rating is.
ERCOT ISO		The entities who receive the list of facilities should be the same from R3 to R4.
Northeast Power Coordinating Council	No	Referring to the response to Question 2 above, “Setting” should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
Pepco Holdings, Inc - Affiliates	No	To avoid confusion, the wording of R3 should be revised as follows: “Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 Setting 2 as the basis for verifying transmission line relay loadability shall provide....” The problem with the SDT’s proposed wording of R3 is that suppose a TO chose to utilize R1 Setting 1 criteria (> 150% of 4 hr rating) as their basis for verifying loadability, but the actual relay setting also satisfied criteria R1 Setting 2 (> 115% of 15 min rating) the entity may interpret that they are still obligated to forward the list since the relay settings also satisfied R1 Setting 2 criteria
FirstEnergy	No	We suggest removing the Regional Entity from the list of entities receiving this information since they do not have a reliability-related need for it.

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	No	We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don't inadvertently cause a relay operation due to loading.
TSGT System Planning Group	No	We think that the data needs to be given only to the Transmission Operators, which is what FERC Order No. 733 requires. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using Requirement 1, Setting 2 for setting a phase protective relay that is used to protect an applicable facility. There is no need for periodic duplicate submittals.
Kansas City Power & Light	No	Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	The proposed revision goes beyond what's asked for in the directive as it requires the responsible entities to provide the list to entities other than the TOP. The directive asks for providing the list to the TOP only.
Southern California Edison	No	The relay if set according to Requirement R1.2 are based upon 15 minute highest seasonal facility loading duration. This gives sufficient time for the operators to take manual corrective action, if the deem so. There is no need for the Registered entity to provide a list, as it would not be efficient and cost effective.

Organization	Yes or No	Question 4 Comment
ISO New England Inc.	No	We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don't inadvertently cause a relay operation due to loading.
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
E.ON U.S. LLC	Yes	
Arizona Public Service Company	Yes	
American Transmission Company	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	

Organization	Yes or No	Question 4 Comment
ComEd	Yes	
Manitoba Hydro	Yes	
Long Island Power Authority	Yes	
Ameren	Yes	
American Electric Power	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

5. Requirement R4 has been added to address the directive in Paragraph 224 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

Summary Consideration:

The FERC Order "direct(s) the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12."

Since the data is subject to audit, the SDT interprets this to mean that the ERO must gather and have continuously available a list of facilities using Requirement R1 criterion 12. The SDT therefore interprets the "by request" nature of the directive to indicate the way the ERO makes the list available to users, owners and operators of the Bulk-Power System, not how the ERO gathers the data from TOs, GOs and DOs.

As suggested by one of the comments, the SDT intended for registered entities to provide this data to their Regional Entities who would in turn provide it to the ERO. Although some comments have suggested other ways to accomplish this, the majority of responders appear to agree with the SDT proposed method.

Organization	Yes or No	Question 5 Comment
ERCOT ISO		The entities who receive the list of facilities should be the same from R3 to R4.
Northeast Power Coordinating Council	No	R4 addresses the directive, but as commented on previously, "Setting" should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
IRC Standards Review Committee	No	The objective of R4 as written is unclear and does not conform with the results-based concept in that it does not clearly specify a reliability directive. We suggest removing this requirement altogether as we do not believe this should be an on-going enforceable requirement. Rather, we think it makes more sense for NERC to use section 1600 of its Rules of Procedure to request the data. We believe that NERC and the Commission will likely determine that they don't need to continually receive this data after reviewing it the first time. Nothing in the directive indicates this must be accomplished through a standard. If NERC and FERC do identify a continuing need for the data, the standard could be modified at a later date.
MRO's NERC Standards Review Subcommittee	No	While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.

Organization	Yes or No	Question 5 Comment
Arizona Public Service Company	No	FERC Order required the list to be made available for review to users, owners and operators of the Bulk-Power System upon request. Requirement 4 does not include the "request" requirement, implying that the Registered Entity must provide the list without a request. Further, the requirement does not specify what the Regional Entity will do with the list once it is provided.
TSGT System Planning Group	No	FERC Order No. 733 requires the settings be provided upon request and no initial or periodic submittal is required.
Kansas City Power & Light	No	The proposed R4 exceeds the concerns of FERC in this matter. FERC directed a requirement to provide information upon request. The proposed R4 requires data submission without request of the parties with interest to the information. Recommend the SDT consider modifying this requirement to provide this information upon the request of appropriate operating parties.Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	The objective of R4 as written is unclear. We speculate that by requiring the TOs, GOs and DPs to provide the list (associated with R1, Section 12) to the REs, the ERO will collect the relevant information from all REs to facilitate provision of such information to owners, users and operators of the BES upon request. If this is the intent, we suggest to replace “REs” with “ERO” to make it a more direct and efficient way to provide the information needed to support the request for information process.The requirement as written does not conform with the results-based concept in that it does not clearly specify a reliability directive. Hence alternatively, we suggest removal of this requirement altogether since the directive asks the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities. This can be dealt with outside of the standard process, for example, through RoP 1600.

Organization	Yes or No	Question 5 Comment
Long Island Power Authority	No	FERC order 733 p224 requires that the list of facilities that have protective relays set pursuant to R1.12 of anticipated overload be made available to users, owners, and operators of the BPS. However, the proposed revision to R4 requires the list to be made available to Regional Entity only. Please clarify. Also, FERC order uses the term “by request” which is missing from the proposed revision.
American Transmission Company	Yes	While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.
Pepco Holdings, Inc - Affiliates	Yes	
FirstEnergy	Yes	
Dominion Electric Market Policy	Yes	
E.ON U.S. LLC	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	

Organization	Yes or No	Question 5 Comment
American Electric Power	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	Paragraph 224 addresses R1.12, requiring documentation and making available a list of facilities that have protective relays set pursuant to R1.12. Although Order 733 was silent on R1.13, should the new R4 not also apply to R1.13?
Wisconsin Electric		No comment

6. **Requirement R5 and part 5.1 (previously Requirement R3 and part 3.1) have been modified to establish the framework to address the directive in Paragraph 69 of Order no. 733, although the criteria itself (which will be Attachment B) is still being developed. Do you agree that this is an acceptable and effective method of meeting this directive considering that Requirement R5 is establishing the construct to insert the criteria at a future time in the form of Attachment B? If not, please explain.**

Summary Consideration:

A majority of commenters do not believe, or were unable to determine whether, the construct established in Requirement R5 is an acceptable and effective method of meeting this directive. Almost all commenters, regardless of whether they responded "Yes" or "No," indicated their responses are conditional pending review of the criteria. The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were posted on September 23 for a 20-day informal comment period. The SDT has reviewed Requirement R5 and the criteria in Attachment B and has made conforming changes to ensure no conflicts exist. The full standard with Attachment B will be posted for a 45-day formal comment period.

One commenter disagreed with the approach in Requirement R5, part R5.1, noting there are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The commenter observed it is not necessary to dictate additional criteria because the TPL standards already require extensive studies of the transmission system. The SDT believes the proposed criteria defining the test Planning Coordinators will use to determine which facilities must comply with PRC-023 will address the commenters concerns. The proposed criteria are consistent with the simulations and assessments required by the TPL Reliability Standards and allow the Planning Coordinators to utilize those assessments as directed in Order No. 733.

One commenter noted that the SDT needs to work closely with the Reliability Coordination SDT (Project 2006-06) which is tasked with defining critical facilities or indentifying criteria for developing a list of critical facilities. The commenter disagreed with use of the phrase "facilities that are critical" in this requirement and cautioned that a requirement to create a list of critical facilities should not be addressed in this standard. The SDT notes that although the phrase "critical to reliability of bulk electric system" appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase "critical to reliability of the Bulk Electric System" in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

Some commenters noted that Requirement R5, Part 5.3 should require that the Planning Coordinator provide its list of facilities to all Transmission Owners, Generator Owners, and Distribution Providers within its area; not only the entities with facilities on the list. The SDT believes this is consistent with the intent of the requirement and has modified the standard accordingly to make this requirement explicit.

One commenter noted that Requirement R5, Part 5.1 is unnecessary since the process to use the criteria in Attachment B would almost certainly be to simply apply the criteria and that requiring documentation of such a process will result in increased paperwork and additional preparation for an audit without a reliability benefit. The SDT agrees that this part of Requirement R5 is unnecessary and has removed it from the Standard.

Several commenters requested modifications that are outside the scope of the SAR for this project.

- Two commenters indicated Requirement R5 should include wording that limits the scope of the transmission facilities to be evaluated to only those that can be tripped by the relay settings subject to Requirement R1 and that the SDT should add a requirement that the Transmission Owners, Generator Owners, and Distribution Providers provide the Planning Coordinators with a list of such transmission facilities. The SDT believes that since the existing Requirement R3 does not restrict the facilities which the Planning Coordinator must consider, the proposed modifications are outside the scope of the SAR for this project. The SDT further believes that transmission facilities that have no phase protective relays subject to tripping on load are sufficiently uncommon that the proposed requirement would place a significant burden on Transmission Owners, Generator Owners, and Distribution Providers while providing limited benefit to the Planning Coordinators.
- Two commenters believe the standard should not be applicable to Distribution Providers. The SDT believes that since the approved PRC-023-1 includes Distribution Providers, the proposal to exclude Distribution Providers is outside the scope of the SAR for this project. However, the SDT further believes it is possible for a Distribution Provider to own a relay that protects a transmission facility, even if the Distribution Provider does not own the protected facility.
- One commenter observed there is much confusion about the registration of Planning Coordinators and suggests that while the Order proposes the Planning Coordinator perform this test, it could be assigned to the Regional Entity or the Reliability Coordinator (as in the SPCTF recommendation) and achieve the same result. The SDT notes the approved PRC-023-1 already assigns the Planning Coordinator with the requirement to determine which facilities must comply with PRC-023. The SDT believes there is no reason to revisit this issue.

One commenter believes it is not appropriate to modify Requirement R5, part 5.3 to include the Regional Entity as a recipient of the list of transmission facilities because the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. The SDT believes the role of the Regional Entity in compliance enforcement does not preclude a Reliability Standard from including Regional Entities as the recipients of data. The SDT further believes that providing the Regional Entity with the list of transmission facilities subject to Requirement R1 is the most direct way to address the Commission's objective to aid in the overall coordination of planning and operational studies among Planning Coordinators, Transmission Owners, Generator Owners, Distribution Providers, and Regional Entities.

Two commenters believe the criteria in Attachment B along with any necessary modifications to the associated requirement should be developed by a full drafting team. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were developed with the assistance of a "Blue Ribbon Panel" comprised of members from each region who are Subject Matter Experts in the area of Transmission Planning. Order No. 733 directs that the criteria in PRC-023 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards, and input from the Blue Ribbon Panel provides additional expertise necessary to develop the directed modifications.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	Requirement R5 states that the Planning Coordinator will determine which facilities below 200kV are critical to the reliability of the Bulk Electric System by applying criteria defined in Attachment B, which is to be developed. Therefore, respondents cannot comment on Attachment B. Respondents reserve the right to

Organization	Yes or No	Question 6 Comment
		comment when Attachment B is available for review. Because the document has been presented to the industry without Attachment B, how will Attachment B be presented to the industry? Regarding sub-requirement 5.3, it must be revised to clarify that the Planning Coordinator will provide the list of facilities subject to the Standard to all of the TOs, GOs, and DPs registered in its footprint, not just to those entities that have facilities on the list.5.2 refers to “Part 1”. As commented on previously in Question 5 and elsewhere, Part or Sub-requirement should be used for consistency.
Bonneville Power Administration	No	Requirement R5 is okay, but Part 5.1 adds an additional and useless extra burden to the applicable entities. The process that the Planning Coordinator is required by this part to have would almost certainly be to simply apply the criteria in Attachment B to lines and transformers operated below 200kV to determine if they are critical to the BES. Requiring documentation for such a trivial process results in increased paper work, additional preparation for an audit, and is a waste of everyone’s time. We suggest deleting Part 5.1.
IRC Standards Review Committee	No	We disagree with modifying the requirement until the criteria is identified. Modifying the requirement now presumes the criteria will have no impact to the requirement. Contrarily, we believe that the criteria may cause some change to the requirement as well. The criteria in Attachment B along with any necessary modifications to the associated requirement should be developed by a full standards drafting team. Only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others.
MRO's NERC Standards Review Subcommittee	No	As noted in Q1 above, a response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified faculties below 200 kV.In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are “known” to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
E.ON U.S. LLC	No	See comments for item #1.
Transmission Access Policy Study Group	No	The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. TAPS has been unable to find or think of an example in which a DP would have a load-

Organization	Yes or No	Question 6 Comment
		responsive transmission phase protection system, aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities.If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
American Transmission Company	No	As noted in Q1 above, an affirmative response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are “known” to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
TSGT System Planning Group	No	While we agree that the purpose of Requirement R5 is beneficial, there is much confusion about registration and responsibilities of Planning Coordinators. Though the FERC order proposes that planning coordinators perform the test developed herein, there is also flexibility in how NERC can achieve the same result. We believe that the Regional Entity (or the Reliability Coordinator, as was included in the System Protection and Control Task Force recommendation) should be the responsible functional entity for determining which elements operated at less than 200 kV need to meet Requirement R1. The Region was responsible for determining operationally significant facilities during the “Beyond Zone 3” process.
NV Energy	No	This approach is not yet an acceptable and effective method of meeting the directive of paragraph 69. Whether it becomes an acceptable and effective method of meeting the directive will depend on the content of Attachment B. I’ll reserve specific judgment and concerns until Attachment B is available for comment.
NPPD	No	Attachment B has not even been developed.
Idaho Power - System Protection	No	It is not acceptable or effective until Attachment B is completed and available for review.
Kansas City Power & Light	No	Do not agree with the approach in R5 and R5.1. This proposes to establish the criteria by which Reliability

Organization	Yes or No	Question 6 Comment
		Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria.In addition, in R5.3, do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	We are unable to assess its acceptability and effectiveness until Attachment B is developed.
Utility Services	No	The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. We have been unable to find or think of an example in which a DP would have a load-responsive transmission phase protection system , aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities.If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
Long Island Power Authority	No	LIPA understands the drafting team’s rationale, however, believes that the proposed method in Attachment B

Organization	Yes or No	Question 6 Comment
		should be developed before providing comments.
Ameren	No	See our response to Question 1
American Electric Power	No	Please refer to our comment under question number 1. AEP reserves the right to provide additional comments once Attachment B has been drafted and supplied for industry review.
ERCOT ISO	No	ERCOT ISO respectfully asserts that the changes in this standard need more thorough discussion. This standard is incomplete without the Attachment B and the intent of the requirements is not explicitly clear. A standard drafting team (not a SAR SDT) needs to develop Attachment B through discussion of the entire process that will meet Order 733 directives. Attachment B is a critical component needed to assess R5 and provide further feedback. Requirement 5 needs to be reworded for clarity. The standard drafting team assigned to this project needs to work closely with the Reliability Coordination SDT (Project 2006-06), which is tasked with defining critical facilities or identifying criteria for developing a list of critical facilities.ERCOT ISO disagrees with the use of the phrase ‘facilities that are critical’ in this requirement. A requirement to create a list of critical facilities should not be addressed in this standard.
Duke Energy	No	We don’t have Attachment B yet, and the standard development timeline has the standard being submitted to FERC in March of 2011, which we believe is an unreasonable timeline.
Pepco Holdings, Inc - Affiliates	Yes	While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology contained in Attachment B once it is developed.
FirstEnergy	Yes	Although we agree that R5 is the appropriate requirement to reference the criteria to be used, it is still to be determined if we agree with the criteria since it is still being developed.
Consumers Energy	Yes	We are concerned about the criteria still undergoing development, and will offer any relevant comments on that criteria when it is published.
Arizona Public Service Company	Yes	
Dominion Electric Market Policy	Yes	

Organization	Yes or No	Question 6 Comment
PacifiCorp	Yes	
Southern Company	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

7. **Attachment A has been modified to address the directive in Paragraph 264 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

Three-fourths of commenters believe the addition of section 1.6 in Attachment A is not an acceptable and effective method of meeting this directive. More than one-half of commenters believe that addressing the directive in the proposed manner will have a negative impact on reliability of the bulk electric system. The SDT agrees that addressing the directive in the manner proposed in the first posting will have the unintended consequence of impacting the dependability and security of certain protection systems. The SDT has revised the draft standard to address the following concerns noted by commenters.

- More than one-half of commenters noted that the proposed modification would require overcurrent fault detectors applied to supervise distance (impedance) elements to meet the relay loadability requirements which would have a detrimental impact on reliability. Setting these fault detectors to meet PRC-023 would restrict the ability of some distance elements to trip for end-of-zone faults, particularly on weak source systems. Eliminating the fault detector to avoid this concern would have the negative impact of making the protection system susceptible to undesired tripping during close-in faults on adjacent elements. Some commenters further noted that many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled.
- Several commenters noted that the standard should apply to protective systems and not to individual components of protective systems and that compliance should be based on the ability of the protective system as a whole to meet the performance criteria established by the standard. Some commenters also noted that a clarification is required that “protective functions” applies only to those protective relay elements that would respond to non-fault or load conditions and could issue a direct trip.
- Some commenters noted their belief that the modification goes well beyond the Commission’s concern and they proposed alternatives they believe would be equally effective and efficient approaches to addressing the Commission’s reliability concerns.

In response to these concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to include “1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications.” The SDT also modified the second bulleted item in section 2.1 to add the clause, “except as noted in section 1.6 above.”

Some commenters expressed concern that the proposed modifications would require the overcurrent element in a switch-on-to-fault (SOTF) scheme to be subject to the relay loadability criteria, in conflict with the SPCTF technical paper that indicates there is no suggested loadability criterion if the voltage arming threshold is set low enough. Some commenters expressed concern that the proposed modification could negatively jeopardize reliability by resulting in an operational decision to open breakers upon loss-of-potential to a protection system. These commenters note that it would be preferable to leave the element in-service with fast tripping enabled for a fault until the loss-of-potential condition can be diagnosed and corrected. The SDT believes that the modifications to section 1.6 noted above remove the unintended consequence of the original modifications that could have required overcurrent functions in all SOTF schemes and overcurrent functions used to supervise distance elements to meet Requirement R1.

One commenter proposed that the requirement for setting supervising relays be 115 percent of the facility rating nearest to a 4-hour duration rather than the 150 percent threshold established for other phase protective relay settings that may limit transmission system loadability. The SDT believes that with the modifications to section 1.6 noted above the same setting requirements are appropriate for all protective functions listed under section 1 of Attachment A. The SDT believes this is appropriate and necessary to meet the reliability objective of this standard.

One commenter noted that this directive needs to be addressed by a full standard drafting team to adequately address this directive and identify equally effective alternatives to the Commission's directives. Another commenter recommended that the NERC System Protection and Control Subcommittee (SPCS) be engaged to investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process. The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.

Organization	Yes or No	Question 7 Comment
Pepco Holdings, Inc - Affiliates	No	We do not agree with the proposed wording of Section 1.6 of Attachment A which makes the standard apply to "Protective functions that supervise operation of other protective functions in 1.1 through 1.5". The standard should apply to "protective systems" not individual components of protective systems. Compliance should be based on the ability of the "protective system" as a whole to meet the performance criteria established by the standard. Delving into the details of individual scheme designs and supervising element operation goes well beyond the purpose and scope of this standard.In paragraph 251 of Order 733 the Commission "expressed concern that section 3.1 could be interpreted to exclude certain protection systems that use communications to compare current quantities and directions at both ends of a transmission line, such as pilot wire protection or current differential protection systems supervised by fault detector relays" and requested comment on "whether it should direct the ERO to modify section 3.1 to clarify that it does not exclude from the requirements of PRC-023-1 pilot wire protection or current differential protection systems supervised by fault detector relays." The Commission reiterated again in paragraphs 266, 268, and 270 their concern with not including supervising elements associated with "current differential schemes" to prevent them for operating on loss of communications. That being said, the proposed revision to Attachment A to include supervising elements for all protective functions in 1.1 through 1.5 goes well beyond addressing the Commission's concern. We believe the Commission's concern could be addressed by simply modifying Attachment A by deleting proposed section 1.6 and adding a new section 1.5.5 "Line current differential schemes, including supervising overcurrent elements". The SDT's current proposed wording for Section 1.6 would require the overcurrent element in a switch-on-to-fault scheme to be subject to the loadability criteria. However, the NERC SPCTF in their June 7, 2006 technical paper "Switch-on-to-Fault Schemes in the Context

Organization	Yes or No	Question 7 Comment
		of Line Relay Loadability" indicated there is no suggested loadability criterion if the voltage arming threshold is set low enough. Similarly, fault detectors which supervise distance elements would be subject to the loadability standard. However, there are no criteria established on how to set these elements, particularly on weak source systems, or zone 3 applications, where in order to reliably detect faults at the end of the zone of protection may require setting the supervising fault detector below 150% of line rating. The NERC SPCTF in their June 7, 2006 technical paper "Methods to Increase Line Relay Loadability" provided recommendations to increase loadability of distance elements through various techniques, such as the use of load encroachment elements or blinders, but does not specifically address setting of supervising elements. In fact, at present, there is no reliability standard requiring the use of supervising elements, and some newer microprocessor relays do not even employ supervising fault detectors on their distance elements. FERC in their Order 733 stated "As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding the exclusion of supervising relay elements. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns."In summary, we believe that addressing the Commission's concern regarding supervising elements on current differential schemes, as described in our second paragraph above, would satisfy the intent of Order 733, while not imposing unnecessary additional restrictions on what has proven historically to be extremely reliable protection practices.
PSEG Companies	No	In attachment A was added a new requirement, item 1.6. We not agree with this. Sometimes these elements have to be set lower than the criteria. As long as the protection system as a whole does not trip the line, then that should meet the criteria. Individual elements that supervise tripping element should NOT be part of the standard.
Bonneville Power Administration	No	Here we have a situation where the standard is being compromised to satisfy FERC's misunderstanding of what a supervising relay is. In Paragraph 266, FERC gives an example of how a line differential relay works in an attempt to demonstrate why supervisory elements must not operate for load, but instead they clearly demonstrate their misunderstanding of the details of differential relay operation and what a supervisory relay is. Modern differential relays will disable the differential function upon loss of communications. If an overcurrent element is present, it would be used for backup protection, not as a supervisory element. If an overcurrent element were used to supervise a differential element, the sensitivity of the differential relay would be lost and the result would be a simple overcurrent relay. FERC's misunderstanding has resulted in the improper addition of supervisory relays in Attachment A, Section 1. Sometimes supervisory relays must be set below maximum loading to obtain the purpose they were intended for. For example, it is often necessary to set overcurrent supervision of distance relays below the maximum load current of the line so that they will operate for remote faults. This modification to Attachment A would prohibit that action and make it impossible to set the supervisory relays to comply with the standard and still provide adequate protection. The

Organization	Yes or No	Question 7 Comment
		modification to Attachment A is unacceptable.
FirstEnergy	No	FirstEnergy supports applying PRC-023 to certain supervising relays, such as overcurrent relays that are enabled only when another (usually communications based) scheme is out of service, or overcurrent relays that are ANDed with current differential elements that can trip by themselves if the communications path used by the current differential scheme is compromised. However, it is not clear that a 150% factor is the correct one to use in this case. Our understanding is that 150% is a combination of an error factor (widely utilized by industry) of 15% plus a 35% margin to approximate a 15 minute interval rating to give operators time to react to adverse system conditions. It is unclear that this extra 35% margin is needed for these supervising relays, when the reliability goal is to prevent relays being continuously picked-up. We recommend that the standard utilize a 115% margin (rating duration nearest 4 hours) for these types of supervising relays and that this would be adequate to meet the Commission's stated reliability concerns.However, there are several other types of schemes that utilize supervising relays where applying PRC-023 would be detrimental to the reliability of the bulk power system. One widely used case is the supervision of an impedance relay when there is no communications scheme involved. There are cases where an impedance element/relay which is set per PRC-023, correctly operates for a fault it is intended to see, but that the actual current value will be on the order of the line rating, which will result in the scheme not operating if the supervising relay is set as the commission proposes. The alternative for these types of schemes is to remove the supervision from the scheme, which will result in the scheme operating purely on the impedance element, which is exactly the reliability concern that the Commission is trying to address with this directive. However, many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled, adding to the complexity of the issue. Since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission's directive.
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
MRO's NERC Standards Review Subcommittee	No	In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed).Historically, protection engineers have been biased toward dependability to ensure the safety of people and equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the

Organization	Yes or No	Question 7 Comment
		dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Dominion Electric Market Policy	No	Dominion disagrees with the directive to the ERO to revise section1 to include supervising relays for example, the fault detectors that we have in electromechanical distance schemes. The impedance relays are set to meet Reliability Standard PRC-023-1 while the overcurrent fault detector does not trip the transmission line breaker(s) independently of the impedance relays. Simultaneously meeting full allowance of the line terminal emergency loading limit and providing adequate sensitivity for detecting line faults with this fault detector will simply not be achievable for many of our lines.
E.ON U.S. LLC	No	E.ON U.S. requests a clarification of “protective functions” such that it applies only to those protective relay elements that would respond to non-fault or load conditions, and could issue a direct trip, upon operation, during a loss of communication or loss of potential condition.
American Transmission Company	No	In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed).Historically, protection engineers have been biased toward dependability to ensure the safety of people and equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected
PacifiCorp	No	Paragraph No. 264 directs a revision to Section 1 of Attachment A in order to include supervising relay elements. This change as currently written requires further clarification to meet this directive. For example, a Distance element is commonly supervised by a phase overcurrent element (Fault detector). If this change suggests that the overcurrent element has to be set above maximum load, then PacifiCorp disagrees with the modification. The fault detector will not trip the line by itself; it operates to qualify the distance element assertion. It is our standard practice to set this element above load where possible, but without restricting the reach of the distance element. This means that if the fault current at the maximum reach of the distance element is below load, setting the fault detector above load will restrict the reach of the distance element- this would compromise the protection scheme. In microprocessor relays where Load encroachment is used this is even more critical. The Load encroachment function will prevent the distance element from operating in the

Organization	Yes or No	Question 7 Comment
		load region and a fault detector setting that is sensitive enough can be used safely without the need to set it above load current to enhance the distance element reach.
Southern Company	No	The language that has been added to PRC-023 related to the inclusion of protection elements (fault detectors) supervising protection functions that are subject to the PRC-023-2 requirements is not appropriate and will likely decrease the reliability of the BES for the following reasons:- The tripping logic utilizing these elements is an AND function, it takes distance element AND the fault detector (FD) to trip. Since all distance elements meet the loadability criteria, it is not necessary to also ensure FD meet hese requirements.- Setting FD above nominal load point would unnecessarily reduce sensitivity of distance element and in many cases eliminate the distance element's ability to protect the very system element it is designed and intended to protect- It would require very expensive communications based relay schemes to replicate this lost protection if it is even possible to do so; a long radial line is one instance where it would not be possible- Eliminating the FD would actually reduce Security and Dependability in electromechanical schemes- There is a whole generation of microprocessor based relays that it is not possible to eliminate the FD; to effectively take it out of service, one would have to set it to the most sensitive setting which would violate the loadability criteria- Relays at terminals with high SIR, a weak source system, and line with large conductors where the far end fault current may be smaller than maximum line current (similar to Exception 6 of the Relay Loadability Exceptions: Determination and Applications of Practical Relaying Loadability Ratings, Version 1.1 published November 2004 by the System Protection and Control Task Force of NERC)- Faults with low power factor could present a similar magnitude of line current as normal high power factor load currents
NPPD	No	Please remove Attachment A, R1.6. "Protective functions that supervise operation of other protection functions in 1.1 through 1.5.". If you do not remove R1.6 you must provide a detailed explanation of what supervise operation means and give examples. Utilities have thousands of relays that have imbedded fault detective supervision overcurrents for phase distance elements that are set at 0.5 amps or some similar value. This can not be changed. From your requirement these utilities would have to replace all of these relays or we would have to lower the Facality rating to 0.5 amp secondary/150%. You are also stating that if we have an external phase overcurrent fault detector that supervises a phase distance relay that this fault detector must now have to meet Requirement 1. This is an unacceptable requirement if this is your intent. You are putting the system at risk if this is your intent. We must set our relays to protect the line. We must also set fault detectors to pickup for all faults considering N-1 conditions at a minimum where the strongest source must be remove and the relays must still clear the fault. Please do not lose focus of the purpose: "Protective relay settings shall be set to reliably detect all fault conditions and protect the electrical network from these faults". If you have questions on my comments feel free to contact me. Steve Wadas, NPPD, 402 563 5917 Wk.

Organization	Yes or No	Question 7 Comment
Consumers Energy	No	The supervising elements addressed within this change may fundamentally be unable to be set in accordance with the requirements of PRC-023, while still permitting the Protection System to function properly for fault conditions. The supervising element is usually present to assure that a distance element does not operate inadvertently for close-in zero-voltage faults near the relay location in the non-trip direction, but does not, by itself, produce a trip. We appreciate that NERC must respond to this directive, but believe that the change, as expressed, will be detrimental to reliability.
ComEd	No	1) Certain relay elements may be thought to be “supervising relay elements”, when their function is specific and more limited. A very common example would be a phase overcurrent relay that is required to actuate along with a phase distance relay to cause a trip. In many applications, the phase overcurrent relays function is only to assure that the phase distance relay will not cause a trip when a line is taken out of service and no potential restraint is applied to the phase distance relay. Thus, loadability of the phase overcurrent relay is not a concern. Raising the level of the overcurrent element may negatively impact the fault detecting ability of the two relays. This is perhaps a limited function supervising relay element. It is complementary to the phase distance relay which provides the necessary loadability. 2) Although we don’t employ out of step tripping, it would seem that the argument for the overcurrent element of an out of step tripping scheme would be the same as for the phase distance element. 3) Are there supervisory elements for switch onto fault schemes that could limit loadability? 4) In our experience, relays that supervise overcurrent relays are typically specifically designed to provide loadability in order to allow the overcurrent relay to provide greater sensitivity without worrying about its loadability. Thus this requirement would limit the use of such a scheme. 5) FERC’s main example seems to refer to an old style of current differential relaying scheme that is likely not very widely applied. Most modern current differential schemes use digital communications and will not trip on loss of communications regardless of the settings of any elements that may be considered to be supervisory relay elements. The drafting team should consider modifying 1.6 of Attachment A to clarify and more specifically address the FERC concern. Three suggestions are as follows: 1) 1.6. Protective functions that supervise operation of other protective functions in 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 2) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 3) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5.
Manitoba Hydro	No	Item 1.6 in Attachment A is not necessary. If the protection functions in 1.1 through 1.5 already meet all the

Organization	Yes or No	Question 7 Comment
		loadability requirements, the facility would not trip under heavy load condition by the supervising protection element alone. The directive in paragraph 264 of Order 733 seems to deal with the supervising protection element on the current differential scheme only. It is still arguable whether it is better to allow tripping of the line or restrain from tripping during loss communication and heavy loading condition.
Wisconsin Electric	No	We strongly disagree with this change. Applying the loadability requirement to supervisory functions in protection system will have an extremely negative effect on BES reliability. With this change, protection systems will be less dependable, resulting in increased probability of a failure to detect a system fault. This change should not be implemented.
Long Island Power Authority	No	LIPA believes that the new wording in 1.6 Attachment A is unnecessary since the existing wording already complies with the FERC order p.264. Supervisory functions are already part of the protective functions 1.1 through 1.5. Also, this new wording will be subject to varied interpretation and create more confusion.
Ameren	No	In attachment A - 1.6 is not a tripping function - it's a supervisory function - it in itself does not trip which is the description of '1' therefore needs to be elsewhere if kept.
American Electric Power	No	AEP requests some clarifying information regarding what is envisioned for 1.6 of Attachment A.
ITC Holdings	No	It appears from the new 1.6 (Attachmnt A) that fault detectors must meet loadability requirements. These do not trip and must not be included in PRC023. We will not be able to adequately protect longer lines in weak areas with this requirement in place.
	No	Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
South Carolina Electric and Gas	No	Item 1.6 of Attachment A needs to be clarified. If the intent is to include protective functions such as fault detectors then this could possibly lead to relay sensitivity problems when switching contingencies create weaker systems than normal and a line is faulted. It is unclear why supervisory functions are considered if the protective functions they supervise will operate in compliance with R1
Xcel Energy	No	Xcel Energy disagrees with the inclusion of the supervising functions in part 1.6 of Section 1 in Attachment A. Supervising functions in protection schemes provide security for non-power system fault events and are not the principal elements for scheme operation. Only principal elements should be considered in the requirements of the PRCâ€'023 standard.Functions such as overcurrent fault detectors provide security in the

Organization	Yes or No	Question 7 Comment
		event of a failed potential source or blown secondary fusing. Fault detectors must be set below the minimum end-of-zone fault with a single system contingency in effect. It is common industry practice to set these functions at 60â€‘80% of these minimum fault levels and may necessitate a setting that is below the Facility Rating of a circuit.Increasing the setpoint of an overcurrent fault detector above the Facility Rating will limit the coverage of the protection system and may impact the system’s ability to protect the electrical network from Faults. An alternative is to limit the Facility Rating as allowed in Requirement R1.12. However limiting this Facility Rating places an arbitrary constraint on the circuit and is not justifiable for a non-principal function. Eliminating the fault detector is not possible in the case of some microprocessor-based relays and if it is possible, reduces the security of the protective scheme.
Duke Energy	No	Attachment A has added 1.6 stating “Protective functions that supervise operation of other protective functions” is included in the standard. We would argue that it is not reasonable to include overcurrent fault detectors used to supervise distance elements or breaker failure schemes. These relays provide security to the protection scheme, such as for loss of potential conditions, and do not trip on their own. If these relays would be set per the standard, it would render the schemes ineffective for many fault conditions. In the case of electromechanical schemes, the supervising relay could be removed from service which could make the protection scheme misoperate. In the case of microprocessor relays, the supervising relay is embedded in logic and can’t be removed.
TSGT System Planning Group	Yes	As we interpret the changes to Attachment A they are acceptable. However, there appears to be uncertainty about the intent of the drafting team. We interpret the change to 1.6, in conjunction with 2.1, to allow setting impedance relay fault detector supervisory elements at levels below load current levels. This understanding comes from the realization that the fault detector elements by themselves do not “trip with or without time delay, on load current,” a requirement described in 1. The fault detector elements can cause tripping on their own, but only for conditions of loss of potential or loss of communications, which are both excluded from the loadability requirements as steted in 2.1.If Tri-State’s interpretation of the intent of Attachment A, Sections 1, 1.6, and 2.1 is incorrect, then we do not agree that this is an acceptable and effective method of meeting this directive. There are many protection system locations in our system that require the fault detector supervision elements to be set below load current levels in order for backup impedance relays to operate securely in the event of loss of potential and to operate dependably for remote faults that inherently have low fault current magnitudes.
Idaho Power - System Protection	Yes	The order has been met, but there is significant concern about the inclusion of supervisory elements in protective systems. A supervisory element is not performing a tripping function. As stated in Attachment A “This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:...”. Supervisory elements, used properly, do not trip for load current.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
NV Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
ISO New England Inc.	Yes	

8. **Do you agree that the SDT has addressed the remaining directives: Paragraph 284 to remove the footnote and Paragraph 283 to modify the implementation plan for sub-100 kV facilities (by revising the Effective Date section of the standard)?**

Summary Consideration:

The SDT agrees with several commenters about the proposed language for Effective Dates and has changed the language to the following:

5.1. Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability, the first day of the first calendar quarter 12 months after applicable regulatory approvals.

5.1.2 For supervisory elements as described in Attachment A, section 1.6, the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals.

5.3. Requirements R4 and R5: the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals.

One comment addressed the issue of a reliability standard superseding previous agreements between registered entities and NERC. The SDT believes that, by removing the footnote, the standard does not supersede previous agreements because the latest due date for mitigation of temporary exceptions under the Beyond Zone 3 review was December 31, 2008. Removal of the footnote has no bearing on previous agreements given that all temporary exceptions have expired.

To address the need for entities to meet the requirements of the standard for facilities identified by the Planning Coordinator in the future, the SDT added a new requirement (R7).

Organization	Yes or No	Question 8 Comment
Pepco Holdings, Inc - Affiliates	No	We agree with the removal of the footnote regarding temporary exceptions. However, there appears to be a contradiction between the effective dates for sub 200kV facilities noted in section 5.1.2 (39 months following regulatory approvals) and 5.1.3 (24 months after being notified by its Planning coordinator). If the planning coordinator takes the full 18 months to determine the R5 list (per effective date section 5.2) and the TO has 24 months after that to comply, that would be 42 months following regulatory approval, which is in conflict with the 39 month requirement in 5.1.2. Since the list of sub 200kV facilities may change from year to year, it

Organization	Yes or No	Question 8 Comment
		would seem prudent to make the effective date for those facilities always tied to a defined interval following being notified by the Planning Coordinator and eliminate the 39 month requirement for sub 200kV facilities from 5.1.2. Also, since the Attachment B methodology has not yet been determined, it is unclear how many sub 200kV facilities may fall under these requirements. As such, one cannot yet determine if the proposed 24 months would be sufficient. We propose at least a 36 month interval until the methodology is finalized and the magnitude of the scope better defined. In addition, if supervising elements are included in the standard in some form, an implementation schedule (i.e. appropriate effective dates) need to be developed based on this significant increase in scope and number of facilities to be reviewed.
Bonneville Power Administration		5.1.2 and 5.1.3 both apply to the same systems and should be combined into one sub-requirement. Also, since the date of the applicable regulatory approval is now established, please consider replacing the cryptic phrase “at the beginning of the first calendar quarter 39 months following applicable regulatory approval” with an actual date.
IRC Standards Review Committee	No	While we agree removing the footnote is straight forward and addresses one Commission directive, we believe the other directives need to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directives. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues including a regional entity’s critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
Kansas City Power & Light	No	It is inappropriate for this standard to supersede any other agreements and the provisions of those agreements that have been established between NERC and Registered Entities. The footnote made it clear those agreements would continue to be honored. Recommend the SDT reinstate the principles established by the footnote directly into the Effective Dates section to recognize the authority of those agreements.Agree with the effective dates of 18 months after applicable approvals for R5 and for 24 months after notification by the Planning Coordinator of a new critical facility.
Independent Electricity System Operator	No	We are unable to comment on this in the absence of a proposed implementation plan.
E.ON U.S. LLC	No	Cannot assess the impact until Attachment B is developed and commented sections above are clarified.

Organization	Yes or No	Question 8 Comment
Manitoba Hydro	No	Even though this version of the standard does seem to have addressed Paragraph 284 of Order 733, we still do not agree with the uniform effective date without taking into consideration how many critical circuits or equipment could be added for an individual utility.
American Electric Power	No	It is unclear how much time a TO, GO, or DP would have to implement the changes based on the results of the analysis by the Planning Coordinator. In addition, the Effective Date section is a one-time event upon regulatory approval. What are the on-going implementation expectations? There should be some allowed lead beyond initial implementation after facilities are identified by the Planning Coordinator.
ITC Holdings	No	The new effective dates for 5.1.2 will for the most part be ok. Some of these below 200 kV lines will have to be reconstructed to be able to have adequate protection and meet the required loadability. It will be difficult to do this in 39 months. We suggest a mitigation program be required for those lines that will be difficult to meet the 39 month deadline.
Duke Energy	No	Until we see the criteria for Attachment B, we can't agree that 39 months is sufficient time.
ISO New England Inc.	No	While we agree removing the footnote is straight forward and addresses one Commission directive. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues a regional entities critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
Long Island Power Authority	No	
Northeast Power Coordinating Council	Yes	
FirstEnergy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Ameren	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

9. **Do you agree that the scope of the proposed standards action addresses the directive or directives?**

Summary Consideration:

The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, some commenters indicated this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. The SDT reviewed the SAR and determined a modification to the SAR is unnecessary because the SDT already has considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project.

Several commenters indicated that the directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. This was an error in the SAR and the SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.

Organization	Yes or No	Question 9 Comment
FirstEnergy	No	i. The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. ii. The directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. iii. As mentioned in our response to Question 7, we do not agree with how the project is proposing to address the P. 264 directive.
Response: The SDT reviewed the SAR and determined a modification to the SAR regarding P.162 is unnecessary because the SDT already has considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project. **The reference to P.224 was omitted from the detailed section of the SAR by error. The SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.** **Please see our response above to your comment regarding P.264**		
IRC Standards Review	No	We largely believe the scope will allow the drafting team to address the directives. However, we request that

Organization	Yes or No	Question 9 Comment
Committee		the scope be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693.There is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the Reliability Coordinator, which we do not believe is appropriate.
Response: The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative. **The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.**		
MRO's NERC Standards Review Subcommittee	No	It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Response: Thank you for your input.		
E.ON U.S. LLC	No	See commented sections above. Also, the directive identified in Paragraph 224 was not included in the detailed description or highlighted in Attachment 1 of the SAR. However it was included in the proposed modifications as R4.
Response: The reference to P.224 was omitted from the detailed section of the SAR by error. The SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023. Requirement R5 does not address the directive in P.224 directly as this is a directive to the ERO to provide data upon request. Since the data is subject to audit, the SDT interprets this to mean that the ERO must gather and have continuously available a list of facilities using Requirement R1 criterion 12. Requirement R5 ensures that the data is available.		
TSGT System Planning Group	No	As stated in our earlier comments, we believe that some proposals exceed the directives. It is also not clear how p 162 was addressed in PRC-023-2 as indicated on SAR-3.
Response: The SDT notes that this directive is not addressed in PRC-023-2. The SDT considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project.		

Organization	Yes or No	Question 9 Comment
NPPD	No	
American Electric Power	No	Refer to our comment under question 1.
Response: Please see our response above to your comment on Question 1.		
Pepco Holdings, Inc - Affiliates	Yes	While the scope of the proposed standards action addresses the directive(s) outlined in FERC Order 733 we believe that there are two significant issues that need to be much more thoroughly investigated before being included. Those areas are the inclusion of supervising elements in the existing relay loadability standard and the development of any new standard that would “require the use of protective relay systems that can differentiate between faults and stable power swings and when necessary phase out protective relay systems that cannot meet this requirement.”
Response: In response to industry concerns regarding supervisory elements, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to state: “1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications.” The SDT also modified the second bulleted item in section 2.1 to add the clause, “except as noted in section 1.6 above.” The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733. **The issues related to power swings will be addressed in Phase III of this project according to the SAR, and the NERC System Protection and Control Subcommittee (SPCS) and Transmission Issues Subcommittee (TIS) are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.**		
American Transmission Company	Yes	It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Response: Thank you for your input.		
Kansas City Power & Light	Yes	Agree that the SDT has made revisions that attempted to address the FERC directives. Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
Response: Please see our responses above to your comment on Questions 1 through 8.		
Independent Electricity System Operator	Yes	As indicated in our comment submitted under Q1, there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.

Organization	Yes or No	Question 9 Comment
Response: The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.		
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
Long Island Power Authority	Yes	
ITC Holdings	Yes	
	Yes	

Organization	Yes or No	Question 9 Comment
Duke Energy	Yes	
Wisconsin Electric		No comment

10. Can you identify an equally efficient and effective method of achieving the reliability intent of the directive or directives?

Summary Consideration:

Many comments were offered regarding the directives in Paragraph 150 of Order 733 that NERC "develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement," and suggested that this subject either needs to be addressed via modification to TPL-001 or that it needs further study. It is notable that this issue is to be addressed in Phase III of this project according to the SAR, and that the SPCS and TIS are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.

Many other commenters repeated comments that were offered in response to other questions.

Organization	Yes or No	Question 10 Comment
American Electric Power	No	Not at this time, but AEP would like to consider all viable options throughout the standard development process.
Response: Thank you for your input.		
FirstEnergy	No	Regarding the directive of Par. 264, since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission's directive.
Response: The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.		
IRC Standards Review Committee	No	We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
Response: The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues identified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input		

Organization	Yes or No	Question 10 Comment
through the NERC Standard Development Process.		
Dominion Electric Market Policy	No	Since there is no question that asks if there are other concerns with this draft, I will add one here..... R2 should be modified to read “The Each Transmission Owner, Generator Owner, or and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall forward this information to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The burden for acknowledging agreement or specifying reasons for disagreement should reside with the Planning Coordinator, Transmission Operator, and Reliability Coordinator. Suggest SDT develop additional requirements similar to those in FAC-008 @ R2 and R3.
Response: This proposal is outside the scope of the SAR that is intended to limit the project to addressing the directives in Order No. 733. This suggestion could be made when the standard is reviewed during the required 5-year review of the standard.		
ISO New England Inc.	No	We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
Response: The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process.		
NV Energy	No	NERC's proposed Phase I, II, II process seems reasonable.
Response: Thank you for your support.		
ComEd	No	No, other than the comments provided for question 7.
Response: Please see our responses above to your comment on Question 7.		
Dominion Electric Market Policy	No	
PacifiCorp	No	
Southern Company	No	

Organization	Yes or No	Question 10 Comment
NPPD	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	No other comments.
ITC Holdings	No	
	No	
Northeast Power Coordinating Council	No	
Duke Energy	No	
Bonneville Power Administration	No	
TSGT System Planning Group	Yes	We included specific proposals in our comments to questions 2, 4, 5, and 6.
Response: Please see our responses above to your comment on Questions 2, 4, 5, and 6.		
Manitoba Hydro	Yes	The effective date can be dependent upon how many critical circuits or equipment are identified for each individual company.
Response: The SDT considered this possibility in developing effective dates for each requirement in the standard.		
Consumers Energy	Yes	NERC should, again, oppose the FERC directive in paragraph 264, since, as explained above, this directive is both unnecessary and detrimental to reliability.
Response: In response to industry concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to state: "1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 to add the clause, "except as noted in section 1.6 above."		

Organization	Yes or No	Question 10 Comment
Long Island Power Authority	Yes	Involving industry working groups such as IEEE, EPRI, etc who have proven technical experts will also help in effectively achieving reliability.
Response: The NERC System Protection and Control Subcommittee (SPCS) will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.		
Pepco Holdings, Inc - Affiliates	Yes	Regarding the response of protective relay systems to stable power swings, Draft 5 of TPL-001-2 Requirement R4 (stability assessment) section 4.3.1 requires a contingency analysis be performed which includes “tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models.” Therefore the impact of power swings on relay operation is already addressed in TPL-001. If the tripping of a line is identified during this study phase the impact of the line trip is assessed to ensure the system meets the performance criteria identified in Table 1. If not, mitigating measures would be required, such as modifying that protection scheme to prevent its operation during a stable power swing. However, this would be done on a case by case basis when identified. This seems a much more prudent approach than to require “all protection systems be modified to prevent operation during stable power swings.” That would be similar to requiring the re-conductoring all lines so that they could never experience an overload. Also, Appendix F of the “PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards” employs a methodology to address relay response during power swings by calculating a transient load limit for the relay instead of just the steady state limit identified in PRC-023. The relay loadability is evaluated at the maximum projection along the +R axis (the most susceptible point for swings to enter) rather than at a 30 degree load angle. Various multiplying factors are used to account for the relay operating time delay. This methodology of calculating relay transient loadability limits, which was developed by the PJM Relay Subcommittee over 30 years ago, has worked extremely well in eliminating relay operations during stable power swings. In summary, there are other methods to evaluate and improve the performance of protection systems during power swings short of hardware replacements. All options should be evaluated
Response: The issues related to power swings will be addressed in Phase III of this project according to the SAR, and the NERC System Protection and Control Subcommittee (SPCS) and Transmission Issues Subcommittee (TIS) are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.		
MRO's NERC Standards Review Subcommittee	Yes	On the topic of ‘adding in’ - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
Response: The SDT believes the proposed criteria in Attachment B defining the test Planning Coordinators will use to determine which facilities must		

Organization	Yes or No	Question 10 Comment
comply with PRC-023 will address the commenters concerns.		
American Transmission Company	Yes	On the topic of 'adding in' - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
Response: The SDT believes the proposed criteria in Attachment B defining the test Planning Coordinators will use to determine which facilities must comply with PRC-023 will address the commenters concerns.		
ERCOT ISO		ERCOT ISO thinks a standard drafting team can evaluate the Order 733 directives, work in conjunction with other Standard Drafting Teams already addressing some aspects of critical facilities, may be able to more succinctly arrive at an equally efficient and effective method of achieving the intent of the directive(s). The coordination between teams is vital to avoid confusion and possible overlap.
Response: The SDT has addressed the specific comment regarding coordination with the Reliability Coordination SDT (Project 2006-06) by modifying the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes that the directed modifications to PRC-023-1 contained in Order No. 733 are unique to this standard and do not require coordination with other SDTs.		
E.ON U.S. LLC	Yes	
Wisconsin Electric		No comment

11. **Do you agree with the scope of the proposed standards action?**

Summary Consideration:

Several commenters indicated that they do not agree with the scope of the proposed standards action based on the technical comments submitted against many of the proposed actions submitted in response to the original FERC NOPR on PRC-023. In response, the SDT indicated that FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.

Several commenters indicated that the scope of the SAR should be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693. In response the SDT cited the Standards Process Manual. The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative.

Many comments received indicated that the proposed modifications to PRC-023 reach beyond the directives without specifying which particular modifications are problematic. The SDT worked carefully to not go beyond the directives.

A commenter indicated that the scope should address apparent conflicts in timing of requirements posed by the standard. A newly proposed implementation plan will be proposed in the formal posting of PRC-023 that allows transition time for entities to become compliant with the modified requirements. The SDT agrees that a revised implementation plan is necessary and will post it for review by the industry during the next posting of the standard.

Some commenters suggested that several parts of the standard go too far (Appendix A R1.10) and will require documenting faults and clearing times to prove the fault duty of transformer connections. They also suggested the requirements to deal with out of step blocking relays should go in phase 3 and not in this standard. The SDT believes that evidence such as coordination curves or summaries of calculations are sufficient to demonstrate that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. The potential for out-of-step blocking protection elements to assert due to system load conditions already is addressed in PRC-023-1. Moving this subject from Attachment A to an explicit requirement in PRC-023-2 does not alter the requirement that already exists for Transmission Owners, Generator Owners, and Planning Coordinators. The SDT also notes that operation of out-of-step blocking elements due to system load conditions is outside the scope of Phase III of this project which is to address the directive regarding protection system operation during power swings.

Some commenters noted believe that removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The SDT has modified section 1.6 in response to concerns that applying the standard to elements such as fault detectors that supervise directional distance elements could have a negative impact on reliability. The SDT has modified section 1.6 to include "Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 (formerly 3.1) to add the clause, "except as noted in section 1.6 above."

Organization	Yes or No	Question 11 Comment
Pepco Holdings, Inc - Affiliates	No	We do not agree with the scope of the proposed standards action for numerous reasons. The documented responses to the original FERC NOPR on PRC-023 from numerous sources, including NERC and EEI, together make a rather convincing technical argument against many of these proposed actions. We support these technical arguments, which for the sake of brevity will not be repeated here. In addition, we have provided comments and objections on specific portions of the proposed standards action in our responses to questions 1 through 10 above.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
MRO's NERC Standards Review Subcommittee	No	We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone's best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
American Transmission Company	No	We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone's best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
PacifiCorp	No	It is very difficult to comment on test parameters that have not been determined.
Response: The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were posted on September 23 for a		

Organization	Yes or No	Question 11 Comment
20-day informal comment period. The SDT has reviewed Requirement R5 and the criteria in Attachment B and has made conforming changes to ensure no conflicts exist. The full standard with Attachment B will be posted for a 45-day formal comment period.		
Kansas City Power & Light	No	Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
Response: Thank you for your comments. Please see the summary considerations above.		
ISO New England Inc.	No	We largely believe the scope will allow the drafting team to address the directives. However, we request that the scope be modified to make clear that the drafting may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693. **Response: The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative.** The scope should address apparent conflicts in the timing of requirements posed by the standard. It is our understanding that, based on the final date afforded NERC to develop the criteria for the determination of sub-200 kV facilities,a newly proposed implementation plan will be offered to allow the Planning Coordinators an appropriate time frame to apply the criteria to determine the "critical" facilities below 200 kV. The implementation plan should cause the effective date for circuits described in 4.1.2 and 4.1.4 to be changed from "39 months following applicable regulatory approvals" to a date linked to the Planning Coordinators schedule to provide a list to its TOs, GOs and DPs. **Response: The SDT modified the implementation schedule for those requirements that the SDT has modified to address a FERC directive in Order No. 733. In addition, the SDT added a requirement, now Requirement R7, that requires the Transmission Owners, Generator Owners, and Distribution Providers to implement Requirement R1, Requirement R2, Requirement R3, and Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.12 by the later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list, or the first day of the first calendar quarter of the year in which criterion B6 first applies.**
Duke Energy	No	o The SAR states that Paragraph 162 is part of Phase I, but the new standard addressing stable power

Organization	Yes or No	Question 11 Comment
		swings is Phase III.
Response: The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. The SDT reviewed the SAR and determined to leave this in Phase I because the directive says to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings but agrees that a new standard will be developed for this in Phase III of the project.		
ITC Holdings	No	Several parts of the standard go too far (Appendix A R1.10) and will require us to document faults and clearing times to prove the fault duty of transformer connections. Also the requirements to deal with out of step blocking relays should go in phase 3 and not in this standard.
Response: This is part of the existing, approved standard and the SDT cannot change this part of the standard since it is not associated with a directive in Order No. 733. The SDT removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays. Phase III of this project will address protective relays operating unnecessarily due to stable power swings and is not intended to address out of step blocking relays.		
	No	Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Response: The SDT has modified section 1.6 in response to concerns that applying the standard to elements such as fault detectors that supervise directional distance elements could have a negative impact on reliability. The SDT has modified section 1.6 to include "Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 (formerly 3.1) to add the clause, "except as noted in section 1.6 above."		
E.ON U.S. LLC	No	
NPPD	No	
FirstEnergy	Yes	We agree that this standards action is necessary to meet the FERC directives, but have some concerns as we have stated in previous responses above.
Response: Thank you for your comments. Please see the summary considerations above.		

Organization	Yes or No	Question 11 Comment
TSGT System Planning Group	Yes	We agree that the scope meets the FERC directive, but some of the proposals in the proposed standard reach beyond the directive.
Response: Without additional details, the SDT cannot address the issues that the commenter has with the specific modifications to PRC-023-2 intended to address the FERC directives.		
Independent Electricity System Operator	Yes	We general agree with the proposed action but there are detailed changes that we have comments on, which are noted in our comments under Q1 to Q8
Response: Thank you for your comments. Please see the summary considerations above.		
ComEd	Yes	Yes, given that we assume that NERC must address all the FERC directives whether or not NERC or the industry agrees with them.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
Long Island Power Authority	Yes	LIPA agrees with the scope in general. Please consider our comments above for answers to specific issues.
Response: Thank you for your comments. Please see the summary considerations above.		
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 11 Comment
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Wisconsin Electric		No comment

12. **Are you aware of any regional variances that we should consider with this SAR?**

Summary Consideration:

The majority of the commenters did not identify variances for consideration in the SAR. However, several commenters did point out that each Regional Entity has its own definition for BES and should be considered when addressing sub-100 kV facilities. In response, the SDT indicated that Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that supports the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.

One commenter indicated concern that utilities with long lines and in weak areas will have difficulty protecting their lines and meeting the required loadability. Regions where there are very rural systems will want to write standards that allow adequate protection for their systems. Requirement R1 part 13 states that: "Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations." This was included in the standard for such cases where additional criteria are necessary.

Organization	Yes or No	Question 12 Comment
IRC Standards Review Committee	No	We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV		

Organization	Yes or No	Question 12 Comment
threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		
ISO New England Inc.	No	We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		
Long Island Power Authority	Yes	NPCC BPS definition based on A10 criteria is a regional variance.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		

Organization	Yes or No	Question 12 Comment
ITC Holdings		Utilities with long lines and in weak areas will have difficulty protecting their lines and meeting the required loadability. Regions where there are very rural systems will want to write standards that allow adequate protection for their systems.
Response: Requirement R1 part 13 states that: “Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.” This was included in the standard for such cases where additional criteria are necessary.		
Northeast Power Coordinating Council	No	
Pepco Holdings, Inc - Affiliates	No	
PSEG Companies	No	
Bonneville Power Administration	No	
FirstEnergy	No	
MRO's NERC Standards Review Subcommittee	No	
Dominion Electric Market Policy	No	
E.ON U.S. LLC	No	
Arizona Public Service Company	No	
American Transmission Company	No	
PacifiCorp	No	
Southern Company	No	

Organization	Yes or No	Question 12 Comment
TSGT System Planning Group	No	
NV Energy	No	
NPPD	No	
Consumers Energy	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
ComEd	No	
Manitoba Hydro	No	
Wisconsin Electric	No	
Ameren	No	
American Electric Power	No	
	No	
Duke Energy	No	

13. **Are you aware of any associated business practices that we should consider with this SAR?**

Summary Consideration:

Commenters did not indicate that there are any business practices that the team should consider with the SAR.

One commenter suggested that R2 should be modified to read "The Each Transmission Owner, Generator Owner, or and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall forward this information to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The burden for acknowledging agreement or specifying reasons for disagreement should reside with the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The commenter suggested that the SDT develop additional requirements similar to those in FAC-008 @ R2 and R3. This proposal is outside the scope of the SAR that is intended to limit the project to addressing the directives in Order No. 733. This suggestion could be made when the standard is reviewed during the required 5-year review of the standard.

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	No	
Pepco Holdings, Inc - Affiliates	No	
PSEG Companies	No	
Bonneville Power Administration	No	
FirstEnergy	No	
IRC Standards Review Committee	No	
MRO's NERC Standards Review	No	

Organization	Yes or No	Question 13 Comment
Subcommittee		
E.ON U.S. LLC	No	
Arizona Public Service Company	No	
American Transmission Company	No	
PacifiCorp	No	
Southern Company	No	
TSGT System Planning Group	No	
Consumers Energy	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
ComEd	No	
Manitoba Hydro	No	
Wisconsin Electric	No	
ISO New England Inc.	No	
Long Island Power Authority	No	

Organization	Yes or No	Question 13 Comment
Ameren	No	
American Electric Power	No	
ITC Holdings	No	
	No	
Duke Energy	No	
NPPD	Yes	See Question 7.