Comment Report

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 3
Comment Period Start Date:	7/22/2024
Comment Period End Date:	8/12/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 3 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 3 ST

There were 60 sets of responses, including comments from approximately 151 different people from approximately 105 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

3. Provide any additional comments for the Drafting Team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO

					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,NPCC,RF,SERC,SPP RE,Texas RE,WECC	SRC 2024	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Greg Campoli	NYISO	1	NPCC
					Matt Goldberg	ISO New England	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC

FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power	10	NPCC

Coordinating Council						Coordinating Council		
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC

					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC

						Charles Norton	Sacramento Municipal Utility District	6	WECC
						Wei Shao	Sacramento Municipal Utility District	1	WECC
						Foung Mua	Sacramento Municipal Utility District	4	WECC
						Nicole Goi	Sacramento Municipal Utility District	5	WECC
						Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you believe there are alternatives or more cost-effective options to address the recommendations in the FERC Order? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports the scope of this standard and finds no alternatives or more cost-effective options for consideration.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Revisit PRC-030-2 Standard within 2-years to allow applicable personnel cognizant of its capabilities to be better prepared to recognize cost-effective options or recommendations to answer this question.	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI Comments	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no suggested alternatives over what has been proposed within PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

We concur with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC has signed on to ACES comments:

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period. Changes in Real Power for the following are excluded:

• Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;

• Resource dispatch, resource ramping, planned outages, or planned resource testing;

• A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or

• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

• identifying a Real Power change event pursuant to Requirement R1 or,

• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
SMEs responded with the following comments: • "Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards."	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	Yes
Document Name	
Comment	
"Although this is a better version than the previous draft, and it more specifically gets to the root of what the need is, this standard is still an extension of MOD-033 and PRC-002, and now also PRC-004. There does not seem to be enough justification to add a separate standard (and the additional personnel hours required to fulfill it) when the effects could likely be accomplished by updating existing standards."	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

1. We believe the original directive extracted from the last sentence of Paragraph 208 of FERC Order No. 901 has been taken out of context. According to Paragraph 208, as identified by the Standards Drafting Team (SDT) as the purpose for the proposed NERC Reliability Standard PRC-030-1, the Commission directed NERC to develop a "new or modified Reliability Standards that require post-disturbance ramp rates for registered IBRs to be unrestricted and not programmed to artificially interfere with the resource returning to a pre-disturbance output level in a quick and stable manner after a Bulk-Power System disturbance event. The proposed Reliability Standards must account for the technical differences between registered IBRs and synchronous generation resources, such as registered IBRs' faster control capability to ramp power output down or up when capacity is available. Further, the Reliability Standards must require generator owners to communicate to the relevant planning coordinators, transmission planners, reliability coordinators, transmission operators, and balancing authorities the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels (i.e., generation-load balance)." If should be noted that most of this paragraph is currently being addressed under NERC Standard Development Project2020-02, Modifications to PRC-024 (Generator Ride-through). If the purpose of NERC Reliability Standard PRC-030-1 is to require Generator Owners to communicate the actual post-disturbance ramp rates and the ramp rates to meet expected dispatch levels and provide that information to other entities, we believe a simpler approach could be taken.
2. For instance, there are already data provisions requirements under NERC Reliability Standard MOD-032-1, IRO-010-5, and TOP-003-5 for entities to include in their data specifications to "request" data like ramp rates to meet expected dispatch levels from Generator Owners. Hence, NERC Reliability Standard PRC-030-1 should be condensed to only provide actual ramp rate (operational) data following a Disturbance. This is like the data request concepts listed within the proposed NERC Reliability Standard PRC-028-1. In that Standard, data is provided to a requested entity based on an observed exception to normal operations. As currently proposed, the Generator Owner has as little 15 calendar days to provide data over a 20-calendar day period. We believe a similar approach should be followed in NERC Reliability Standard PRC-030-1 and allow the Generator Owner 15 calendar days to work with their Generator Operator to collect operational data, including actual ramp rates, that were recorded during a period before, during, and after a Disturbance.

Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

We are highly concerned that, relative to the first draft, the current draft of the standard reduces the threshold for output change events that must be reviewed to determine if they need to be analyzed. The revised standard sets the threshold at a change in output that is greater than 10% of the plant's nameplate rating (and greater than 20 MW) within 4 seconds, relative to the threshold of 20% within 2 seconds in the initial draft. This change only adds to our concerns about the generator owner's burden of manually reviewing each output change to exclude events caused by normal fluctuations in plant output due to weather, dispatch, and other factors. No mechanism exists for generator owners to automatically exclude those permissible changes from consideration. Wind and solar plants have a limited number of meteorological towers and pyranometers for measuring the available wind and solar resource, respectively, which makes it difficult in many cases to precisely determine whether changes in output across a plant were caused by resource availability.

The new lower threshold will pick up many more such events, as changes of 10% output within 4 seconds can routinely occur at solar and wind plants. As we explained in our previous comments, the passage of clouds over medium-sized solar plants can cause changes in output that are larger than this threshold.[1] As a result, in some cases a large share of the events a generator owner is required to review will be these normal changes in output, diverting their time and resources away from addressing real reliability concerns.

The drafting team's response to our comments in the first round of balloting only reinforces our concern about the burden imposed on the generator owner: "GOs would not know if it was unexpected behavior of generator settings and controls until the analysis is performed. The exceptions that have been moved from the footnote to the Standard Language allow for GOs to dismiss events due to cloud cover, change in wind speed. etc. Outage/Fault codes would be reviewed during the analysis process. It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis." It is highly burdensome for a generator owner to pull turbine- or inverter-level fault codes and plant-level fault codes for each event with a more than 10% change in output. Moreover, the drafting team cannot ignore the excessive and unworkable burden imposed on generator owners by simply dismissing that with "It will be up to GOs to develop a process to identify events that that do not fit into the listed exclusions and require further analysis."

As explained in our answer to question 2 below, the best solution to these concerns may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event that causes a drop in generator output per R2.

Second, we are concerned that generator owners will be required to conduct a full analysis of all events in which an IBR plant reduces real power output to prioritize reactive power output, as is desirable and expected during voltage disturbances. The standard should be revised to include a mechanism to automatically screen out disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

During a voltage disturbance on the bulk power system, the most helpful response is typically for generators to shift some of their power output from providing real power to prioritizing reactive power to help prevent voltage collapse.[2] As experts at the Energy Systems Integration Group (ESIG) explain, summarizing the conclusions of a recent workshop on generator interconnection, "If too much active power is injected into a point of interconnection with already depressed voltage, it may further collapse the voltage, causing more cascading outages and compromising the reliability of the grid. Rather than keeping the active power of an IBR at a pre-disturbance level, it is more beneficial to reduce active power, depending on severity of voltage drop thus preventing further voltage collapse — while reactive power is prioritized and increased to support grid and terminal voltage."[3]

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve. In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

To address the concerns expressed in our answer to question 1 above regarding the burden on generators of screening out changes in output that are not caused by disturbances, the best solution may be to remove most if not all of R1, and instead rely on analysis requests initiated by the Reliability Coordinator, Balancing Authority, or Transmission Operator following a disturbance event per R2. This would remove the inefficient "needle in the haystack" burden on generators under R1 to screen every output change event to find the small subset that are due to disturbances, and instead only focus resources on reviewing significant disturbance events that coincided with a change in generator output. Because many generators do not have synchrophasors or other equipment required to determine when significant grid disturbances have occurred, it makes more sense for the analysis to be initiated by a request from the RC, BA, or TO. Relatedly, we reiterate our request from the first comment period to add a requirement to R2 that the RC, BA, or TO must file its request within 15 days of the disturbance event. This will ensure that the GO has at least five days to pull data before it is overwritten, given that the data retention period in the current draft of PRC-028 R7 is 20 days.

As explained above, the standard should also be revised to include a mechanism to exclude analysis of disturbance events in which the IBR generator briefly reduced real power output because it entered reactive power priority mode.

Finally, the requirement on the generator owner in 2.1.4 to "Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities" appears to be unreasonable if not unworkable. A company that owns multiple IBR plants typically uses different equipment and settings across its plants, and some may be wind plants while others are solar plants, so there is no reason to assume its other plants have the same susceptibility simply because they have the same owner. At minimum, the requirement should be clarified to specify whether projects owned by the same parent company but that are incorporated as separate LLCs must be assessed as part of compliance with 2.1.4., and other such details.

If PRC-30 continues to fall short of the level of support required for approval in this round of balloting, and NERC proceeds under Rules of Procedure Rule 321.2.1 by having the Standards Committee convene a technical conference and use the input from the technical conference to revise the standard for a final re-balloting period, these changes would help to secure sufficient support for the standard to pass during re-balloting.

{C}[1]{C} https://www.sciencedirect.com/science/article/abs/pii/S0306261917300144

{C}[2] https://www.esig.energy/download/interconnection-requirements-need-for-harmonization-jason-macdowell/?wpdmdl=9267&refresh=62f587eab15591660258282, at 6

{C}[3]{C} https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf, at 29

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock

Answer	Yes
Document Name	
Comment	

TransAlta supports Entergy's comment:

"A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System."

Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	Yes
Document Name	
Comment	

The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	
Comment	

Constellation aligns with the NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
The MRO NSRF does not believe that this is cost-effective as currently proposed. Please see the MRO NSRF's other responses to questions. Perhaps determining subsections of the North American electric grid where this detailed monitoring and analysis is most needed rather than requiring it across the entire geographic area. The system stiffness to voltage and frequency fluctuations should be accounted for in regions where the IBR facilities are not likely to be affected by abnormal system condition events. Any possible reduction in the number of facilities required to install this equipment is a direct cost reduction.	
Likes 1	Western Area Power Administration, 1, Hammer Ben
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Capital Power supports the NAGF's comments: *The NAGF membership is concerned with the time/effort required to perform event identification and post-event performance validation. Even with automation, the process will require Generator Owner (GO) personnel to analyze and identify those IBR facility power change events that require corrective actions. The NAGF members believe that this will impose a significant human capital burden for GO registered entities.*	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation aligns with NAGF comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	Yes
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

NERC and FERC should allow PRC-024-3 and PRC-029 to be implemented to allow for corrections/requirements to take place and then evaluate if PRC-030 and its requirements as currently proposed are actually needed.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	Yes
Document Name	

Comment

Buckeye supports the comments made by ACES:

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period. Changes in Real Power for the following are excluded:
• Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
• Resource dispatch, resource ramping, planned outages, or planned resource testing;
• A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
• Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.
Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:
R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:
• identifying a Real Power change event pursuant to Requirement R1 or,
• receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1
2.1. Analyze its IBR facility performance during the event, including:
2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility’s Ride-through performance including Reactive Power response during the event;
2.1.3. Assess any performance issues identified and if corrective actions are needed; and
2.1.4. Determine the applicability of the root cause(s) to the Generator Owner’s other Inverter-Based Resource facilities.
2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.
Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?
Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to

the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3,5 - WECC

Answer	Yes
Document Name	

Comment

Please consider the following:

1. Overlap with Existing Standards: The new standard is seen as an extension of existing standards (MOD-033, PRC-002, PRC-004) and may not justify the additional personnel hours required.

2. Cost-Effectiveness: A more efficient approach would be for Transmission Operators to identify necessary service data events and have Generation Plants provide the data, rather than evaluating all potential events.

3. Clarification of Directives: The original directive from FERC Order No. 901 has been taken out of context. The proposed standard should focus on providing actual ramp rate operational data following disturbances.

4. Existing Data Provisions: There are already data provision requirements under other NERC standards (MOD-032-1, IRO-010-5, TOP-003-5) that could be utilized.

5. Targeted Monitoring: Detailed monitoring and analysis should be focused on specific sections of the grid where it is most needed, rather than across the entire geographic area, to reduce costs.

Likes 0	
Dislikes 0	

Response

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission

Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.

Likes 0	
Dislikes 0	

Response

Rhonda Jones - Invenergy LLC - 5

Answer	Yes
Document Name	

Comment

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. Considerable amounts of time will be required to identify, analyze, and validate every event involving a power change of the applicable magnitude. As an alternative, the SDT could consider revising R1 to require Generator Owners to analyze events only upon request by the applicable Transmission Operator, Balancing Authority, or Reliability Coordinator. This would allow the Generator Owner to focus its resources and efforts on analyzing events of significance to the BES.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	Yes
Document Name	

Comment

It is the opinion of ACES that PRC-030-1 Requirement R1 should be more aligned with PRC-004-6 Requirement R1. In short, we believe that requiring a documented process to identify applicable events at an IBR, as is currently required by PRC-030-1 R1, increases the compliance burden for the GO with no appreciable decrease in the risk to the BPS. Therefore, we recommend striking the phrase “implement a documented process to” from PRC-030-1 Requirement R1. The revised version of R1 would thus read as follows:

R1. Each applicable Generator Owner shall identify any complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period. Changes in Real Power for the following are excluded:

- Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing;
- A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the RC, BA, or TOP being able to require the GO to perform an analysis of any event type chosen by the RC, BA, or TOP. We believe that the event types identified by the RC, BA, or TOP should be inline with the event types identified by the GO in R1. Thus, we recommend modifying Requirement R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 120 calendar days, of either:

· identifying a Real Power change event pursuant to Requirement R1 or,

· receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in Real Power output;

2.1.2. Document the facility's Ride-through performance including Reactive Power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not inline with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and possibly the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt?

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend removing the any portion of these requirements that require the GO to submit a CAP to the RC, BA, and/or TOP.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	Yes
Document Name	

Comment

NV Energy agrees with the NSRF comments that the proposed is no a cost-effection solution.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	

Black Hills Corporation will not comment on alternatives or cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG Energy Inc is in support of the comments made by EPSA.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
NRG agrees with the EPSA comments.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC has no comments	

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	

Comment

Ameren has no comment on the cost effectiveness of this project.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	
Document Name	

Comment

NCPA understands Ferc Order 901 and does not oppose it.

The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective to address recommendations of FERC order 901 or if, or to what extent, this proposal will improve reliability.

Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals.

Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data. And, ironically GO/GOP IBR Entities are being asked to spend money to procure and install a bunch of devices to record data and/or to perform new activities that may, or may not, improve reliability. And if they do improve reliability, we don't have any idea if the reliability benefits are worth the cost. Electricity customers' rates would need to be raised and there is no justification or hard evidence related to the improved reliability increase magnitude; i.e. no cost/benefit justification to provide electricity customers as to why their rates are increasing.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	

2. Does the entity have any concerns regarding the 2023-02 Implementation Plan? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI has no concerns with the Implementation Plan for PRC-030-1	
Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 2	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista agrees with EEI comments	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	
Consider implementing a 2028 implementation date instead of 2027 since most companies have already committed resources relative to bids, etc.; expensive design change requests will be required using the proposed date.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation has no concern with the Implementation Plan	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy offers no comments toward the Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Walkup - Arkansas Electric Cooperative Corporation - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ayslynn Mcavoy - Arkansas Electric Cooperative Corporation - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	

WECC voted yes but offers the following comments/concerns:

PRC-030- Separating the Requirements out by design and operation is not realistic and gives the false appearance of being applicable prior to Jan 1, 2030. The language of the Requirements, as written, are unenforceable from a design perspective for BES IBRs and non-BES IBRs.

Design aspects for the Requirement appear to be as follows (If not DT needs to explicitly explain what the "design" portion of the Requirement language is so that everyone—registered entities, Regions, NERC, and FERC are on the same page) :

R1- Process has to be designed by effective date of Standard for BES IBRs or (later of Jan 1, 2027 or effective date for non-BES IBRs). Effectively review of compliance can not be completed on design as the Requirement language is to "implement" a documented process. If an entity has not designed the "process", it seems the entity would be non-compliant, but the Requirement is unenforceable. The process can not be implemented unless an event occurs which is an operational concern with different timelines. R2 through R4 all depend upon an event occurring.

It also appears that R2-R4 would be unenforcecable as written, becuase if R1 was not complied with, R2 would not be enforceable. If R2 was not complied with, R3 would not be doable and if R3 was not complied with, R4 would not be enforceable.

Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	

Six months after FERC approval is unreasonable to have equipment and procedures in place. Especially considering several entities will need to order and install new monitoring equipment from most likely the same companies. The implementation plan should be the same as PRC028.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	Yes
Document Name	

Comment

WEC Energy Group has a concern with following statements from the Implementation plan:

Bulk-Electric System IBRs: Entities shall comply with the portion of Requirements R1, R2, R3 and R4 relating to the ***design*** *of their BES IBRs to meet the requirements by the effective date of the standard.*

Please clarify what is the "**design**" portion of requirements R1, R2, R3 and R4. If the "design" cannot be clarified, then only R1 should be met by the effective date of the standard and R2, R3 and R4 should follow upon implementation of PRC-029.

Performance-Based Elements (all applicable IBRs) Entities shall not be required to comply with the portion of Requirements R1, R2, R3, and R4 relating to the ***operation*** *of IBRs to meet the requirements until the entity has established the required Ride-through capabilities for those IBRs in accordance with the implementation plan for Reliability Standard PRC-029-1.*

Please clarify what is the "**operation**" portion of requirements R1, R2, R3 and R4.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	Yes
Document Name	

Comment

Ameren recommends an 18-month implementation plan to allow sufficient time for entities to develop a plan as well as to procure and install the necessary equipment.

Likes 0	

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
The implementation period should be increased from 12 months to 36 months to allow for any equipment changes or upgrades needed to comply with the standard.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Extensive detail is required to clarify between design stages and actual operation for phased-in implementation.	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation aligns with NAGF comments.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	

Constellation aligns with the NAGF comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	Yes
Document Name	
Comment	

The implementation plan is unnecessarily convoluted. PRC-030 R1 requires entities to have a documented process, then R2/R3/R4 requires entities to exercise the process which depends on having sufficient SER/FR/DDR equipment installed as per PRC-028. Simply tie the timing of the PRC-030 implementation plan to PRC-028.

Thus, TransAlta proposes to have R1 in place by the effective date of the standard, and R2/R3/R4 in place as the disturbance equipment is installed at the respective IBRs as per PRC-028.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

1. We believe the removal of NERC Reliability Standard PRC-028-1 from the list of Prerequisite Standard(s) is unnecessary. If a Generator Owner is required to provide operational data from a Disturbance impacting their IBR facility, then recorded measurement data associated with that Disturbance would be critical to any post-disturbance analysis. We believe NERC Reliability Standard PRC-028-1 should be added to the list of Prerequisite Standard(s).
2. We believe NERC should coordinate the Implementation Plans for the three standard development projects associated with Milestone 2 of its work plan to address the directives within FERC Order No. 901. This would give most Generator Owners one set of compliance implementation dates to track. The phased-in compliance dates should align with those proposed under NERC Standard Development Project 2021-04, Reliability Standards PRC-002-5 and PRC-028-1, as those dates have been well vented across industry. As that project has proposed for some Generator Owners, this can be as much as within three (3) calendar years of the standard's effective date for 50% of those Generator Owners' BES Inverter-Based Resources. Then the rest of their BES Inverter-Based Resources must be compliant by January 1, 2030. The SDT Project 2021-04 SDT made similar simplifications for other Generator Owners with future IBRs yet to commission and for Category 2 Generator Owners.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

SMUD agrees with the comments submitted by Tennessee Valley Authority.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
Vistra supports comments made by Entergy.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

While we appreciate the change from 6 months to 12 months, this still may not provide enough time for the work to be done considering that the GO may not have the required expertise in-house and, thus, may have to contract the work out to a potentially small number of companies that can do the work. The time it takes to develop a statement of work, issue requests for quotes, obtain the quotes, evaluate the quotes, and issue purchase orders can easily be 6 months. Then the work has to be done by the contractor, reviewed by the GO, any GO comments addressed by the contractor, then re-reviewed by the GO to ensure their comments were addressed, and finally issued by the contractor. Depending on the workload and availability of contractors, getting this done within a possible 6 month timeframe is not necessarily reasonable. We request that the effective date be moved to at least 24 months.

The non-BES compliance date of January 1, 2027, only gives 7 months from the assumed potential registration date of May 2026. While currently non-registered GOs could start the design process early, they may not know if they will be required to be registered until closer to the May 2026 deadline and this won't give them enough time to get work done or will potentially require them to do work that is not required (if they wind up not having to register). Suggest moving this date out to January 1, 2028.

If the IBR operation doesn't have to be changed until the implementation of PRC-029-1, and if the PRC-029-1 gives some number of years to be compliant, which it should, why does the design need to be done withing one year us tot potentially "sit on a shelf" for a few years?

Likes 0	
Dislikes 0	
Response	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	

Comment	
This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet. The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP has no objections for the implementation period to be twelve months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment modifications are necessary for detecting changes to Real Power. This may not be a simple “configuration issue”, as new equipment may be needed to obtain additional data points as it is not explicitly stated in R1 where the measurement needs to be taken. AEP suggests adding text to clarify the measure point as “individually, at each MPT level”, “at the POI”, or some other defined point. AEP recommends that an implementation period of 18 months be allowed instead to accomplish whatever field modifications may be necessary.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Scott Thompson - PNM Resources - 1,3,5 - WECC	
Answer	
Document Name	

Comment

Please consider the following:

1. Timeframe for Compliance: While extending the compliance period from 6 to 12 months is appreciated, it may still be insufficient due to the need for contracting out work, which involves a lengthy process. A 24-month period is suggested.

2. Non-BES Compliance Date: The proposed compliance date of January 1, 2027, is too soon after the potential registration date of May 2026. Extending this to January 1, 2028, is recommended.

3. Design Implementation: If PRC-029-1 allows several years for compliance, the design work required within one year may be premature and unnecessary.

4. Prerequisite Standards: The removal of PRC-028-1 from the list of prerequisite standards is seen as unnecessary. Including it would ensure critical data for post-disturbance analysis is available.

5. Coordination of Implementation Plans: NERC should align the implementation plans for related standards to provide a unified set of compliance dates, simplifying tracking for Generator Owners.

6. Simplification of Implementation Plan: The current plan is considered convoluted. It is suggested to tie the timing of PRC-030 implementation to PRC-028, with phased compliance dates

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	

Comment

ITC has no comments

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	
Document Name	

Comment

NRG agrees with the EPSA comments.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6

Answer	
Document Name	

Comment

NRG Energy Inc is in support of the comments made by EPSA.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends adding the approval of the Inverter-Based Resource (IBR) definition to the prerequisite actions.

Likes 0	
Dislikes 0	
Response	

3. Provide any additional comments for the Drafting Team to consider, if desired.

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

As AEP stated in the previous ballot period, the scope and general intent of PRC-030 appears reasonable, but the process and flow are flawed and need to be changed. The Standard seems to reflect the spirt of the Technical Rationale, but its obligation language doesn't seem to correlate strongly enough with it. While it might be reasonable to simply identify the “event” within 90 days (or 120 days to match PRC-004), additional time will still be needed to research and determine the root cause(s). This could conceivably take 90 days or more, especially if support is needed from the OEM. And once the cause is determined, at least 60 additional days (to match PRC-004) would then be needed to develop the CAP and document the Applicability (R2.1.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then possibly developing the CAP. It cannot be assumed that a root cause will be found in every case, and the standard needs to allow for this. To further illustrate our concern, the standard drafting team provided this response to AEP comments: “The Drafting Team believes it should be up to the GO to develop a process to identify and analyze events. Requirement R2 makes it clear that they have 90 days from the date of the event to complete analysis, regardless of when the event was identified. They also have 90 days to complete analysis of events identified by the BA, RC, or TOP from the date they were notified of the event.” AEP understands this response, however the revisions to the standard do not match this response. Specifically, “that they have 90 days from the date of the event” is not what is written in R2. R2 presently reads “within 90 calendar days of identifying an active power change event”, which has a different meaning. AEP agrees that it should be measured from the date of the event, not the date of identifying an event. One related gap, as we see it, is that it is not explicitly clear how many days are afforded to identify an event, though 90 days are inferred. These collective concerns are the primary driver behind our decision to vote negative on PRC-030.

The timelines for R1 and R2 are clear for situations when the GO has received a request that identifies a Real Power change pursuant to R1, however the timeline is not clear for those cases when the GO self-identifies. As an example, does “within 90 calendar days of identifying an active Real Power change” mean within 90 days of the event itself? AEP requests that language be added to the requirements which makes the timeline clear for both those instances. Once again, some clarity is provided in the Technical Rationale, however it is not clear within the obligations themselves.

The proposed version of PRC-030 assumes that a root cause will be found in every case, but this is not realistic. The standard must be revised to accommodate for situations where a root cause(s) is never found or identified. The SDT recently stated in their Consideration of Comments response that “If no root cause is found, a GO should work with the RC to explain the details of the performance issues and develop a monitoring plan to capture future events,” however we do not see how industry could draw this conclusion from the language currently used.

R2 and R3 include the word “applicable” when referencing the RC, BA, and Transmission Operator, however we believe this word is misleading and may be interpreted inconsistently. As a result, we recommend instead using “associated” which was recently proposed for use in PRC-029-1.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the effort the drafting team has put into drafting these standards. Texas RE has the following comments on PRC-030-1:

In Requirement R1, it seems that the fourth bulleted exclusion would be better suited to be included under Requirement R3. If the reduction in Real Power meeting the appropriate threshold MW is due to a Protection System Misoperation, it would not be immediately evident in real-time, if. This will become evident during performance analysis and can be used as a technical justification that address why corrective actions will not be implemented. Texas RE recommends removing the fourth bullet from Requirement R1 and adding it to Requirement R3. Please see below (in bold):

R3. If performance issues and a need for corrective actions were identified in Requirement R2 Part 2.1.3, each applicable Generator Owner shall, within 60 calendar days of completing the analysis in Requirement R2, develop one of the following and provide it to the applicable Reliability Coordinator, Balancing Authority, and Transmission Operator: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

- A Corrective Action Plan (CAP) for the identified inverter-based resource(s), including other applicable facilities owned by the Generator Owner as identified in Requirement R2 Part 2.1.3; or
- A technical justification that addresses why corrective actions will not be implemented; or
- **Analysis concluded that the Real Power reduction was due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.**

Texas RE noticed in Requirement R2, in the first line, “an” should be changed to “a” since it is referring to Real Power, not active.

Texas RE previously commented Requirement R2, subpart 2.2 seems to require that an additional request be made by the RC, BA, or TOP for the analysis results. Texas RE recommends the phrase “upon request” be removed from subpart 2.2 because Requirement R2 language already includes the ‘request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator’. Please see the revision below (in bold).

Suggestion:

2.2. **Upon request, p**rovide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator

Texas RE recommends Requirement R4 include a timeframe for implementing the Corrective Action Plans. It is essential to implement the CAPs as quickly as practicable to improve the system reliability and risk mitigation. Texas RE recommends the following (in bold):

R4. Each applicable Generator Owner shall, for each of its Corrective Action Plans developed pursuant to Requirement R3 **within 120 days or sooner**:

Technical Rationale - Figure 1.2: Texas RE recommends adding a line from Mitigate (R3) box to a new box “Notification to RC, BA, TOP” to match Requirement R3 language.

Technical Rationale - Figure 1.3: Texas RE recommends adding clarification on the chart to note that the blue line and above is the threshold for meeting the R1 MW criteria, which is greater than or equal to 10%.

Likes 0	
Dislikes 0	

Response

Brian Lindsey - Entergy - 1	
Answer	
Document Name	

Comment

R2. Data quality concern in an event happening in 4 seconds and being able to complete the analysis.

Concerns with having to provide the information to multiple entities.

R3 & R4. The reporting requirement should be synchronized with R3 and R4. Corrective plans should be intended for internal use only and not necessary to be reported out to other entities. What is the need and useability of that information to those entities?

The action to create the Corrective Action Plan should 90 days instead of 60 days. Recommend adding language in R3 that states that if all actions are completed during the analysis phase to correct the issue there will be no need for a CAP.

Likes 0	
Dislikes 0	

Response

Bruce Walkup - Arkansas Electric Cooperative Corporation - 6

Answer	
Document Name	

Comment

None.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

FirstEnergy requests the DT clarify how to ensure cause for changes that are at least 20MW and at least 10% of gross nameplate under the first bullet point for R1 is related to equipment's components rather than issues outside of the control of the GO.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

The standard's Applicability, as indicated in section 4.2, increased from just BES to now include non-BES > 20 MVA. What authority does NERC have, at present, to place requirements on non-BES (and, probably, non-registered) generators? NERC should not be decreeing what the design of non-BES resources should be or have standards that apply to them.

We continue our objection to the R3 requirement that the GO has to provide CAP information from Requirement R2.1.3 to the applicable RC, BA, and TOp if they haven't asked for it. The RC, BA, and TOp may have hundreds of sites that they oversee and work with and having to receive info that they may not need (or even want) places an unnecessary burden on them. Also, having to provide this info, that the RC, BA, or TOp many not need/want, places an undue burden on the GO. If the RC, BA, or TOp need/want this info, let them ask for it individually, or let them put the requirement to submit it to them in their data specifications per TOP-003 and/or IRO-010. Same comment for R4.3.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills Corporation does not support the inclusion of the phrase "The Elements associated with" as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope that is unclear.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	
Document Name	

Comment

Tri-State agrees with the additional comments provided by the MRO NSRF.

Likes 0	

Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

R1. This requires utilities to identify outages on IBR systems “occurring within a 4 second period”. Idaho Power Company (IPC) has several clarifying questions: What does this mean? What 4 second period is being specified here? Does this mean outages less than 4 seconds are not included or does this mean the 4 second period outages are the only ones counted? Alternatively, does this mean that the utility must identify the outage within 4 seconds? IPC feels clarification would be helpful.

R2. The utility is responsible for meeting compliance with Requirement R2.1 (and its subparts) within 90 calendar days; however, IPC wants to emphasize that the manufacturers perform this roots cause analysis. As a result, the utility is dependent on the manufacturer meeting this date, or the utility will be out of compliance. Based on prior experience, this can create challenges in meeting the required 90-day timeline. It should also be noted that some problems are very complicated and root causes take time to develop. There should be additional leniency integrated to account for the time required by third parties to fulfill these requests on behalf of the utilities.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,5,6 - WECC	
Answer	
Document Name	09 - RhodesM - IBR Oscillation Event Report_July 2024.pdf
Comment	

BPA identified that both drafts for PRC-028 and PRC-029 include the new IBR definition in the 'new terms' section. BPA recommends the SDT include the same language in PRC-030-1 for continuity.

BPA recommends including in the 'New Terms' section:

Term(s): The terms Inverter-Based Resource (IBR) refer to proposed definitions being developed under the Project 2020-06 Verifications of Models and Data for Generators. As of this posting, the proposed definition of Inverter-Based Resource is: N/A Inverter-Based Resource (IBR): A plant/facility consisting of individual devices that are capable of exporting Real Power through a power electronic interface(s) such as inverter or converter, and that are operated together as a single resource at a common point of interconnection to the electric system. IBRs include, but are not limited to, plants/facilities with solar photovoltaic (PV), Type 3 and Type 4 wind, battery energy storage system (BESS), and fuel cell devices.

Additionally, BPA recognizes there are growing instances of system oscillations associated with batteries and their metering systems. For awareness, please see the attached IBR Oscillation Event Report for specificity regarding emerging issues. This document was presented at the WECC combined RRC/RAC held July 10, 2024.”

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS supports the following comments submitted by EEI on behalf of its members:

EEI does not support the inclusion of the phrase “The Elements associated with” as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

• Suggest modifying PRC-030-1 R2 to 120 calendar days to align with PRC-004 R1-2 120-day investigation and analysis period.

• Duke Energy agrees with and supports the following EEI comment:

“EEI does not support the inclusion of the phrase “The Elements associated with” as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion.” Rephrase sentence to remove or clarify intent of this phrase.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	
Document Name	

Comment

The language in **Section 4, Applicability** does not match the language used in the latest proposed version of PRC-028-1. Although the language in PRC-030-1 is cleaner and preferred, it is not quite clear what is meant by the inclusion of the words “The Elements associated with” in Section 4.2.1. These words are unnecessary.

SMUD would prefer that the drafting team delete these words and change Section 4, Applicablity to the language below. The language used in Section 4, Applicability for the currently proposed PRC-028-1, PRC-029-1 and PRC-030-1 should match. This change is non-substantive and could be made in the final ballot.

The existing language in PRC-030-1 (and PRC-029-1) is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2 Facilities:

4.2.1. ***The Elements associated with*** (1) Bulk Electric System (BES) IBRs; and (2) Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

The existing language in PRC-028-1 is as follows:

4.1. Functional Entities:

4.1.1. Generator Owner that owns equipment as identified in section 4.2

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV

SMUD’s preferred language in PRC-030-1 Section 4, Applicability is as follows:

4.1 Functional Entities:

4.1.1. Generator Owner

4.2. Facilities:

4.2.1 BES Inverter-Based Resources

4.2.2 Non-BES Inverter-Based Resources that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Likes 0	
Dislikes 0	

Response
Brian Van Gheem - Radian Generation - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

1. We believe the proposed Reliability Standard should be better aligned with the original directive. Requirement R1 should be replaced with a requirement to provide operational data, including actual ramp rates, within 15 calendar days of a request received from an IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority.

2. We believe Requirement R2 has two separate analytical processes combined as one. The first analysis should be like the approach taken in NERC Reliability Standard PRC-004-6 which first confirms the cause of a BES interrupting device operation was from a Misoperation of its Protection System components. In the initial PRC-030-1 analysis and upon notification from a reliability transmission entity, the Generator Owner should confirm no IBR facility performance issues were noted that caused a rapid change in IBR Real Power output. The results of this analysis, including the cause of the change in IBR Real Power output, should then be provided to the Requirement R1 requester (i.e., IBR's Reliability Coordinator, Transmission Operator, or Balancing Authority) within 90 calendar days. If the Generator Owner has confirmed the occurrence of an IBR facility performance issue, then a Corrective Action Plan would be generated under Requirement R3.

3. We believe Requirement R3 should be rewritten to align with the approach taken in NERC Reliability Standard PRC-004-6. Under that Reliability Standard, the entity generates a Corrective Action Plan (CAP) for the identified Protection System component(s) and conducts an evaluation of the CAP's applicability to the entity's other Protection Systems, including other locations. This would replace the second-half portions of the SDT's combined analytical process currently proposed under Requirement R2 and that we suggested removed from the requirement.

4. As proposed, Requirement R4 requires the Generator Owner to provide Corrective Action Plan updates only to the Reliability Coordinator. We believe these updates should be provided to the initial requesting party. Under Requirement R1, that could be a Transmission Operator or a Balancing Authority, as well as a Reliability Coordinator.

5. Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	

Document Name	

Comment
N/A

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3

Likes 0	
Dislikes 0	

Response

Adam Burlock - Adam Burlock On Behalf of: Ashley Scheelar, TransAlta Corporation, 5; - Adam Burlock	
Answer	
Document Name	

Comment
-

Likes 0	
Dislikes 0	

Response

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	
Document Name	

Comment	
TAL understands that the committee was following previous precedent of the 20MVA or greater facilities; however, we believe this standard will create undue hardship on utilities who will be required to meet this standard. 20MVA seems like a low threshold for the size of IBRs. TAL believes the impact of IBRs as small as 20 MVA seems minimal to the integrity of the BES.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	MRO-NSRF_2023-02_PRC-030_UFC_07-03-2024_DRAFT.docx

Comment

The MRO NSRF does not believe that the proposed changes in the thresholds are sufficient.

Requirement R1, as proposed, focuses on changes in active power output, less a few scenarios, which was not the intention of the SAR.

Pursuant to the SAR (emphasis added), § Requested Information, ¶2, “IBRs to ensure that any unexpected ceasing of current injection (partial or full) is analyzed by the applicable Generator Owner and mitigated to the extent possible. NERC has also highlighted that many Generator Owners are not aware of these trips and that the Balancing Authority or Reliability Coordinator may often identify the unexpected or unwarranted tripping issues.”

From the excerpt above it is clear that the proposed standard should focus on trips not caused by balance of plant (BOP) Protection Systems, but trips of the individual generating units. As such, the proposed Requirement R1 language needs to focus on generation resource capability, which is based on availability of individual generating units multiplied by the of individual generating unit’s nameplate. For example, consider a wind generation resource with a 100MW aggregate gross nameplate that consists of 50 2MW individual generating units. When the wind generation resource is at 100% availability, then its capability would be 100MW, regardless of fuel supply. If the wind generation resource had 25 individual generating units trip in a short period of time (≤ 1 minute), the new capability of the wind generation resource is now 50MW. The intention of the SAR was for Generator Owners to analyze these types of events (individual generating unit trips) to determine if performance issues exist, not any change in active power output.

It is not reasonable or practicable to have Generator Owners analyze every change in active power output even with the exclusions outlined in the proposed requirement. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the Proposed Requirement R1.

An additional concern the MRO NSRF has with the four second time frame is that BAL-005-1 R1 specifies a design scan rate of no more than six seconds for acquiring data necessary for calculating ACE and sending to the BA. That is really the defining time frame that is used to setup EMS systems to query BES RTU data. In addition, other entities could have longer scan rates up to 6 seconds. This is also dependent on the communications path and bandwidth available from EMS to the RTU. If a channel has multiple RTU connections on it, then the scan time can vary as it has to be tuned to be able to respond successfully given the bandwidth available to the multiple RTUs on the channel. The MRO NSRF believes that four seconds may be unachievable for some entities and it seems like the four second time should consider BAL-005-1 and an the amount active power changes that occur at an IBR. The MRO NSRF does not believe that amount of precision can actually be achieved the way EMS systems are communicating with BA/RCs today unless some other monitoring mechanism is used.

As such, the MRO NSRF suggest using a 20% change in capability over a one-minute time period to be the threshold for Requirement R1.

· §4. Applicability

The MRO NSRF reiterates its recommendation that the SDT add exclusions to the applicability section of the proposed standard to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection Systems already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. As the proposed standard is currently drafted there is no clear distinguishing language. It is suggested that the footnote information be included in the §4. Applicability to eliminate the footnote altogether.

· Requirement R1:

The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

In R1, suggest the deletion of the word “documented”

In M1, suggest that item 1 be changed from “(1) the documented process...” to “(1) implementation of a process for...”.

With the two changes above deleting “documented”, suggest that item (2) in M1 be deleted.

· Requirement R2:

The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) active power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

The MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

In the new R2.1.3, suggest changing the word “needed” to “indicated” to take into account the possibility of there being no changes available to affect the response of the IBR controls to the system disturbance.

· Requirement R3:

The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, BA & TOP do not need or want this data & analysis.

· Requirement R4.3:

The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit, if the RC, does not need or want this information.

· Requirement R1 & R2

The MRO NSRF would also like to reiterate that most inverter based resources are owned by independent power producers (IPP), as such, it is their best interest to ensure a high availability of the Facility and analyses such as the ones being proposed in PRC-030 are not only in the interest of reliability, but also in the interest of the IPP so long as the criteria for performing an analysis is reasonable and cost effective. The MRO NSRF appreciates the efforts the Standards Drafting Team has put forth and is suggesting the following criteria for the proposed PRC-030 analysis based on the aforementioned information:

Removal of Requirement R1 in its entirety and combining it with the proposed Requirement R2 as follows:

R2. Each applicable Generator Owner, within 120 calendar days of either a, capability1 change of greater than 20% of the generation Facilities gross capability1 nameplate or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a capability1 change of greater than 20% of the generation Facilities gross nameplate capability1, shall, excluding:

· Changes associated with intermittent primary energy source (fuel supply: wind, solar irradiance) availability;

· Resource dispatch, resource ramping, planned outages, or planned resource testing; or

· Loss of Transmission Provider’s interconnection facilities.

2.1. Analyze its IBR facility performance during the event, including:

2.1.1. Determine the root cause(s) of change(s) in capability1;

2.1.2. Document the Facility's Ride-through performance including reactive power response during the event;

2.1.3. Assess any performance issues identified and if corrective actions are needed; and

2.1.4. Determine the susceptibility of its other inverter-based resource facilities to similar events.

2.2. Upon request, provide the analysis results to the requesting applicable Reliability Coordinator, Balancing Authority, or Transmission Operator.

1: A generation resource capability is based on availability of individual generating units that compromise the Facility multiplied by the individual generating unit's nameplate.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

Facilities: 4.2.1. BES inverter-based resources

Consistent with EEI comments, NextEra reccomends removing "elements associated with" from Section 4.2.1

R1

The standard does not provide clarity regarding changes in Real Power output that occur and are restored before a 4 second period. It is unclear whether if corrected within the 4 seconds, the change would need to be collected and reported.

NextEra recommends providing clarity on what is considered a "complete facility loss of output"

NextEra changing language in R1 to "at least 20 MW and at least 20% of the plant's gross nameplate rating". Changing from 10% to 20% as provided in Draft 2 will still provide meaningful data without burdensome reporting.

R3

NextEra raises concerns regarding CAP timeline to resolve within 90 days. Recommend a CAP greater than 90 days.

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	
Document Name	

Comment

ITC has no comments

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Energy Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3

Answer	
Document Name	

Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

R1 requirements
The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out "small active power changes" while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output Δ in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR's, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given Δ across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.

R2 & R3 requirements
The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.

The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is that: "The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity". Additionally it is stated that: "The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed"

The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.
Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.

The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	
Comment	
EEI offers the following additional comment on the proposed 3rd draft of PRC-030-1: • EEI does not support the inclusion of the phrase "The Elements associated with" as contained in the Facilities Section (4.2.1). The inclusion of this phrase expands the scope in ways that are unclear creating unnecessary compliance confusion.	
Likes 0	
Dislikes 0	
Response	

Romel Aquino - Edison International - Southern California Edison Company - 3

Answer	
Document Name	EEI Near Final Draft Comments _ Project 2023-02 PRC-030 Draft 3 __ Rev 0a _ 8_06_2024.docx
Comment	
See comments submitted by the Edison Eclectic Institute in the attached file	
Likes 0	
Dislikes 0	
Response	

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren does not have any additional comments for consideration by the drafting team.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

WEC Energy Group does not agree with the 10% and 20 MW threshold. WEC Energy Group is not satisfied with the SDTs response back to WEC Energy Group in regards to 20MW and 10% threshold. The SDT responded that these values were chosen based on other standards having adopted same values. WEC Energy Group SMEs could not find any other standards that reference these values when it comes to IBR sites. Please name few for reference.

The sample data that was evaluated in the technical rationale document is unreasonable. Selecting Texas region for sample data favors the region with consistent irradiance throughout the year so the same conclusion cannot be applied to the whole US geographical region. If the DT considers evaluating different regions, it will come to a conclusion that there are far more occurrences than what was evaluated for Texas and Hawaii regions. In addition, the DT did not present how long it took to filter through to determine if the events meet R1 or not. WEC Energy Group's concern is not with capturing the event but the administrative burden to filter through to determine if the event meets R1 requirement. Having such a small threshold, the number of events being recorded and evaluated will create unnecessary cost with evaluation effort without significant benefit to BES reliability. Based on submitted comments, other entities have same concerns.

The threshold should be increased to at least 20% gross nameplate AND 20MW.

If DT has concern with applying larger threshold to larger sites, perhaps this can be addressed by applying different thresholds based on Nameplate. For example:

- IBR sites with gross nameplate of 300 MVA or less: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 20% of the plant's gross, and, occurring within a 4 second period
- IBR sites with gross nameplate above 300 MVA: complete facility loss of output, or changes in active Real Power output that are at least 20 MW and at least 10% of the plant's gross, and, occurring within a 4 second period

Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; Tom Schmidt, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	
Document Name	
Comment	
Buckeye supports the comments made by ACES: It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-06 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows: 4.2. Facilities: 4.2.1. Bulk Electric System (BES) IBRs; and 4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

For Requirement R2, 90 days may not be sufficient for determining the root cause analysis when analysis is dependent on information from the Original Equipment Manufacturer (OEM). Southern Company recommends an option to relax the Violation Severity Level if the Geerator Owner (GO) is actively working with the OEM past 90 days to determine the root cause.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	
Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation. Invenergy would like to thank the drafting team for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	

Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Rhonda Jones - Invenergy LLC - 5	
Answer	
Document Name	
Comment	
Can the drafting team please confirm that bullet 3 under R1 includes any activation of a RAS or SPS? If not, a separate bullet should be added to account for RAS/SPS activation. Invenergy would like to thank the drafting team for the opportunity to provide comments.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC signed on to ACES comments: It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-06 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows: 4.2. Facilities: 4.2.1. Bulk Electric System (BES) IBRs; and 4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.	

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

It is the opinion of ACES that the definition of what constitutes an IBR should be consistent across the industry. The Project 2020-06 SDT has been working diligently towards this goal and we do not believe that an individual standard should deviate from their approach. Thus we recommend removing the phrase “The Elements associated with” from section 4.2 and modifying this section as follows:

4.2. Facilities:

4.2.1. Bulk Electric System (BES) IBRs; and

4.2.2. Non-BES IBRs that either have or contribute to an aggregate nameplate capacity of greater than or equal to 20 MVA, connected through a system designed primarily for delivering such capacity to a common point of connection at a voltage greater than or equal to 60 kV.

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,Texas RE,NPCC,SERC,RF, Group Name SRC 2024

Answer	
Document Name	

Comment

In its comments on the preceding posting of this standard, the ISO/RTO Council (IRC) Standards Review Committee (SRC) requested that the reporting requirement in Requirement R2 be expanded to include a report to the RC, BA, TO within three business days of the identification of an event. The SRC reiterates that request here. Although a GO/GOP may not have had adequate time to fully assess and analyze the incident at that point, the degree of the unexpected operation may pose significant risk that an operator may need to be aware of for situational awareness. The operator may have seen an impact on the system that could not be explained without this information. A follow-up report when the incident is fully assessed would still be communicated to the operator(s) for any longer-term considerations.

Also, since “IBR Unit” is not currently proposed to be defined term and Part 4.2.1 of the Applicability section of PRC-030 references “element” data, it is important for the standard to require retention of specific IBR unit information as the applicability of PRC-030 is only down to the “common point of connection” and may not identify specific elements.

Footnote: ERCOT is a party to these comments however does not support the above statement regarding Part 4.2.1.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 3,4,5,6

Answer	
Document Name	

Comment

NCPA is not registered to vote on this item and does not oppose it, however modifications are needed.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

No additional comments

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Except where noted in those comments, ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.

In addition, while ERCOT appreciates the modifications to the Requirement R1 criteria, ERCOT would support modifying the criteria to 20 MW ***OR*** 10% instead of 20 MW **AND** 10%. Inverters/wind turbines/etc. will typically be 1-3 MW in size (with newer technologies approaching 4-5 MW). 10% of a 500 MW facility would be 50 MW and 10% of a 1,000 MW facility would be 100 MW (both of which are present and growing in new Interconnection queues), which are excessive thresholds. One approach to address this issue would be to set both a floor and a ceiling by establishing a threshold of 20 MW **AND** 10% for IBRs with a nameplate capacity of less than 200 MW nameplate and to set a threshold of 20 MW **OR** 10% for IBRs with a nameplate capacity greater than or equal to 200 MW.

ERCOT recommends modifying the third bullet of R1 to be “• A Transmission or collection system loss that***, through normal clearing***, disconnects the IBR generator;” which would better align with the language used in other locations in the standards that describe normal clearing of faults.

Finally, in light of FERC’s directives in its *Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification*, and in light of modifications made by the PRC-029 SDT, ERCOT believes that NERC should be a part of the review process for any instances in which a GO does not implement a CAP as provided in the 2nd bullet of Requirement R3. For informational purposes, the pertinent language from FERC’s Order is provided below (emphasis added).

33. Under Reliability Standard EOP-012-1, a generator owner could explain in a declaration any “technical, commercial, or operational constraints” that preclude its ability to either implement freeze protection measures or implement corrective action plans. However, Reliability Standard EOP-012-1 ***does not define “technical, commercial, or operational constraints,” leaving those terms open to interpretation by each generator owner***. In the February 2023 Order, the Commission approved Reliability Standard EOP-012-1 but ***expressed concern with the uncertainties, ambiguities, and vagueness of the Standard's descriptions of constraints, noting that, without criteria to guide the generator owners or guardrails on what constitutes a legitimate constraint, generator owners may avoid the purpose of the Standard altogether or have declarations without auditable elements***. Thus, the ***Commission directed NERC to address the ambiguity of generator owner-defined declarations by including auditable criteria to ensure that declarations cannot be used to avoid mandatory compliance with the Reliability Standard or obligations in a corrective action plan***.

Likes 0

Dislikes 0

Response

Kyle Thomas - Elevate Energy Consulting - NA - Not Applicable - NA - Not Applicable

Answer

Document Name

Comment

Elevate appreciates the opportunity to comment on the draft NERC standards, particularly those pertaining to future IBR NERC Reliability Standards and FERC Order No. 901 directives.

We support the goals of this standard to analyze and mitigate IBR performance issues; however, the standard as written would require significant analysis of events where IBR facilities respond to grid events *correctly*. This would not be cost effective and not aligned with the intention of the SAR as written. The major driver for this is the trigger criteria defined in Requirement R1. Requirement R1 defines the changes in real power output "occurring within a four-second period." The "within four-second period" characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. It would also pick up all types of dynamic events of an IBR facility, including events where an IBR facility performs correctly. This would lead to detailed forensic event analysis for almost every type of grid event rather than only those events where abnormal performance occurred.

Providing guidance in Requirement R1 for the trigger of the events of concern is a good practice but limiting the requirement language to specify only one trigger (e.g., the "changes in active power output occurring during a period that is no longer than 4 seconds") to capture any type of unexpected changes with an IBR could result in certain types of events being missed while also capturing many events that don't need to be analyzed (e.g., correct/intended responses of an IBR). The recommendation would be to include a set of event triggers as sub-requirements under Requirement R1.

Example triggers could include:

(1) ***Unexpected*** changes in active or reactive power output within a four-second period

(2) ***Unexpected*** changes in active or reactive power output ***longer*** than a four-second period, including momentary cessation, partial or full IBR tripping, or detailed recovery of active power response post-fault

(3) Active or reactive power oscillations that are poorly damped or persist for longer than *[consider value]* seconds

This structure would give the opportunity for additional triggers to be easily added and implemented/considered to more suitably capture unexpected operations occurring from IBRs on the BPS.

If additional trigger criteria are not used, another approach would be to modify the existing "within four-second window" criteria by adding additional SCADA scan rate samples into the existing trigger. Specifically, this would ensure that correctly performing dynamic events would ***not*** be considered within scope, and rather only significant power output changes that are sustained (i.e., trip of an IBR, active power output jump up/down that remains longer than a dynamic event such as momentary cessation or delayed power recovery, etc.). This would align with the language in the SAR to identify IBRs that incorrectly perform during dynamic grid events by either tripping, reducing active power, and not returning to pre-event output levels within 1-second.

Example criteria language for Requirement R1 along these lines could be:

"Changes in active power output that are the greater of either 10% of the plant's gross nameplate

rating, or 20 MW, and the change in real power output remains at the new value for two or more consecutive SCADA scan rates [or could say remains at the new value for 2 seconds or longer]."

In addition, the drafting team should consider modifying Requirement R1 and Requirement R2 so that changes in power output are not limited to just real power, but also reactive power. In fact, Requirement 2.1.2 highlights documentation a facility's ride-through performance including reactive power responses during grid events.

Likes 0	
Dislikes 0	

Response

Bill Zuretti - Electric Power Supply Association - 5

Answer	

Document Name	EPSA FINAL Comments on IBR Standards .pdf
Comment	
Likes 0	
Dislikes 0	
Response	