NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Relay Loadability Order — Project 2010-13

The Relay Loadability Order Drafting Team thanks all commenters who submitted comments on the proposed applicability test contained in Attachment B to PRC-023-2. These standards were posted for a 20-day abbreviated public comment period from September 23, 2010 through October 12, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 39 sets of comments, including comments from more than 117 different people from approximately 95 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

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										X

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

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

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1
21.	Michael Schiavone	National Grid	NPCC	1
22.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Steve Alexanderson	Pacific Northwest Small Public Power Utility Comment Group			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ronald Sporseen	Blachly-Lane Electric Cooperative		3
2.	Ronald Sporseen	Central Electric Cooperative		3
3.	Ronald Sporseen	Consumers Power		3
4.	Ronald Sporseen	Clearwater Power Company		3
5.	Ronald Sporseen	Douglas Electric Cooperative		3
6.	Ronald Sporseen	Fall River Rural Electric Cooperative		3
7.	Ronald Sporseen	Northern Lights		3
8.	Ronald Sporseen	Lane Electric Cooperative		3
9.	Ronald Sporseen	Lincoln Electric Cooperative		3
10.	Ronald Sporseen	Raft River Rural Electric Cooperative		3
11.	Ronald Sporseen	Lost River Electric Cooperative		3
12.	Ronald Sporseen	Salmon River Electric Cooperative		3
13.	Ronald Sporseen	Umatilla Electric Cooperative		3
14.	Ronald Sporseen	Coos-Curry Electric Cooperative		3
15.	Ronald Sporseen	West Oregon Electric Cooperative		3
16.	Ronald Sporseen	Pacific Northwest Generating Cooperative		5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Ronald Sporseen	Power Resources Cooperative		3									
18.	Russell A. Noble	Cowlitz County PUD No. 1		3, 4, 5									
19.	Dave Proebstel	Clallam County PUD		3									
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

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

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

Additional Member	Additional Organization	Region	Segment Selection
1. John Sullivan	Ameren Services Company	SERC	1
2. Charles Long	Entergy	SERC	1
3. James Manning	North Carolina Electric Membership Corporation	SERC	3
4. Jim Kelley	PowerSouth Energy Cooperative	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

5.	Bob Jones	Southern Company Services, Inc. - Trans.	SERC	1
6.	Pat Huntley	SERC Reliability Corporation	SERC	10

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Potomac Electric Power Company	RFC	1
2.	Walt Blackwell	Potomac Electric Power Company	RFC	1
3.	Carl Kinsley	Delmarva Power & Light Co.	RFC	1
4.	Jason Parsick	Potomac Electric Power Company	RFC	1
5.	Evan Sage	Potomac Electric Power Company	RFC	1
6.	Rob Wharton	Atlantic City Electric	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Bill Middaugh	System Protection Department	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Pearsall	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
2.	Gary Preslan	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
3.	Matthew Leyba	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
4.	LeRoy Martinez	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rich Maxwell	FE	RFC	
2.	Doug Hohlbaugh	FE	RFC	
3.	Jeff Mackauer	FE	RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								

Additional Member	Additional Organization	Region	Segment Selection	
1.	Joe O'Brien	NIPSCO	RFC	1
2.	Terry Harbour	MidAmerican	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

3.	Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
4.	Barb Kedrowski	We Energies	RFC	3, 4, 5
5.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
6.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6
7.	Kirit Shah	Ameren	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Louis Slade, Jr.	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Garton	Electric Mkt. Policy	RFC	5, 6
2.	Michael Gildea	Electric Mkt. Policy	MRO	5, 6
3.	Angela Park	Electric Tranmission	SERC	1, 3
4.	John Loftis	Electric Tranmission	SERC	1, 3

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

Additional Member	Additional Organization	Region	Segment Selection	
1.	Lorissa Jones	BPA, Transmission Reliability Program	WECC	1
2.	Dick Winters	BPA, Transmission Substation Operations	WECC	1
3.	Curt Wilkins	BPA, Transmission Control Cntr HW Design & Maint	WECC	1
4.	Steve Larson	BPA Legal	WECC	1
5.	Rita Coppernoll	BPA, Transmission SPC Technical Svcs	WECC	1
6.	Dean Bender	BPA, Transmission SPC Technical Svcs	WECC	1
7.	Chuck Matthews	BPA, Transmission Planning	WECC	1
8.	Berhanu Tesema	BPA, Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
12.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	Individual	Rick Drury	East Kentucky Power Cooperative, Inc.	X		X		X					
14.	Individual	Andy Tillery	Southern Company	X		X							
15.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
16.	Individual	Cathy Koch	Operational Compliance	X		X		X					
17.	Individual	Donna Jordan	California ISO		X								
18.	Individual	Robin W. Blanton	Piedmont EMC			X							
19.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
20.	Individual	Jonathan Appelbaum	United Illuminating	X									
21.	Individual	Ted Risher	Ingleside Cogeneration, LP					X					
22.	Individual	Kathleen Goodman	ISO New England Inc.		X								
23.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
24.	Individual	Bill Miller	ComEd	X		X							
25.	Individual	Terry Harbour	MidAmerican Energy	X									
26.	Individual	Jerry Tang	MEAG Power	X		X		X					
27.	Individual	JC Culberson	EROCT		X								
28.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Randi Woodward	Minnesota Power	X		X		X	X				
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Steve Rueckert	WECC										X
33.	Individual	Chifong Thomas	Pacific Gas and Electric Company	X		X		X					
34.	Individual	Stephen R. Stafford	Georgia Transmission Corporation	X									
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Armin Klusman	CenterPoint Energy	X									
37.	Individual	Charles Lawrence	American Transmission Company	X									
38.	Individual	Alice Murdock Ireland	Xcel Energy	X		X		X	X				
39.	Group	Ben Li	IRC Standards Review Committee		X								

1. **Attachment B is intended to contain the test that the Planning Coordinators must use to determine whether a sub-200kV facility is critical to the reliability of the bulk power system. Do you agree that the method proposed in Attachment B is a technically sound approach to determine whether a sub-200kV facility is critical to the reliability of the bulk power system?**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Support conformance with PRC-003 for all circuits 100 kV and above and as long as a reasonable period of time is allowed for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Further clarification is needed for Criterion #2 because the circuits which make up an IROL can change depending upon the state of the system, while evaluation of relay loadability must be done in advance. The following language is proposed: Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.Criterion #3 is unclear. The term “directly related to” (off-site power supply to nuclear plants”) is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant, and which form a critical path to supply backup power to the plant, then the criterion should be clarified. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement. This is unnecessary. This criterion needs to be revised such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded, and also to limit its applicability to circuits that provide critical off-site power to nuclear plants as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2.Criterion #4 does not belong in this standard, and should be eliminated. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. NUC-001-2 already requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: o coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) o incorporate the NPIRs into their planning analyses of the electric system (R3) o incorporate the NPIRs into their operating analyses of the electric system (R4.1) o operate the electric system to meet the NPIRs (R4.2).Criterion #6 should be deleted. The PC and TP assess their future systems according to the performance requirements

Organization	Yes or No	Question 1 Comment
		stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Pacific Northwest Small Public Power Utility Comment Group	No	The comment group agrees with all the criteria but number 6. Consider a local loop above 100 kV that is fed from a single radial tap from the BES. Some regions continue to treat such radially fed systems as BES due to the presence of normally open tie switches on the distribution system. It is conceivable that a multiple contingency within the loop could cause one or more of the remaining un-faulted lines within the loop to overload to beyond 115% of their short term ratings. While undesirable, such a scenario does not rise to the level of a BES event. Even if the lines cannot overload, entities will be required to run simulations to prove non-applicability where such systems should be excluded by simple inspection.The comment group suggests that radially operated (operated is the key word here) systems be excluded.
MRO's NERC Standards Review Subcommittee	No	In general, Midwest Reliability Organization's NERC Standards Review Subcommittee (NSRS) agrees with the proposed criteria. However, there should be further clarification and qualification of the criteria noted below.In the introduction, the wording of "determine if that circuit needs to be evaluated for conformance with PRC-023" does not clearly tie to Requirement R5.1 or use the same language. We suggest revised wording to more clearly refer to Requirement R5.1 by using the more similar language of, "determine the circuits that are critical to the reliability of the BES".For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, "for the near term planning horizon", to the end of criteria #4.For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, ". . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between".We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical.

Organization	Yes or No	Question 1 Comment
		Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical.For Criteria #5, we suggest that the applicable entities be changed. The Transmission Planner should be added because they have local planning responsibilities and knowledge that should be factored into the consideration of critical circuit classification. We suggest that the Regional Entity be removed because it does not fall within the Reliability Assurer functional tasks.
SERC Planning Standards Subcommittee	No	Although this question states Attachment B contains the critical facilities test, it instead appears to contain a listing of facilities to evaluate to determine if they are critical, and not the test itself. Attachment B states that if any of the criteria apply to a circuit, the circuit needs to be evaluated. It should state that the circuit should be considered critical.Item1 should be removed since not all flowgates are related to reliability. The remaining items adequately cover lines less than 200 kV that are critical to reliability.Item 3 contains a typo. Change "are" to "is."Item 3: The word "related" is too vague, recommend to use the word "connected" instead.Item 6 is confusing and should be revised as follows: "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without system adjustments in between." The comments expressed herein represent a consensus of theviews of the above-named members of the SERC EC Planning StandardsSubcommittee only and should not be construed as the position ofSERC Reliability Corporation, its board, or its officers.
Pepco Holdings, Inc. - Affiliates	No	Mitigation timeframes are identified on the unofficial comment form, which differ from those defined by the implementation plan in the most recent draft version of the standard. To be enforceable all mitigation timeframes need to be identified in the standard itself. Secondly, the mitigation timeframes in the comment form use phrases like “by the time the overload problem would be expected” and “before the operating time being analyzed”. The timeframe requirements for mitigation need to be better defined to be auditable. The Planning Coordinator needs to determine an “exact date” when the mitigation is required prior to the overload taking place. If that date is more than 24 months away then the protection system owner will have to mitigate the facility before the required date established by the Planning Coordinator. However, if the projected overload date is less than 24 months away, the protection system owner will have 24 months after being notified by the Planning Coordinator to mitigate the facility; and operators shall be made aware of the loadability limitation and should operate the facility accordingly until the facility is mitigated. The issue is that it may take 24 months for the protection system owner to make necessary hardware upgrades to mitigate the loadability limitation.
System Protection Department	No	1. We think that criterion 1 should be changed as follows “... Texas Interconnection, or path in the Western Interconnection that is listed as an Existing Path in the current year WECC Path Rating Catalog.” The current

Organization	Yes or No	Question 1 Comment
		wording “rated path in the Western Interconnection” is too general and could be interpreted to mean any element in the Western Interconnection that has a thermal rating.2. Change “are” in criterion 3 to “is.”3. We think that criterion 5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is no basis listed for determining circuits in this criterion, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. Protection system owners do not want transmission elements to be removed from service due to loading and nothing precludes a protection system owner from applying PRC-023 requirements to lower voltage lines. We also think that getting agreement between the three required entities could be troublesome.If some form of criterion 5 is included in the Attachment B, then it needs to define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement. It seems that criterion 6 defeats the need for criterion 5.4. We think that criterion 6 should be revised to read as “Each transmission line operated between 100 kV and 200 kV that exceeds its highest seasonal 15-minute Facility Rating or each transformer operated between 100 kV and 200 kV that exceeds its operator established emergency transformer rating as a result of a double contingency...” The current wording would have no positive impact on BES reliability. First, the existing term “Short Term Emergency Rating” is not defined and is not used in PRC-023. We are suggesting changing the concept to terms that are used in the standard. Secondly, nothing in PRC-023 requires the protection system owner to set the relays to operate at more than 115% of an emergency rating or a short term (15-minute) rating. An element loading that qualifies under the drafting team's proposed criterion 6 would not have to be considered unless it exceeded the 115% of the emergency or short term rating, which the protection system settings would not be required to permit per the requirements of PRC-023. That is why we changed the criterion to indicate inclusion of the element for any loading that exceeded the emergency or short term rating for the contingencies studied.
FirstEnergy	No	FirstEnergy has the following comments related to the proposed criterion presented in the Attachment B of PRC-023-2. A. Consistency with the CIP-002-4 bright-line criteria. When comparing the proposed PRC-023-2 Attachment B criterion to the bright-line criteria proposed for CIP-002-4 Attachment 1 Critical Asset determination there is a great deal of overlap in concepts presented for transmission facilities. For example, each cover aspects of transmission facilities associated with IROLs and transmission facilities that are operationally significant for the safe operation and shutdown of a nuclear generation plant. Since these are parallel standard development efforts we suggest to the extent possible the PRC team and CIP team use consistent language when equivalent technical concepts are utilized for critical facility determinations. FirstEnergy's suggested changes identified below for the six individual criterion are consistent with CIP-002-4 Attachment 1 proposals made by FirstEnergy. B. Leverage existing studies and analysis - planning timeframe. We concur with the drafting team’s perspective that tests for the applicability of PRC-023 should leverage as much existing work as possible, however, FE believes any study/analysis work should be limited to that performed by the planning coordinators and transmission planners and not the transmission operators as

Organization	Yes or No	Question 1 Comment
		suggested by the comment form background information. FE believes the appropriate timeframe to identify the sub 200kV critical facilities is the planning horizon based on forward looking studies conducted by or under the supervision of the planning coordinator. This is consistent with PRC-023-1 (R3) and the proposed PRC-023-2 (R5) since the planning coordinator is the applicable entity required to determine the sub 200kV critical facilities and the time-horizon for the requirement is long-term planning. Information based on analysis performed by the reliability coordinator or transmission operator within the operating time horizon, such IROL, can be temporary, dynamic and subject to change. Therefore, it should be clear that the intent of facilities associated with IROLs are based on planning timeframe analysis. See FE's proposed changes to the second criterion. C. Mitigation Timeframes. The comment form provided by the drafting team presented two criteria for mitigation timeframe. This information should not be buried in a comment form but rather part or the standard's Effective Date's section (Section 5) and presented in an Implementation Plan so that it may be fully vetted by industry through the standards development process. The mitigation timeframe should be clear that the minimum expectation is 24-months upon the asset owner being notified by the planning coordinator of a new critical facility determination. The first bulleted item presented by the team is vague if its meant to be the "greater of" or "lesser of" 24 months or the time the overload problem would be expected. As stated above, FE believes that critical facility determinations are appropriately based on planning horizon timeframes and therefore it should be clear that an asset owner is afforded a minimum 24-month period to mitigate any critical facility required to meet PRC-023. This is consistent with the approved version 1 and the proposed version 2 standard.D. Specific comments on the Attachment B Criterion.i. Criteria 1: A flowgate should not be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates are used for market recognition to study the impact of schedules on a particular interface and may not present a reliability concern. The team should consider a more limiting use of flowgate or striking the criteria.ii. Criteria 2: FE agrees with the concept of associating a critical facility with IROL however we believe two important revisions are required. First, the critical facility should be based on the contingent facilities that describe the IROL and not the monitored elements. Second, the IROL determinations should be based on planning horizon studies. FirstEnergy proposes the following text for criteria 2: "Transmission Facilities that the Planning Coordinator or Transmission Planner designates that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL)."iii. Criteria 3: FE supports criteria 3 and proposes revision so that criteria 3 reads “BES Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.”iv. Criteria 4: Criteria 4 should be removed since criteria 3, as revised above, should adequately cover the transmission facilities deemed critical for a nuclear generation facility as designated in their NPIRs.v. Criteria 5: Criteria 5 is vague, open ended and should be removed. Any criteria that the PC may use to include other facilities should be explicitly stated in Attachment B. The RC should be removed since it makes evaluations within the operating horizon timeframe which is not appropriate for requirement R5.vi. Criteria 6: FE supports this criteria.

Organization	Yes or No	Question 1 Comment
Midwest ISO Standards Collaborators	No	We have many concerns with the approach identified. We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical. Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, the IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical.For criterion 2, we believe any contingent facility or prior outage that sets up the IROL should be included if criterion 6 is revised to allow operator intervention between contingencies. If criterion 6 is not revised, we do not support adding contingency or prior outages.For criterion 3, what does it mean to be directly related to the off-site supply to nuclear plants? Does this means it is identified in the NPIRs associated with the agreements mandated by NUC-001-2? This criteria needs to be further refined if retained.For criterion 4, since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage.For criterion 5, this criterion is too open ended and should be eliminated. Since the Regional Entity is the auditor, they should not provide direct input into what is included. This seems like carte blanche for the Regional Entity to add to the list of facilities whenever the latest issue arises. Could we end up having a situation where after every event analysis the Regional Entity identifies even more facilities? If the Regional Entities have needs to identify facilities they should do this by providing input through the standards development process to suggest modifications to the criteria. Will the RC and PC be judged similar to how entities are currently being judged regarding the number of Critical Assets that have been identified for CIP? If so, this could become a “bring me a rock” exercise. If the PC and RC don’t identify enough facilities, will the ERO and Regional Entities pressure them to identify more? Industry will be better served if we eliminate this open ended criteria and just identify bright line criteria for what should be included. This really seems like a catch all in case we forget to add all the necessary criteria.For criterion 6, we disagree with this criterion because it exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards.
Dominion	No	While items 1-5 seem reasonable, Dominion takes exception with item six (6). Item six goes beyond TPL-003

Organization	Yes or No	Question 1 Comment
		criteria, by assuming the operator will have no time between contingency events to make system adjustments. TPL-003 was thoroughly vetted when it was developed and is sound criteria that has been in place for years. Circuits below 200 kV are less critical to the security of the bulk electric system. We see no reason why the standard should not allow that the operator will make system adjustments between the first and second contingency.
Bonneville Power Administration	No	BPA would like to raise the concern regarding the terminology being used in PRC-023. An underlying principle of the standard is to "Determine which of the facilities in its Planning Coordinator Area are critical to the reliability of the BES...". BPA would like to take this opportunity to point out that determination of “critical” as PRC-023 is applied may not be directly reflective of CIP Critical Asset identification. BPA feels this is appropriate due to the guidance provided in CIP-002 R1 where the Risk-Based Assessment Methodology should include the following considerations (as we used to develop BPA's methodology): 1) Control centers and backup control centers; 2) Transmission substations that support the reliable operation of the Bulk Electric System; 3) Generation resources that support the reliable operation of the Bulk Electric System; 4) Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration; 5) Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more; 6) Special Protection Systems that support the reliable operation of the Bulk Electric System; and 7) Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment. No minimum kV levels are instructed to be specifically used to identify CIP Critical Assets where PRC-023 is heavily driven by kV levels. BPA believes it would be very labor intensive to try and come up with which circuits would exceed the STE rating by 15% or more. BPA would like to understand the benefit of this study to increasing reliability.For Attachment B, BPA believes the performance requirement needs to be clarified further. The term "double contingency" and reference to "TPL-003" needs to be more specific, since TPL does cover more than just N-2 contingency of circuit elements. Additionally, regarding the Standard itself, for some local areas, if three lines are feeding the local area and it has been planned per the Standards (e.g. one single 115 kV line can't feed 100% of load in the area for loss of the other two), it seems like if two of the lines are lost simultaneously, then loss of the third line quickly, rather than waiting for an operator response may be preferable. This could be a safety issue and the operator may have no control over outcome. Additional comments:BPA would find it helpful if the drafting team were to create a cross-walk of the FERC directives (as listed on Page 3 and 4 of the SAR) and how/where the drafting team is addressing them.
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
East Kentucky Power Cooperative, Inc.	No	East Kentucky Power Cooperative (EKPC) agrees in principle with the establishment of criteria to be used to identify circuits to be evaluated for conformance with PRC-023-2. However, EKPC does not believe that all of the proposed criteria are appropriate. For instance, the first listed criterion that specifies any circuit listed as the monitored element of a flowgate appears to be excessive. EKPC does not believe that flowgates necessarily correspond with a critical facility requiring further analysis of relay settings. EKPC also does not agree with the

Organization	Yes or No	Question 1 Comment
		6th listed criterion as stated. We propose that the criterion be modified to allow system adjustments between contingencies in accordance with the TPL-003 standard. EKPC feels that this criterion stated in Attachment B should maintain consistency with the requirements for system performance stated in TPL-003. With the elimination of the first criterion listed in Attachment B and the modification of the 6th listed criterion to allow system adjustments between contingencies, EKPC would support the method listed in Attachment B for identification of critical circuits.
Southern Company	Yes	For clarity, it is suggested that the two sentences above the criteria list of Attachment B be revised as follows: Review each (line and transformer) circuit less than 200 kV against the following criteria to determine if that circuit must conform with PRC-023. If any of the criteria below apply to the circuit under review, the circuit must conform to the requirements of PRC-023.
Salt River Project	No	There is an error in the wording under R5, this requirement states "transmission lines operated at below 200kV and transformers below 230kV." It should state "transmission lines operated between 100kV and 200kV and transformers operated between 100kV and 200kV" otherwise this standard will fall out of the definition of BES.
Operational Compliance	Yes	We would like to propose a rewrite for criterion #6. The proposed rewrite is:"Each circuit operated between 100 kV and 200 kV that exceeds its short term Emergency Rating by 15% or more as the result of a double contingency, beyond the requirements of TPL-003 C3 (i.e. loss of a single circuit followed by the loss of a second circuit without manual system adjustments in between), for all combinations selected by engineering judgment in the TPL-003 C3 analyses." Note - This modified TPL-003 C3 contingency reflects a situation where a System Operator may not have time between two contingencies to make appropriate system adjustments.The term “Short Term Emergency Rating” is not a defined term so “short term” should not be capitalized and could potentially be removed. The definition of Emergency Rating specifies a finite time period. The addition of the word 'manual' before 'system adjustment' mirrors the TPL-003 C3 definition and better clarifies what is meant by 'system adjustment' as this is not a defined term. This would then imply that automatic system adjustments that occur due to RAS and SPS operations, transformer tap changes and automatic switching of reactive resources would not constitute a 'system adjustment' in the context of this criterion (further supported by the note to criterion #6).
California ISO	No	Further clarifications to the criteria in Attachment B are required.
Piedmont EMC	Yes	I would like to have a provision in the Standard so that all radial transmission lines are excluded from this requirement since they are not used for load transfer. Otherwise, a lot of utilities will have to comply wiht this Standard by stating that we do not have any critical lines and have a letter from the TO stating that we don't have any critical lines.
Kansas City Power & Light	No	Do not agree with the approach in R5 and R5.1 in proposed Standard PRC-023-2 to dictate to the Planning Coordinator additional criteria beyond the TPL Standards to identify operating sensitivities. The proposed Appendix B proposes to establish additional considerations of facilities by which the Planning Coordinator must determine if those facilities are 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

Organization	Yes or No	Question 1 Comment
		understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates and other operating sensitivities 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 as proposed here in this Appendix B.
United Illuminating	Yes	We agree with the approach. We are concerned that the periodicity of the determination of the lines between 100 kV and 200 kV is not specified in Attachment B number 6 or R5. Is this an annual determination or performed only when a study for the Planning Horizon is completed. Is the study period the short term planning horizon (1-5 year) or long-term planning horizon (6-10 year)? For a temporary maintenance condition, e.g. a line is removed from service for 14 months, is the PC required to reevaluate the list of facilities?
Ingleside Cogeneration, LP	No	In paragraph 97 of Order 733, FERC allows for entities to challenge the identification of sub-200 kV transmission facilities as critical to the BES. The paragraph reads as follows:"Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule."Most of the proposed criteria leverage well-understood concepts such as violations of IROLs or double contingencies. However, the proposed attachment includes a catchall statement under Criterion #5 that the RC, PC, and RE can designate circuits as critical without any defined basis. This makes an appeals process imperative since there are economic impacts to facility owners of such designations. This process needs to be proposed and evaluated by the industry concurrently with Appendix B, not at a future date.
ISO New England Inc.	No	General comment: ISO New England supports conformance with PRC-003 for all circuits 100 kV and above allowing for a reasonable period of time for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Comments regarding specific criteria:2. Further clarification is needed regarding criterion #2, since the circuits which make up an IROL can change depending upon the state of the system while evaluation of relay loadability must be done in advance. We proposed the following language: Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions."3. The breadth of criterion #3 is unclear and may, as written, be broader than necessary or appropriate. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement, and we believe this to be unnecessary. This criterion needs to be modified such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded and also to limit its applicability to circuits that provide critical off-site power to nuclear plants, as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2.4. Criterion #4 should be eliminated. NUC-001-2 already

Organization	Yes or No	Question 1 Comment
		requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: o coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) o incorporate the NPIRs into their planning analyses of the electric system (R3) o incorporate the NPIRs into their operating analyses of the electric system (R4.1) o operate the electric system to meet the NPIRs (R4.2).6. Criterion #6 is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Manitoba Hydro	No	1) For criteria #5, Regional Entity does not need to be involved in determining the operational significant circuits. It should be changed to: “Each circuit determined and agreed to by the Reliability Coordinator and the Planning Coordinator.”2) For criteria #6, it should be clarified that it would be up to the Planning Coordinator to make the engineering judgment in determining the double contingencies beyond the requirements of TPL-003 standard. In addition, there should be some coordination between the methodology for critical asset determination in the cyber security standards and the relay loadability standard so multiple assessments are not required by the Planning Coordinator. Ideally, the scope of the TPL assessment should provide sufficient information for the other relevant NERC standards.
ComEd	Yes	Criteria number 6 calls for a test that includes comparison to the “Short Term Emergency Rating”. We have had some confusion on exactly which rating this refers to. Thus, our comment is to add some clarifications to this term. For example if this is the rating that is closest to a 15 minute highest seasonal facility rating, state this directly or in a footnote.
MidAmerican Energy	No	The proposed criteria is not technically sound as many of the criteria are completely arbitrary and have no technical basis. The appropriate basis for a critical element is something that could result in instability, uncontrolled separation, or cascading which is the basis for all NERC standards, the 2003 blackout, and the Energy Policy Act wording. The following proposed criteria is not technically sound and should be deleted:1. Being a flowgate or monitored element of a flowgate. The loss of a flowgate that doesn’t result in the instability, uncontrolled separation or cascading, may pose no more jeopardy to grid reliability than any other element that isn’t designated as a flowgate. This was proved by FERC’s own TIER report.2. A circuit agreed to by the RC, PC, and RE. This has absolutely no technical basis whatever and is completely arbitrary. This requirement also completely excludes the actual owner / operator of the facilities.3. A circuit that exceeds 15% of its short-term emergency rating as a result of a double contingency. This criteria exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards. This completely ignores any

Organization	Yes or No	Question 1 Comment
		unusual or temporary operating conditions that could result from ice storms or even maintenance practices.
MEAG Power	Yes	A minor clarification is needed. The first line under Criteria reads,"Review each circuit (line and transformer) less than 200 kV needs ..." It needs to be reworded as follows: "Review each circuit (line and low-side transformer) between 100 kV and 200 kV needs ..."The first line of number 6 needs to be reworded by deleting "between 100 kV and 200 kV." It would now read, " EAch circuit operated that exceeds its Short Term ..."
EROCT	No	In response to Attachment B of PRC-023, ERCOT ISO respectfully submits the following comments:Criterion 1 - the phrase "Commercially Significant Constraint in the Texas Interconnection" and the associated footnote should be removed. Commercially Significant Constraints (CSCs) are market-driven constraints designed to economically manage congestion under the ERCOT Zonal market construct. CSCs are not reliability constraints that reflect the criticality of an element relative to system reliability. Furthermore, as noted in footnote 1 in Attachment B, the ERCOT market is transitioning from the current Zonal construct to a Nodal construct on December 1, 2010. Under the Nodal design CSCs will not exist. Accordingly, the rules that apply to CSCs will expire prior to the implementation of this rule.Criterion 3 - The word "are" should be replaced with the word "is".Criterion 4 - There should not be any circuits whose outage causes unacceptable voltages on the off-site power bus at a nuclear plant. Therefore, this criterion should be removed.Criterion 6 - Short Term Emergency Rating is not a defined term. Accordingly, it is not clear what rating is at issue. Emergency Rating is a defined term, and ERCOT assumes that is the rating envisioned by this criticality identifier. If that is the case, it needs to be clarified. If some other rating is envisioned, that too needs to be clarified, because, as noted, Short Term Emergency Rating is not defined.
American Electric Power	No	These AEP comments are provided in the context of the primary goal of this standard as specified under R5, "... to prevent cascading ...". The fundamental concern behind these comments is that the implemented methodology should not unnecessarily and erroneously classify facilities as "critical", even for the limited purposes of this single standard. Such labels should only be applied to facilities that are truly "critical" to the reliability of the Bulk Electric System, and thus, the implemented methodology should only identify "critical" facilities. In addition, the implementation plan must allow for ample time to mitigate the initial wave of "critical" facilities that would reasonably be expected to be significantly larger than the incremental number of new "critical" facilities that will be identified on a routine basis going forward. Specific comments on the posted criteria being proposed by NERC are outline below.(1) Flowgates in the Eastern Interconnection (and Commercially Significant Constraints in the Texas Interconnection) are defined for various reasons and not just for reliability purposes. Flowgates are defined for interface monitoring, congestion management, and other purposes unrelated to reliability. Many of the flowgates reflect nominal normal and emergency ratings to limit loadings on these facilities below their thermal capabilities, and not for the purpose of preventing cascading. As such, being part of a flowgate definition alone should not be the basis for suspecting susceptibility to cascading, and thus, not a good reason for having such facilities meet the requirements of this standard. Furthermore, flowgates are updated on a continuous, and many times, temporary basis, and thus, not a practical basis for identifying facilities for the purposes of this standard. Therefore, this criterion should not be used as a basis for defining "critical" facilities for the purposes of this standard.(2) Since the identification of

Organization	Yes or No	Question 1 Comment
		"critical" facilities is made by the Planning Coordinators in the planning horizon (to give the relay owners ample time to address compliance with the requirements of this standard), then the IROL methodology that is applicable to the planning horizon (as specified under FAC-010) must be used to identify such "critical" facilities. In the case of PJM, IROL facilities in the planning horizon are those SOL facilities that have been identified as potentially resulting in cascading outages. As such, system reinforcements are developed in the planning horizon to ensure that such cascading conditions are mitigated and do not materialize in the eventual operating horizon. Consequently, PJM does not define any IROL facilities in the planning horizon. Therefore, this criterion can not be used as a basis for defining "critical" facilities in the planning horizon for the purposes of this standard. On the other hand, IROL facilities identified in the operating horizon (as specified under FAC-011), would be appropriate to use to identify "critical" facilities for the purposes of this standard.(3) On the surface, this appears to be a reasonable criterion. However, need to clarify what is meant by "directly related". If these are facilities that are identified under the NPIRs mandated under NUC-001, then their associated relay loadability performance should be addressed under NUC-001. Moving this requirement from PRC-023 to NUC-001 will ensure that all requirements associated with nuclear plants are addressed together under the same standard (NUC-001).(4) On the surface, this appears to be a reasonable criterion. However, when such voltage studies are conducted and unacceptable voltage conditions are identified in the planning horizon, system reinforcements and other mitigating actions are taken to ensure that such conditions do not occur in the operating horizon. Consequently, since no such conditions will be allowed to remain, then no "critical" facilities should result from this criterion. On that basis, this criterion should be eliminated. If the criterion is kept, then it should be moved under NUC-001 for the same reasons noted under criterion 3. Also, the criterion needs to specify the starting point of the outage analysis that identifies the unacceptable voltages. Furthermore, the outaged facility needs to be subject to heavy loadings to be considered for possible designation as a "critical" facility. The outage of the facility for reasons unrelated to heavy loadings should not be a basis for making that facility subject to the requirements of this standard.(5) This criterion is too open ended and should be eliminated. As the auditing entity, the Reliability Entity should not be providing any input outside of the auditing process. The Planning Coordinator has the flexibility to engage any other entities as it sees fit, and thus, there is no need to single out the Reliability Coordinator under this criterion. Also, even if these entities were kept and others, such as the Transmission Owners, were added, what would be the basis that these entities would use to identify these "critical" facilities? Again, this criterion is too open ended, it does not add anything meaningful to the effort, and thus, it should be eliminated.(6) On the surface, this appears to be a rational basis for identifying "critical" facilities since it utilizes cascading simulations. However, it stops short of performing the N-1-1-1 simulations (declares all overloaded facilities after the N-1-1 simulations as "critical" rather than going the extra step of performing the N-1-1-1 simulations to determine if any additional facilities become overloaded) that are needed to demonstrate susceptibility to cascading. Furthermore, an additional filter, one that takes into consideration the amount of load that would be placed at risk by the N-1-1-1 cascading scenario, also needs to be incorporated into this methodology. This can best be achieved by giving the TOs an opportunity to review the preliminary results from their Planning Coordinator and to demonstrate to their Planning Coordinator as to

Organization	Yes or No	Question 1 Comment
		the amount of load that would be at risk through the cascading of the proposed “critical” facilities. If the TOs can successfully demonstrate to their Planning Coordinator that for certain facilities the amount of load that would be at-risk (from the cascading scenario) falls below a specified threshold level (to be determined by their Planning Coordinator), then those facilities would be excluded from the final list of “critical” facilities. In the end, this should be the only criterion that is used to identify “critical” facilities for the purposes of this standard. Regarding the use of Short Term Emergency Ratings in the simulations, it should be noted that most ratings used in planning base cases (the ones that would be used by the Planning Coordinator) are Long Term Emergency Ratings, and thus, converting such models to reflect Short Term Emergency Ratings just for the purposes of conducting these simulations would not be practical. Therefore, the specification should be made as a higher percentage of Long Term Emergency Ratings.
Minnesota Power	No	Minnesota Power recommends that the Standards Drafting Team consider changing item #6 to read as follows:Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency (for those combinations selected by engineering judgment in TPL-003 System Performance Following Loss of Two or More BES Elements analyses).
Independent Electricity System Operator	No	We agree with Criteria # 1, 2 and 5, but do not agree with Criteria #3, #4 and #6.Criterion #3 is unclear. The term “directly related to” (off-site power supply to nuclear plants” is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant and which form a critical path for supply backup power to the plant, then the criterion should say so to provide better clarity.Criterion #4 does not belong in this standard. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. Criterion #6 is troublesome and perhaps not needed. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. We suggest to remove this Criterion #6.
Ameren	No	Criterion #1 : A monitored flowgate does not imply a reliability issue. Flowgates are monitored for many reasons, some for reliability and some to regulate the amount of firm transmission service. In non-FTR markets, firm transmission monitoring may be a partial function of reliability. However, in FTR markets, the sale of firm transmission service may be related to the acquisition of ARR/FTRs. Under these scenarios, the flowgate may be in place to ensure FTR funding sufficiency. Circuits with high degrees of uncertain loading are most susceptible but the mere presence of uncertainty does not make them critical for the reliability of the BES.Criterion #2: We are ok with the element related to “IROL” type criterion including outage of such element

Organization	Yes or No	Question 1 Comment
		causing instability or cascading effect on the BES. Criterion #3: We believe that our comment should be restated as “This criterion should not be included in a relay loadability test. The fact that a circuit supplies a reserve aux transformer at a nuclear plant does not make the circuit critical to the transmission network or to the plant. If the outage of a circuit results in the outage or instability of a nuclear plant, then these issues should have been addressed in the design of the plant supply and/or in the TPL-002 assessment.”Criterion 4: This issue should be covered in TPL-002 or NUC-001. This item should not be included in a relay loadability test.Criterion #5: This is an open-ended criterion without any supporting basis. It is also unclear who at the Regional Entity would “sign-off”, Compliance, Engineering, or someone else? Further, this type of criterion would introduce more inconsistencies rather uniformity. If such a criterion is used, we suggest that the RC, PC, and/or RE should work closely with the local Transmission Planners to determine if a circuit should be assessed for criticality and further subjected to the relay loadability test.Criterion #6: Short Term Emergency Rating, although capitalized in here, is not a NERC defined term. Further, the criterion does not identify the time duration that the STE rating would be applicable, nor the basis for such a rating. If a common time duration and basis for rating could be established, a common loading above the STE rating could be established. A loading of 120% may be more indicative of a cascade than 115%, and would be applicable for fast acting contingencies involving multiple circuits, including Category C1 bus faults, C2 breaker failures, or C5 double-circuit tower outages. We do not agree with the proposal that system adjustments would not be allowed for slower multiple contingency Category C3 events (sometimes referred to as N-1-1 outages) involving lines, generators or transformers, as this requirements clearly steps on standard TPL-003.
WECC	No	The approach described is reasonable, however, it would be more comprehensive and consistent to replace in item 1 (Attachment B), "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". This Table is more comprehensive because it is identified by the WECC Operating Committee and is consistent with the major paths used in other WECC Standards.Item 5 appears vague. What does “agreed to by the Reliability Coordinator, the Planning Coordinator, and Regional Entity mean?” Do all three need to be in agreement before a facility is to be added to the list to be evaluated, or can any one of them add it to the list? How are these entities supposed to come to agreement and document that agreement. If there is not a proactive effort to develop the list and “agree” to it, there probably won’t be a list.I’m not sure I understand Item 6. Does this mean that results of TPL-003 assessments will helpt identify circuits that have to be evaluated? TPL-003 is eventually going to go away when the ATFNSDT effort is completed. The requirement to conduct the types of assessments currently included in TPL-003 will not go away, but the specific referenct to TPL-003 could become obsolete.
Pacific Gas and Electric Company	No	We believe the approach described is reasonable, however, as written Item 1 (Attachment B) concerning WECC paths is vague. We suggest, replacing "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". We believe referencing this Table would provide clarity because the paths in this Table are identified by the Operating Committee in WECC and are consistent with the major paths used in other WECC Standards, such as FAC-501-WECC-1, PRC-004-WECC-1, and TOP-007-WECC-1.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	No	Criterion 6 of Attachment B states "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency..." The basis for the 15 percent criterion has not been clearly explained. What is the basis for this criterion? Based on this criterion, multiple lines could be identified as critical facilities, when, in fact, loss of these lines could have no significant impact to the BES(i.e. not cause cascading outages on the BES).
Duke Energy	No	o General Comment - It should be made clear that the application of these criteria is intended to determine which facilities must be evaluated for applicability of PRC-023-2 and may not necessarily dictate modification of relay settings. Situations where there is time for operator intervention, or no cascading, wouldn't need loadability protection. o Criteria 1 - We do not believe that flowgates should be automatically included as a criteria, since a flowgate may be in the IDC for business reasons. Also, the list of flowgates is dynamic. o Criteria 2 - Monitored elements of an IROL are also dynamic and we question how you could apply this in the planning timeframe so it could be used to set relays. IROLs identified in the planning horizon should be mitigated by some action prior to reaching the operating horizon. This criteria is not specific enough to be applied consistently. o Criteria 3 - What is meant by "directly related"? There is a difference between normal off-site power and emergency power. We don't think the NPIRs would clarify this situation. Is the expectation that no lines connected to a nuclear plant trip except for a fault on the line? o Criteria 4 - If we had such a circuit it would violate TPL-002 as well as the NPIRs, so this is not a useful criteria, because you'll never identify anything with it. o Criteria 5 - It doesn't make sense to include the Regional Entity, because the Regional Entity doesn't do the analysis. Also, this criteria just says you can go beyond the existing criteria, which is always an option - so why include it as a criteria? o Criteria 6 - "Short Term Emergency Rating" is not a defined term. However its use in conjunction with the 15% overload suggests that a 15-minute Emergency Rating is what is intended. Some Transmission Owners haven't determined sufficiently short term Emergency Ratings to meet the intent of this criteria, and if they set their relays at 115% of their shortest term Emergency Rating they would restrict loadability more than the standard should allow. Regardless of how the criteria for contingency line loading are defined in Attachment B, the criteria should match the requirements of PRC-023-2.
CenterPoint Energy	No	Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, CenterPoint Energy believes sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria 6 that proposes loading greater than 15% of the short term emergency rating following a double contingency is not a technically sound method to indicate if an element is operationally significant. CenterPoint Energy recommends only criteria 1 through 5 be used to determine whether a sub-200 kV element is operationally significant to the reliability of the bulk power system.
American Transmission Company	No	In general, we agree with the proposed criteria. However, we propose the following changes to the introduction, Criteria #4 and Criteria #6. [[1]]- In the introduction, the wording of "determine if that circuit needs to be evaluated for conformance with PRC-023" does not clearly refer to Requirement R5.1 or use the same language as R5.1. We believe that the wording in Attachment B should match the wording in R5.1. However, use of the terminology, "critical to reliability of the BES", keeps causing confusion with the meaning of the

Organization	Yes or No	Question 1 Comment
		concept of "critical" as it is defined in the CIP-002 standard. Therefore, we propose replacing the "critical" terminology in R5.1 with distinctly different terminology like, "that have major operational significance to the reliability of the BES". Then, use wording similar to R5.1 in Attachment B such as, "determine the circuits that have major operational significance to the reliability of the BES". [[2]]- For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, "for the near term planning horizon", to the end of criteria #4. [[3]]- For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, ". . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between".
Xcel Energy	No	Item 1 - it is not clear how 'temporary flowgates' would be considered I this application; "commercial" considerations should not be part of a reliability standard; "rated path" in WECC is not clear - are these any path in the WECC Path Catalog, or is it intended to mean the "Major WECC Paths..."?Item 4 - we feel it should be eliminated from the list of criteria. Since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage.Item 5 - this appears to give carte blanche authority to the PC/RC/RE to decide a circuit is subject to evaluation; we believe this should be tempered with concurrence from the TO/GO/DP.
IRC Standards Review Committee	No	Criterion 1 is inappropriate and should be eliminated. It states that any monitored facility below 200KV would be subject to this standard. A facility that is designated as a flowgate should NOT be automatically assumed to have an impact on reliability. Flowgates are included in the IDC for many reasons and not always because the facilities are critical to bulk system reliability. Some flowgates are defined and included in the IDC only to have the PTDF, OTDF and LODF calculated. In general, flowgates are not a good indicator for reliability needs; the master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Furthermore, IDC is primarily used to study congestion and is the basis of Transmission Loading Relief (TLR) which is not a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should NOT be relied upon to relieve IROLs that have been violated and other actions such as redispatch must be used in conjunction with TLR. Criterion 2 should state that any contingent facility or prior outage that sets up the IROL be included, except where such facility is used as a proxy for assessing the IROL. Criterion 3 is unclear and should be clarified. What does it mean to be "directly related" to the off-site supply to nuclear plants? More clarity in the wording is needed. Is the intent that facilities that provide off-site power to nuclear plants as defined in the NPIRs associated with the agreements mandated by NUC-001-2 are captured in this standard?Criterion 4 is not needed since NERC standards already contain

Organization	Yes or No	Question 1 Comment
		requirements to operate the system to N-1 and to plan the system with Category C contingencies. Therefore, this criterion would never identify any facilities whose outage would cause low voltage.Criterion 5 is too open ended and should be eliminated. The Regional Entity serves primarily as the compliance enforcement authority and not the technical assessor of what facilities are critical for bulk power reliability. They do not perform any of the operating and planning functions required to comply with reliability standards. These criteria should strive to be as close as possible to “bright line” tests. Criterion 5 is in a sense rhetorical, like defining a word with the same word.Criterion #6 should be deleted. This criterion does not recognize that the system is neither planned nor operated to allow for two overlapping outages without operator action in between. This goes beyond the assessment and performance requirements of TPL-003, where operator actions can be assumed between the first and second contingencies. We also ask why a 15% over Short Term Emergency Rating is an appropriate level, there is no justification.

END OF REPORT