Comment Report

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 1
Comment Period Start Date:	3/25/2024
Comment Period End Date:	4/18/2024
Associated Ballots:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan IN 1 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 IN 1 ST

There were 66 sets of responses, including comments from approximately 180 different people from approximately 120 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?

2. 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.

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
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
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
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
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	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
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC

					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Scott Berry	Wabash Valley Power Association	3	RF
					Sara Orr	Golden Spread Electric Cooperative, Inc.	5	Texas RE
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC

					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
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
DTE Energy	Patricia Ireland	4		DTE Energy	Patricia Ireland	DTE Energy - Detroit Edison	4	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
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 Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					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
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	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
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC

					Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. Does the entity believe there should be proposed changes in language in regards to Requirement R1 “to identify unexpected changes”?	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA isn’t a GO, however we support the MRO NSRFs feedback:

- Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows “4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.”
- The threshold should simply be a magnitude e.g. 20MVA. Anything less then 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT?
- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within one-minute” time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.

Alternative:

- 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period “The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…”. The MRO NSRF suggests “within 30 seconds” time period. The time period shall start when the first individual generating unit (ibr) is lost. The MRO NSRF suggests reviewing Project 2023-01 EOP-004 IBR Event Reporting, Technical Rationale document for EOP-004-5.
- The MRO NSRF does not agree with Requirement R2 “documented process to identify unexpected changes”. Generator Owners need to analyze “unexpected changes” that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.

Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

On the surface, this seems like a reasonable standard to produce practices surrounding event archiving and heighten reliability from the IBR resources. IBR resources are still in their adolescence and their event interactions with the system are not well understood or foreseen at this time. This raises questions about the timing of these changes. There are also questions surrounding the financial solvency of the current IBR market. Will the market still look the same in 5-10 years? How will these changes impact a market that looks completely different a few years from now?

IPCO strongly encourages NERC to find a way to better address the relationship with the vendor, or Long Term Service Agreement Administrator, to ensure that the entity is only held responsible for those things that is within their control in this process. IPCO understands this is a challenging process to navigate but encourage NERC to draft the standard in a way that recognizes and allows flexibility around time frames dictated in PRC-030.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AZPS supports that following comments that were submitted by EEI on behalf of it's members:

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing "power" with Real Power in order to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, and at least 20 MVA).

5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2).

6. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical:

R1. Each Generator Owner shall implement one or more documented process(es) to capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real Power output that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW, occurring over a two-second period. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such

linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.	
Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	
Answer	No
Document Name	
Comment	
The list provided in the Footnote (1) of the Standard for unexpected power output changes is pretty exhaustive and I can't think of anything to add to it.	
Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
Dislikes 0	
Response	
Anna Todd - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the proposed language in Requirement 1 and doesn't believe there should be changes.	
Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	No
Document Name	
Comment	

The language in R1 of the standard related to the definition of unexpected changes is clear. However, the "two-second" period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.

Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

The power output change monitored should be MW rather than MVA. System voltage transient conditions may drive the reactive output temporarily up or down in exceedance of the criteria thresholds, and monitoring of this regulation response is not the object of this standard drafting effort. All previous system disturbance response evaluations performed by NERC have focused on the MW loss from facilities due to disturbances. The event evaluations prescribed by this draft standard should also focus on unexpected MW changes.

Southern Company recommends that R1 be eliminated and R2 be modified to include the specifics of the process found in R1 in the R2 requirement to implement a process to identify unexpected changes.

The 2-second time frame is quicker than most EMS SCADA polling rates. The EMS SCADA data could miss an event that is longer than two (2) sec, but shorter than the EMS scan rate. Was this time frame selected to not include events where the IBR plant returns to the pre-disturbance condition in less than two (2) seconds?

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	

Please see response in Question 3.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	

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

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term “unexpected changes” adds ambiguity and subjectivity to the requirement and should be removed.

2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.

3. We suggest replacing “power” with Real Power to align with the NERC defined term.

4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA). *****Suggest using 20 MW or 20 MVAr as threshold event triggers, instead of the stated 20% of the plant’s gross nameplate rating or 20 MVA triggers.*****

5. EEI notes that the SAR states that “[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults” yet the proposed Requirement R1 would have IBR GOs capture data on any “unexpected change” on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which seems impractical:

R1. Each Generator Owner shall have a documented process to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 **Loss of a transmission line connecting the IBR or Unit IBR.**

An alternative solution to the above would be to link the capture of IBR telemetry and system alarms to system disturbance events as identified within the Disturbance Monitoring Equipment that will be required at IBR facilities under Project 2021-04 (PRC-028-1). It is EEI's understanding that output triggers could be programmed within this equipment to directly tie drops in Real Power output to system disturbances. This would significantly reduce the requirement for data capture within PRC-030-1.

NAGF COMMENTS

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities. *****It's also our opinion that events which recover within the 2 second timeframe should not require assessment. GOs with large fleets having to assess every response which falls into the 2 second timeframe would result in an enormous effort to review.*****

b. The NAGF requests that the 20MVA threshold be revised to reference MW *****or MVAr***** instead of MVA.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

On behalf of the SERC Generator Working Group:

Suggest eliminating requirement to develop a process and change the threshold levels found in R1 and include that in R2. For R1, suggest changing to MW from MVA so an event isn't triggered on normal voltage swings

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	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	

• PRC-004-6 already covers balance of plant (BOP) Protection System disturbances, so some distinction needs to be provided to direct activities to be completed under PRC-004 and those to be completed under this standard.

• The disturbance threshold should be described in MW, not MVA (20MW not 20 MVA).

o Additional cost to calculate MVA that our controllers do not currently perform.

• The 2-second time period is too short. Most SCADA systems in North America utilize a 2-second or slower scan time. Therefore, it is quite conceivable that events might not be captured with the current SCADA configuration. If the situation rights itself in 2-seconds, then it probably does not need to be studied.

o Any calculations that are required to be added to determine MVA would further increase the time period and make the proposed 2 second time period to fast.

o The disturbance time period should be more like one minute and should commence with the loss of the first generating unit. If it is a genuine issue, then it will last for 60 seconds.	
Likes 0	
Dislikes 0	
Response	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
Answer	Yes
Document Name	
Comment	
In general Vistra agrees with Entergy's comments. We believe the wording is too ambiguous and we would like to see more guidance provided on the expected process. It would help to add more specifics, i.e. "if there is a power output drop during a system disturbance that does not return to pre disturbance levels." We agree that PRC-004-6 already covers most of the collector substation so perhaps PRC-029 should only cover the IBR units? 2 seconds may be too short and the SCADA justification is weak, 30 to 60 seconds may be more be more reasonable.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP recommends footnote 1 be modified to indicate that unexpected changes in power are calculated as the change from the average of multiple power readings for a period of greater than or equal to 0.1 second.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	

Comment	
Black Hills Corporation supports the NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments. BC Hydro suggests that additional clarification may be beneficial on scenarios that could constitute an 'expected change'. A transmission line outage may obfuscate situations where IBRs output unexpectedly drops prior to the line trip, e.g. some Type 4 machines use technology to allow for negative sequence contribution. For a scenario where a windfarm with this technology that doesn't provide negative sequence current during a connecting transmission outage and subsequent transmission line trip – would this be considered an 'unexpected change in generator output' or an 'expected change in generator output'?	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Clarify what the "loss of a Transmission Line connecting the IBR generator" refers to. Does it only refer to the generator lead line? Does it only cover if a generator is on a radial transmission line? The loss of either the generator lead line or a radial transmission line connecting the IBR would result in the disconnection of the IBR and not create any unexpected changes. If the IBR is connected to more than one transmission line, the IBR should not have unexpected changes. An IBR generator should respond to system topology changes as expected through offline studies. Strengthen the standard by expanding R1 to cover events that the RC or TOP identify. This allows for multiple entities to identify events. Also, the RC or TOP can request data from the GO for events (R3) and the GO needs to analyze events pursuant to R3 (R4). Using the gross nameplate rating for a threshold could miss events from large IBRs that are operating at a low output. Change the threshold to be 20% of pre-event MW output.	

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

Generation is typically measured in MW not MVA

Likes 0	
Dislikes 0	

Response

Srinivas Kappagantula - Arevon Energy - 5

Answer	Yes
Document Name	

Comment

Arevon Energy does not support the proposed language for Requirement R1 and provides the following comments for consideration:

1. The 2 second timeframe to identify unexpected changes in power output may not be possible for exiting inverter-based resource (IBR) facilities. The 2 second timeframe is too short. Morst SCADA systems utilize a 2-seconr or slower scan time. Hence, most events might not even be captured within the current SCADA configurations. If the situation rights itself in 2-seconds, then it probably doesnt require to be studied.

2. The disturbance threshold should be described in MW not MVA, most plant owners/operators deal in MW not necessarily talk about a plant in MVA.

3. PRC-004-6 already covers balance of plant (BOP) equipment and related Protection System disturbances. There needs to be some distinction between the activities that need to be performed under PRC-004 and those that this standard is proposing to be studied.

4. R1 is purely administrative in nature and of no reliability benefit. Having a documented process for a performance standard isnt required. Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the SDT should not be including such administrative activities in the proposed PRC-030. A good example is PRC-004, which does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. PRC-030 should align with the approach PRC-004 takes. Essentially delete R1 and make R2 a requirement to identify the unexpected changes in power output.

5. The term "unexpected changes" needs more clarification. While the footnote provides some context, it does not provide enough clarification. For example, the footnote does not include faults. Is the expectation that the GO would document each time the plant reacts to a fault? Arevon Energy recommends removing the footnote and including the criteria under R1 as a list to avoid any ambiguity. The SDT shoudl focus on what should be included in "unexpected changes" rather than simply listing exclusions.

6. The process and activities proposed under Requirement R1 and R2 may better align with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Natalie Johnson - Enel Green Power - 5

Answer	Yes
Document Name	

Comment

Enel North America Inc. (Enel) would like to thank the Standard Drafting Team for their efforts in developing this reliability standard. Enel does not agree with the language in Requirement R1 for the following reasons:

First, a documented process is not necessary for compliance and does not align with similar standards, e.g. PRC-004-6. Enel believes that a documented process for this standard is administrative in nature, does not support reliability, and is needlessly burdensome (NERC's "Paragraph 81" criteria as set forth in 138 FERC ¶ 61,193 at P81 (2012)).

Second, regarding the time-period to identify an applicable event, Enel believes that the two-second period is too short. The technical rationale for the time-period is arbitrary and based on hardware capability rather than industry-accepted standards that establish a minimum scanning rate. Such a short time-period would necessitate storing large amounts of data, i.e. large volume of discrete data points, to be kept for upwards of 45 days, accounting for currently drafted analysis requirements, Requirement R4. Enel would suggest the SDT provide further justification to support the time-period that is reflective of events experienced by IBRs, e.g. Odessa or leverage established industry standards.

Third, the 20 MVA threshold should be changed to align with GADS Event reporting, loss of at least of 20MW of Plant Total Installed Capacity.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	Yes
Document Name	

Comment

Capital Power supports NAGF's comments.

The NAGF does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	Yes
Document Name	

Comment

The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required.

A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Yes. As currently defined in footnote 1, "unexpected changes" appears to include BPS events that an IBR responds to *correctly*. For example, a BPS fault occurs and an IBR dynamically responds to the fault event correctly (within 2 seconds) and the IBR returns back to normal pre-disturbance conditions. As currently written in the standard, this type of response would be deemed an "unexpected change" when in fact it is the expected change/performance for an IBR based on interconnection requirements and facility design. Requiring event analysis, or event just the determination of "expected versus unexpected change" for every single fault event across the entire IBR fleet would result in an exorbitant cost and burden to GOs. Elevate does not believe this is necessarily the perspective or intent of the SDT and therefore wants to stress this technical aspect so that this is clarified for the benefit of all stakeholders.

An example of a change to the "unexpected changes" footnote to address this aspect is detailed below:

"Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, the loss of a Transmission Line connecting the IBR generators, or expected/intended dynamic responses to grid events."

As mentioned, Requirement R1 also defines the unexpected changes in power output "occurring within a two-second period." While the "within two-second period" is being set to capture dynamic, fast-moving events (e.g., fault events, transients, etc.) rather than the slower expected changes like weather patterns/changes, curtailment, ramping, etc. (i.e. the excluded events), we have a concern that the "within two-second period" will catch all dynamic responses of IBRs to any event on the system, including correct/intended dynamic responses (rather than just capturing abnormal or unexpected response). Furthermore, the "within two-second period" characterization may miss controller oscillations, control interactions, and slower active or reactive power responses in the wrong direction than intended. These types of unexpected changes should be identified and analyzed as part of this new standard as well. Examples of industry references and requirements of these types of events include: (a) the IEEE 2800-2022 standard, specifically clause 7.2.2.6 "Restore Output After Voltage Ride-Through", which provides active power recovery time following BPS disturbances in the range of 1.0 second to 10 second; and (b) the NERC Reliability Guideline for BPS-Connected IBR Performance provides information on IBR responses occurring longer than two-seconds such as automatic return to service following a trip.

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 "unexpected changes in power output occurring with a two-second period") to capture any type of unexpected changes with an IBR will likely result in many 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 two-second period*

(2) unexpected changes in active or reactive power output longer than a two-second period, including momentary cessations and tripping of the IBR plant or individual IBR units.

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

*Note: This is incumbent on the recommended change to "unexpected change" footnote that excludes the *expected* response to grid events.

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.

Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren believes the threshold in R1 is too low and suggests changing it to 75 MVA to align with PRC-004. We also suggest inserting the phrase "related to a common cause" in the footnote after the word "generation." We also think R3 should be removed as it is redundant with reporting requirements in MOD-032. The new Category 2 registration also creates redundancy within the standard. In the Facilities sections, we believe Bulk Power System should be changed to Bulk Electric System because this term is used more frequently and is better understood. We also think event detection would be too burdensome with the current requirements in R1. Finally, if an IBR is on the Distribution system, is that part of the BPS? In general, Ameren also agrees with EEI's and NAGF's comments.	
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 provides the following feedback: • Need to ensure that PRC-030 R1 does not include balance of plant (BOP) Protection System already covered under PRC-004-6. An example would be PV & wind generation 34.5kV collection system Protection Systems. This should be addressed in the §4. Applicability as follows "4.2.1. the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition." MRO NSRF requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6. • The threshold should simply be a magnitude e.g. 20MVA. Anything less than 20MVA would not affect the Bulk Electrical System pursuant to the definition and is the accepted threshold within industry. This would also more closely align with GADS Event reporting thresholds. In addition, the MRO NSRF would like to understand the justification of why apparent power is the magnitude being used by the SDT? • 2 second time period. The MRO NSRF does not agree with the rationale for 2s time period "The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…". The MRO NSRF suggests "within one-minute" time period. The time period shall start when the first individual generating unit is lost. This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis. • The MRO NSRF does not agree with Requirement R1 "documented process to identify unexpected changes". Generator Owners need to analyze "unexpected changes" that meet a threshold. Having a process is unnecessary, not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit.	
Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the concerns expressed in the EEI comments for this question.	
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	Yes
Document Name	
Comment	

PG&E agrees with the NAGF position in which it does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 “shall have a documented process” is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

Likes 0	
Dislikes 0	
Response	

Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM agrees with EEI's comments	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation recommends additional language in R1 requirement to add “ occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX , and is greater” to add flexibility to the requirement. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes
Document Name	
Comment	
The language in R1 of the standard related to the definition of unexpected changes is clear. However, the “two-second” period requires additional definition before we can implement appropriate detective controls. We assume that this time period refers to two-second intervals rather than any two-second span, or is this up to each entity to determine? We would appreciate clarification prior to submittal for board approval.	

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

- MH requests that the SDT clearly articulate what equipment is within scope for this standard, with special attention paid to any potential overlaps with PRC-030 and PRC-004-6.
- MH suggests modifying the R1 to read "Each applicable Generator Owner shall have a documented process to identify unexpected changes1 in power output occurring within a **60-**second period **as result of system disturbance event(s)** and is the greater of either 20% of the plant's gross nameplate rating, or 20 MVA.
- 2 second time period. The MH does not agree with the rationale for 2s time period "The two second time period, the fastest Supervisory Control and Data Acquisition (SCADA) scanning rate…". The MH suggests "within 60-seconds" time period. The time period shall start when the first individual generating unit is lost or reduced as result of system event(s). This aligns with the time-frame traditionally used and this ensure that the events that need to be analyzed are captured without having multiple events or over analysis.

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

In addition to listing event causes that need not be identified in footnote 1, it may be easier for R1 to specify the types of events that should be screened for further analysis. For example, R1 could require identification of 20 MW/20% drops in output within two seconds due to "unexpected behavior of generator settings and controls," or similar language. The Standard could also GADS forced outage cause codes to clarify which types of outages are to be identified and which are not to be identified. A major concern is that, without greater clarity on the type of events that are to be identified, manually reviewing all events to exclude the event types discussed in the footnote will create a huge compliance burden. For example, the passage of clouds over small to medium solar plants can cause changes in output of 75% of nameplate capacity per second,[1] so the generator operator needs a way to automatically exclude those events from consideration by having greater clarity on the types of events that are to be screened for.

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

Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments:

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase “unexpected changes” is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

“encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode.”

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).
- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called “droop control”).
    - The resulting change in power output is a full 5% step change resulting in a final output of 456.75 MW and 20 MVAR (457.2 MVA).
- The change in apparent power in under 2 seconds is 21.7 MVA.
    - While this is less than 20% of the unit’s gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

Thus, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immateria to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES’ opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

“Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2.

1.1 Occurs within a 30-second period and

1.2 Greater than either (whichever is larger):

1.2.1 20% of the IBR's Normal Rating or

1.2.2 20 megawatts (MW)"

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 Edison Electric Institute (EEI), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1

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

The Standards Drafting Team (SDT) needs to ensure that the proposed new Reliability Standard PRC-030-1 does not overlap with the purpose and requirements of PRC-004-6 - Protection System Misoperation Identification and Correction, in which the "unexpected changes in power output" of an IBR are not attributable to a protection system operation or misoperation. This could be accomplished by revising Footnote 1 to state,

"Unexpected changes in power output includes any change of generation that is not attributed to factors such as weather patterns, change of wind, change in irradiance, curtailment, ramping, planned outage, planned testing, *protection system operation*, or the loss of a Transmission Line connecting the IBR generators".

In addition, Requirement R1 limits the identification of unexpected power changes to those “occurring within a two-second period” and does not consider slower, unanticipated IBR control system interactions that may cause power oscillations. Two seconds is not long enough for average SCADA systems to quantify the unexpected power changes.

SMUD recommends that the time period be increased to “a 60-second period” to allow for greater detection of unanticipated IBR control system interactions that affect the Bulk Electric System.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	Yes
Document Name	

Comment

Constellation recommends additional language in R1 requirement to add “ occurring withing two-second period or the minimum possible evaluation period with the existing site equipment, not to exceed XXX , and is greater” to add flexibility to the requirement.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 does not support the proposed language for Requirement R1 and provides the following comments for consideration:

a. The 2 second timeframe to identify unexpected changes in power output may not be possible for existing inverter-based resource (IBR) facilities.

b. The NAGF requests that the 20MVA threshold be revised to reference MW instead of MVA. As currently drafted, there does not appear to be any value gained from having to calculate the MVA before doing any analysis.

c. The NAGF notes that PRC-004: Protection System Misoperation Identification and Correction does not require a documented process to identify misoperations, rather it requires applicable registered entities to identify misoperations and take actions accordingly. Therefore, the NAGF recommends that the proposed PRC-030 Requirement R1 be deleted or modified to align with PRC-004.

d. The NAGF notes that Requirement R1 "shall have a documented process" is purely an administrative documentation effort that provides no benefit to reliability. Note that Paragraph 81 efforts eliminated such administrative burdens from the NERC Reliability Standards and as such the DT should not be including such administrative activities in the proposed PRC-030.

e. Recommend moving footnote #1 – unexpected changes in output criteria as items listed under Requirement R1.

f. The NAGF notes that the process and activities proposed under Requirement R1 and R2 better aligns with Generator Operator (GOP) responsibilities rather than Generator Owner (GO).

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 does not agree with the 20% or 20 MVA threshold. The technical rationale states that "was chosen to be large enough to screen out normal operational events but not so large that it does not detect events that should be analyzed". We do not agree that it is large enough to screen out normal events. The SAR discusses "misoperations" due to grid disturbances. The thresholds in R1 would capture more events than misoperations due to grid disturbances.

WEC Energy Group proposes that the threshold should be set to at least 75% of the site nameplate for BES IBRs and 20 MVA for Non-BES IBRs to only capture site misoperations/faults. The loss of generation in past disturbances was largely contributed by sensitive IBR trip protection settings and impacted the entire site. The disturbance reports clearly support that R1 should state and mandate evaluation for site misoperations/faults based on thresholds or system disturbance identified by TP, PC, RC, or TO.

In addition, as it's currently proposed, the requirement of R1 will be difficult to identify. Logic that's necessary to filter out "unexpected changes" attributed to weather patterns, change of wind and/or change in irradiance factors will be difficult to develop and costly.

The "unexpected changes" attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

SRP feels that it may be appropriate for this requirement to apply to all generators larger than 20 MVA, not just IBRs. Unexpected power swings on all generators need to be explored and mitigated as the risk to each interconnection is similar. SRP's suggestion is to remove BPS IBR facility verbiage in the facilities portion of the applicability section or add language to include all units. SRP also recommends the standard title be changed to Unexpected Power Output Event Mitigation. Lastly, SRP would like Out of Management Control (OMC) to the factors of power output changes in Note 1.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

WECC suggests that the SDT should emphasize language to ensure that MVAR support, if lost, is captured as an event as “power output” may be interpreted as simply MWs.WECC also believes the SDT should use the proposed definition of Inverter-Based Resource and not add terms (e.g., IBR “generator”). Note that Project 2023-01 EOP-004 describes power output loss differently and limits it to MW—"The Responsible Entity is not required to report losses due to weather patterns, lack of wind, change in irradiance, fuel unavailability, curtailment, ramping, planned outage, planned testing, failure of SCADA or Telemetering data, or due to the loss of a radial transmission facility that disconnects the IBR generators. WECC believe the SDTs should collaborate and use same language to describe conditions and criteria.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon supports the concerns expressed in the EEI comments for this question.

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	

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

Answer	Yes
Document Name	
Comment	

Electric Reliability Council of Texas, Inc. (ERCOT) recommends that the threshold for what constitutes an unexpected change under Requirement R1 be modified to be the ***lesser*** of either 20% of the plant's gross nameplate rating, or 20 ***MW***. This would ensure that units with a rating larger than 100 MW would assess events down to 20 MW. The 20% threshold would set the floor for units with a rating of less than 100 MW, which would be appropriate. Under the currently proposed language for Requirement R1, a 500 MW plant would not be required to analyze a 90 MW unexpected change, which is a change that is larger than the full rating of some entire units. This outcome would not be consistent with the objectives of the standard.

ERCOT recommends that MW be used as the unit of measurement instead of MVA because MVA includes both real and reactive power. Most IBRs operate in reactive priority mode, which means that MVAR will adjust as needed during the two-second window to support voltage, which may skew any MVA-based measurements. Most ride-through performance failure issues are related to unnecessary tripping of the IBR plant or units or abnormal reduction in active current during the ride-through, both of which would result in unexpected changes in MW output. If the SDT believes unexpected changes in MVAR output should also be assessed, ERCOT recommends that this be addressed separately in a dedicated Requirement with its own criteria to avoid confusion or misapplication.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EEI does not support the proposed language in Requirement R1 due to the following concerns:

1. The use of the term "unexpected changes" adds ambiguity and subjectivity to the requirement and should be removed.
2. The use of footnotes places clarifying information outside of the requirement and should be brought directly into Requirement R1.
3. We suggest replacing "power" with Real Power in order to align with the NERC defined term.
4. EEI asks that the SDT provide some justification for the proposed event trigger (i.e., greater of either 20% of the plant's gross nameplate rating, or 20 MVA).
5. We suggest combining Requirements R1 with R2, similar to other NERC Reliability Standards, in order to negate the need to have a requirement that requires an entity to document a process (R1) and another to implement that process (R2).
6. EEI notes that the SAR states that "[m]ultiple NERC disturbance reports have identified the undesired performance of bulk power system (BPS) connected inverter-based resources (IBRs) during grid faults" yet the proposed Requirement R1 would have IBR GOs capture data on any "unexpected change" on IBR power output. While a laundry list of exclusions is provided, IBR GOs will still have to capture and analyze any event that meets the criteria of R1 and determine why the drop in power output occurred and then save all of the event data except those events that meet the identified exclusions. If left unchanged this will result in a substantial new burden on IBR owners to collect and analyze significant amounts of data that in many cases will not be relatable to any system faults. Necessitating more staff and unrecoverable costs to support this effort, while not achieving the desired improvement in BPS Reliability.

While EEI offers the following as clearer language for what has been proposed for Requirement R1, we note that a Requirement such as proposed or aligned with our proposed changes will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical (See proposed changes below):

R1. Each Generator Owner shall **implement one or more** documented process**(es)** to **capture and retain IBR system telemetry and IBR alarms data necessary for analyzing IBR performance during IBR or Unit IBR events where there is a decrease in Real** Power output **that is equal to or greater than 20% of the power output of the IBR or IBR Unit, but not less than 20MW,** occurring over a two-second period**. IBR and Unit IBR telemetry and alarm data captured during a specified IBR or Unit IBR event, determined by the responsible IBR GO, to have been the result of one of the following conditions negates the need for the IBR GO to retain the captured data:** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Losses in IBR or Unit IBR associated with weather, such as changes in wind, solar irradiance, etc.; or

1.2 Load curtailments, resource ramping, planned outages, planned resource testing; or

1.3 Loss of a transmission line connecting the IBR or Unit IBR.

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes

Document Name	
Comment	

Having a documented process for a performance standard is not required and is purely administrative. PRC-030 should follow PRC-004 which does not require a documented process.

The window of "occurring within a two-second period" should be modified to calculate an average of multiple power readings over a longer period.

The threshold should be described in MW instead of MVA.

The term “unexpected changes” needs more clarification and the criteria should be listed as part of the requirement instead of a footnote.

Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee’s comments:

"The footnote describing what are not “unexpected changes” does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) “unexpected change” events by simply regulating voltage, as planned, and required.

A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions."

Likes 0	
Dislikes 0	
Response	

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	
Comment	

Invenergy believes additional language is needed to ensure no overlap of requirements between PRC-004-6 and PRC-030-1. Additionally, to reduce administrative burdens and better align with the language of other like standards, the documented process language should be removed and R2 should be deleted.

As currently drafted, R1 requires all data be resolute down to a 2-second or faster interval in order to accurately identify events and filter out events like those detailed in footnote 1. Not all sources of data are capable of being reported at these intervals and the proposed interval could result in inaccurate analysis, over-reporting, and data storage issues.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Yes, TEPC agrees with EEI's comments regarding 'to identify unexpected changes' should be removed.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	Yes
Document Name	

Comment

Avista fully supports PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI’s comments and support the changes suggested in those comments.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes

Document Name	
Comment	

We agree with EEI's comments and support the changes suggested in those comments.

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	

ACES appreciates the effort put forth by the SDT in drafting the newly proposed PRC-030-1 Reliability Standard. Crafting an entirely new standard is no small undertaking and we are grateful for the hard work and dedication of the SDT members. ACES believes that draft 1 is an excellent step towards meeting the requirements of FERC Order 901; however we contend that the current language would benefit from a few modifications.

From a historical perspective, the Reliability Standards have used MVA to classify generating units and to establish a threshold for applicability. Megawatts (MW) is typically used to quantify the changes in generation output and load (e.g., Most Severe Single Contingency, Reporting ACE, EOP-004, MOD-031, CIP-002 Impact Rating, etc.). It is the opinion of ACES that it would be best for PRC-030-1 to conform to the established convention and utilize MW in lieu of MVA when identifying these event types.

Additionally, it is the opinion of ACES that the phrase "unexpected changes" is overly broad so as to capture what is arguably an edge case scenario. Per the Technical Rationale, the intent of the SDT was to:

"encompass both unexpected decreases (i.e., loss) and unexpected increases (i.e., additions) that may be caused by IBR mis-operations that could affect system reliability. For instance, a battery energy storage system that mis-measures system frequency may unexpectedly enter a charging mode."

It is our position that the greater risk to the reliability of the BES is from an unexpected decrease in generation not an unexpected increase. We do acknowledge that unexpected increases in generation may also pose a reliability risk to the BES; however, we contend that this has always been the case for all generation types and the incidence rate is statistically insignificant. Using a modified version of the example provided by the SDT in the portion of the Technical Rationale quoted above, please consider the following hypothetical scenario:

- A pumped storage hydro generating unit with a gross nameplate rating of 480 MVA is operating with an active output of 435 MW and 20 MVAR (435.5 MVA).
- During a control system malfunction event, the control system incorrectly calculated system frequency sending an incorrect frequency response signal causing the unit to exhibit a near instantaneous change in power output (note: this control action is commonly called "droop control").
    - The response to an erroneous frequency reading results in a near instantaneous change in power output to 456.75 MW and 20 MVAR (457.2 MVA).
    - The resulting change in apparent power in under 2 seconds is 21.7 MVA.
        - While this is less than 20% of the unit's gross nameplate rating, it is greater than the minimum 20 MVA threshold specified in PRC-030-1 R1.

In summary, as is illustrated in the hypothetical example above, it is our assertion that the risk to the BES from an unexpected increase of 20 MVA is immaterial to the generating resource type that caused said increase. In short, we believe that this standard should remain focused only on sudden, unexpected losses caused by IBRs at this time. We believe this approach would more closely align with PRC-004-6.

Lastly, it is ACES' opinion that the parameters identifying these types of events should be modified to more closely align with the language used in the most recent revision of EOP-004-5. Therefore, we recommend that R2 be struck in its entirety and R1 be modified to use the following language:

"Each Generator Owner that identifies an unexpected loss of aggregated Electrical Energy output at an applicable facility (per Section 4.2) shall, within 120 calendar days, determine if the unexpected loss meets the criteria identified in Part 1.1 and Part 1.2.

1.1 Occurs within a 30-second period and

1.2 Greater than either (whichever is larger):

1.2.1 20% of the IBR's Normal Rating or

1.2.2 20 megawatts (MW)"

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Ruchi Shah - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	
Document Name	
Comment	
The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Since PRC-030-1 applies to all BES and non-BES connected resources, Texas RE recommends revising section A 4.2.2 Facilities to the following: 4.2. Facilities: 4.2.1. Bulk Power Electric System (BPS BES) Inverter-Based Resources (IBR) 4.2.2. Non-Bulk Electric System (Non-BES) Inverter-Based Resources (IBR)	

This change would make PRC-030-1 consistent with PRC-028-1 and PRC-024-4 which reference BES and non-BES Inverter-Based Resources.

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

The footnote describing what are not "unexpected changes" does not consider small (<5%) system voltages changes caused by shunt reactor or capacitor switching. This means, an IBR plant operating at constant MW (low wind conditions or vars at standstill) but regulating voltage could generate frequent (daily) "unexpected change" events by simply regulating voltage, as planned, and required. A MW requirement instead of MVA would allow to remove all the unwanted error reporting linked to voltage regulation, especially during continuous operating conditions.

Likes 0	
Dislikes 0	

Response

2. 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.

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

Answer	No
Document Name	

Comment

Allowing the PC or RC to lengthen the two-second period in Requirement R1 may be consistent with the objectives of the standard. There may be instances, such as weak grid or other stability needs, in which slower responses slightly beyond 2 seconds would be required. There may also be other varieties of exemptions. This may also provide a mechanism to account for documented performance characteristics that would not require analysis. This could be addressed by adding the following sentence to footnote one: "Unexpected changes would not include performance that is expected as part of documented RC-, PC-, TP-, or TOP-approved tuning or exemptions."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Please see response in Question 3.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	

Response

Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1

Answer	No
Document Name	

Comment

The data capturing requirements are minimal in technical terms and wouldn't require the installation of additional monitoring equipment at a standard IBR installation; most of the compliance effort would be procedural and would be performed regardless by the PUD as part of its regular system disturbance analysis tasks.

Likes 1	Snohomish County PUD No. 1, 3, Chaney Holly
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

PG&E does not have any alternatives for more cost-effective options.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
At this time, with unclear direction of intent of responsibility, FirstEnergy cannot determine the cost effectiveness of these proposals.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
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	
Ruchi Shah - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
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	
David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers	
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	Yes
Document Name	
Comment	
It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.	
Likes 0	
Dislikes 0	
Response	
Colin Chilcoat - Invenergy LLC - 6	
Answer	Yes
Document Name	
Comment	
Regarding alternatives and cost-effectiveness, Invenergy has concerns that there is a significant degree of redundancy, and in some instances even conflicts, between the proposed requirements and project goals in PRC-028-1, PRC-029-1, and PRC-030-1. These projects should be aligned to ensure applicable entities do not face duplicative or conflicting requirements.	
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	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
SRP feels that there could be many alternative and more cost-effective options, so it may be prudent for the drafting team to present some alternatives addressing the FERC Order recommendations for SRP to weigh in.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
The “unexpected changes” attributed to weather patterns, change of wind and/or change in irradiance factors occur on a daily basis in some geographical regions, often multiple times per day and can easily drop the site output by 20MVA. It will be labor intensive to look at each 20MVA drop event and determine if it’s related to unexpected changes unrelated to weather factors. The more cost-effective option is to limit the evaluation to misoperations/faults and if identified by TP, PC, RC, or TO.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	

Please reference all the NAGF comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation supports the NAGF comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the GO facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering or softening of the transmission system abnormal condition's impact on generating facilities, where very sensitive electronic controls are used, would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on IBR based GO facilities.	
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 North American Generator Forum (NAGF) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

Likes 0	
Dislikes 0	

Response

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

Comment
PRC-030 overlaps with PRC-029 that the SDTs should consider combining some requirements of PRC-030 into PRC-029

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	

Comment
AEPC signed on to ACES comments: It is the opinion of ACES that, as written, PRC-030-1 is not a cost-effective approach. Requiring the GO to identify any unexpected changes in power output occurring within 2 seconds will place an undue compliance burden on the GO. This is particularly true when said power output is measured in MVA. As most facilities monitor output in MW, including MVA will require the GO to either add additional monitoring capabilities or modify existing monitoring equipment to monitor an additional parameter(s). Additionally, requiring the GO to create and maintain a documented procedure as is done in R1, will increase the compliance risk of the GO with no appreciable reduction in risk to the BES. It is ACES' opinion that PRC-030-1 should be modeled after PRC-004-6 by merely requiring the GO to identify applicable event types and allowing the GO the flexibility to perform this task as it sees fit.

Likes 0	
Dislikes 0	

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

1. The Drafting Team should add a requirement to R3 that the 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.

2. In the draft, R4 and R5 specify that the GO has 45 days to complete its analysis report and then another 45 days to develop a Corrective Action Plan (CAP). This is not enough time in many cases, particularly for complex events or truly unexpected generator behavior, analysis of which is likely to present the greatest reliability value. Analyzing events in which a resource failed to ride-through a disturbance is likely to require consultation and coordination with the equipment manufacturer and project engineer, which requires significant time. Reliability would benefit if the time requirements were extended to a more reasonable period, such as 120 days for analysis and then 60 days for developing a CAP.

3. R1 and R2 could be combined and streamlined to remove the administrative and procedural requirements for having a documented process for identifying events, and instead simply require the GO to demonstrate compliance by showing that it has identified and analyzed the events it was supposed to.

Likes 0	
Dislikes 0	
Response	
Patricia Ireland - DTE Energy - 4, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	

The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and, especially for very small geneating units, not cost-effective compared to the benefit derived.

We suggest incorporating into the standard a deminimus capacity rating excluding smaller generators from the scope of this standard.

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	Yes

Document Name	
Comment	
The requirement to investigate each two-second 20% (or 20 MVA) drop in power output to determine if the drop meets the definition of an “unexpected change” for all NERC regulated IBRs is burdensome and not cost-effective for any benefit derived. We suggest a deminimus capacity rating that excludes smaller contributors from the scope of this standard.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation supports NAGF comments Kimberly Turco 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	
As proposed, the MRO NSRF does not believe that this is cost-effective. Please see all MRO NSRF comments. Additionally, the source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.	

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI supports comments provided by the NAGF.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

As described in AZPSs response to question 1 above, the Requirement as proposed will be very costly and burdensome to IBR GOs. Moreover, the only way to minimize the burden of capturing this data would be to tie these events to system disturbances, which is the root cause of IBR aberrant performance but would require GOs to have ready access to system disturbance information, which may be impractical:

To address the issue of system disturbance identification within IBR control systems, identified above, the SDT should coordinate with the Project 2021-04 (PRC-028-1) SDT to determine whether Disturbance Monitoring Equipment that will be required under that project could provide triggers into IBR control systems so that IBR Telemetry and IBR system alarms could be efficiently linked with disturbance event seen at IBR facilities. Such linkage, if feasible, would minimize IBR GO data collection, as well as provide useful information that would assist IBR GOs in understanding the impact of disturbances on their equipment while improving their ability to develop Requirement R5 CAPs that efficiently resolve performance issues.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	Yes

Document Name	
Comment	
Please reference all the comments provided on this comment form for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Natalie Johnson - Enel Green Power - 5	
Answer	Yes
Document Name	
Comment	
It is difficult for the industry to determine the full cost implications of PRC-030. It is premature to determine at this time the cost implications until it is fully known what is involved in the analysis of IBR loss events following grid disturbances.	
Likes 0	
Dislikes 0	
Response	
Srinivas Kappagantula - Arevon Energy - 5	
Answer	Yes
Document Name	
Comment	
Please refer to the comments provided by North American Generation Forum (NAGF) for possible cost-efficiencies.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

IPCO wants to highlight one of the biggest gaps not being addressed with these proposed changes: Utilities are dependent on contractors and can only hold those contractors to contractual terms. When those contractors are outside of NERC jurisdictional authority, the entities can only do some much, outside of their contracts, to make contractors comply and produce evidence. The standards and requirements must be written in ways that allow for entities to be able to comply until there is some level of authority to bring the contractors into the sphere of the NERC jurisdiction. These changes do not address that concern.

IPCO encourages improvements that encompass the parts of the relationship with the vendor or Long-Term Service Agreement administrator that the entity can control other than just through contractual means. Relying on a contractor for time-based responses presents challenges if not addressed in this draft.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

WAPA isn't a GO, however we support the MRO NSRFs feedback:

As proposed, the MRO NSRF does not believe that this cost-effective. Please see all MRO NSRF comments. Additionally, The source and impact of the system transients should be evaluated and remedied in addition to or rather than focusing only on the Generator Owner (GO) facility reaction to the non-normal system conditions. A reduction of or complete elimination in the source of the disturbances is in order. Any buffering of softening of the transmission system abnormal condition's impact on generating facilities where very sensitive electronic controls are used would improve GO facility reaction to the disturbances. Adequate transmission system voltage support equipment in weak support areas could lessen the impact of disturbances on ibr based GO facilities.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
No comment. Too new and early to determine cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
no comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	
Document Name	
Comment	
TEPC agrees with EEI's comment, unkowing the outcome of this newly developed Standard, we do not have a response at this time.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
NIPSCO will not comment on cost effectiveness but please see responses to questions 1 and question 3 for recommendations.	
Likes 0	
Dislikes 0	
Response	

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

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy will not submit any input on the cost effectiveness of this newly developed Reliability Standard.	
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	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM has not researched alteratives therefore, cannot comment on more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
No 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 cost effectiveness.

Likes 0	
Dislikes 0	

Response
Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment
This is too broad of a question and does not pertain to PRC-030-1.

Likes 0	
Dislikes 0	

Response

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

Brian Lindsey - Entergy - 1

Answer	
Document Name	

Comment

• Inverter-Based Resources (IBR) is capitalized but not yet defined.

• R5.2. Does not add any value.

• Propose a 5-year phased in implementation plan to give adequate time for the GO to implement effective procedures.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

MRO is voting Negative on the changes to PRC-030-1 because the proposed language in R5.1 was ambiguous regarding which parts of R4 needed to be addressed in the CAP (we understand that the R5.1 CAP is intended to address both R4.1 and R4.2). This ambiguity could cause problems with enforcing R5.

Likes 0	
Dislikes 0	

Response

David Vickers - David Vickers On Behalf of: Daniel Roethemeyer, Vistra Energy, 5; - David Vickers

Answer	
Document Name	

Comment

Requirement R4: We would prefer to see 120 days which would match PRC-004 but maybe a fair compromise is 90 days. It takes time to collect all the information in some cases since it may require consulting with inverter or PPC OEMs. The requirements for notification would need to be better defined in our opinion.

Requirement R5: same comment on time as R4.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5	
Answer	
Document Name	

Comment

While the scope and general intent of PRC-030 appears reasonable, AEP believes its process and flow is flawed and needs to be changed. Firstly, as currently proposed, the standard process seems to include R1, R2 and R4 within 45 days of an Event which would also include cause identification. This is overly optimistic, especially in those cases where OEM support and insight will be needed, and thus it would be unreasonable to achieve this in all cases. Furthermore, R4 and R5 should both align with the PRC-004 requirements and timeframes so that both standards are consistent with one another. It is not logical to mandate “cause identification” within 45 days (or any time frame for that matter) before the root cause is even determined. While it might be reasonable to simply identify the “event” within 45 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 45 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 (R4.2) of that CAP to other facilities. Applicability cannot be documented without first determining the root cause and then the CAP.

The standard infers that it is already “understood” that a qualifying event has occurred and been classified accordingly. As a result, there is no clear establishment of when the clock actually starts on the process.

AEP recommends that there should be a maximum time frame identified for a GO to “identify” that an “applicable Event” has occurred. The standard seems to imply that this will be done per R1/R2 within 45 days of the Event occurring or within 45 days of receiving an R3 data request. PRC-004, by contrast, allows 120 days to identify if an operation was proper, or instead, was a misoperation.

The notification obligations in R4.3 should not be handled within PRC-030, and instead, should be done as routine data requests, perhaps using the NERC Section 1600 data request process or similar.

R4.3 includes the phrase “Notification to each applicable Balancing Authority, Reliability Coordinator, *or* Transmission Operator of the analysis results.” Did the SDT perhaps intend that “and” be used instead of the “or” to require that *all* of them be notified? Similarly, R5 and R6 only require the RC to be notified, and we recommend that the Balancing Authority and Transmission Operator be added to those requirements as well.

R3’s data request turnaround time of “within 30 calendar days” should be changed to be twenty calendar days to align with that of R7 in PRC-028. In addition, R3 appears to be a potential double-jeopardy issue with PRC-028 R7 data requests. This is further confused by using the generic word “data” in R3. AEP requests that specificity be provided to make it clear exactly what this data *is* and is-*not*, and to specifically note it would not include data required in PRC-028. AEP would suggest going even further, ideally, by simply deleting R3 in its entirety, thereby eliminating any possibilities of double jeopardy by simultaneously violating multiple standards.

Implementation Plan: AEP has no objections for the implementation period to be six months for purposes of identification, however a separate implementation period needs to be established for those cases where field equipment changes are necessary. This is greater than simply a “configuration issue”, as new equipment may be needed to obtain additional data points. AEP recommends that a period of two calendar years be allowed instead to accomplish whatever field changes may be necessary.

The requirements proposed in PRC-030 clearly and appropriately make the GO responsible for the performance of the Invertor-Based Resources and

IBR units it owns. AEP recommends the SDTs for PRC-028, PRC-029 and PRC-030 review their proposed standard obligations to ensure there is a consistent, integrated plan across these projects and standards to achieve the goal of correcting the past performance of Invertor-Based Resources and IBR units. Having a coherent strategy document that explains how these three standards complement each other (and not be duplicative) would be beneficial.

AEP does not believe that the Operations Planning time horizon is most appropriate for these requirements. Instead, please consider using the "Operations Assessment."

VSLs: The row for R3 does not have an additional column or gradient related to the 30 day requirement. AEP recommends adding an additional column for cases where data is provided but done so in excess of the 30 day threshold. As a result, AEP has chosen to vote "Negative Opinion" on the non-binding poll.

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 supports the additional comments provided by both NAGF and EEI.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments.

1. The Applicability section (A.4.2 Facilities) references BPS IBR. BC Hydro suggests that the Facilities section instead use wording reflective of the proposed Category 2 GO as included in the recent revisions to the NERC Rules of Procedure.
2. Requirements R1 through R6 reference "Each applicable GO". BC Hydro suggests that the use of "applicable" is redundant once the Section 4 Applicability is updated to reference Category 2 GOs.
3. Requirements R3 as drafted will obligate a GO to provide data to its BA, TOP, or RC regardless of an R1 qualified event occurring (e.g. identification of an unexpected change per R1). The Rationale for Requirement R3 section of the Technical Rationale references "allowing BAs, RCs, and TOPs flexibility to determine thresholds". BC Hydro suggests that additional clarity is required on the "abnormal performance issues" and vis-a-vis the "thresholds" and "methods" that BAs, RCs, and TOPs may adapt to suit their specific needs as indicated in the

Technical Rationale. BC Hydro requests that the drafting team clarifies whether the intent behind R3 is to expand of scope beyond the R1 unexpected changes criteria, or to only allow the BA, TOP, or RC to obtain data on R1 events potentially missed by the GO.

4. Requirement R5 appears to assume a zero defect R1 process, i.e. any unexpected change is due to inadequate performance (e.g. misoperation), and a CAP will be necessary for each R2 event. BC Hydro requests that the drafting team provides additional clarity on this expectation as there may be other factors, extrinsic to the IBR performance against design or operational circumstances, that could potentially lead to meeting the R1 threshold and which may not warrant a CAP.
5. The timeline in Requirement R5 is expressed in "days". BC Hydro recommends that the wording be revised to clarify whether it is business or calendar days.
6. BC Hydro recommends that the required analysis timelines be brought into alignment with PRC-004 timelines. These timelines are more reflective of the expected workload associated with obtaining and processing the IBR performance data, and there will likely be additional implementation and sustainment benefits by leveraging existing PRC-004 processes.
7. Requirement R6 Part 6.3 does not include a timeline to notify the RC(s) upon meeting a specified trigger (CAP changes or CAP completion.) Also, the Part 6.3 requirement to notify is not reflected in the VSL Table.
8. The Measures (e.g. M1, M4) include the wording: "Evidence may include, but is not limited to:" followed by an "and" enumeration. Is the intent of the drafting team to set a minimum expectation that all the numbered items must be produced as evidence of compliance, e.g. for Requirement R1 the compliance evidence must include at a minimum (1) a documented process, (2) data recordings AND (3) gross nameplate rating?
9. For Measure M1 BC Hydro suggests that "actual data recordings" may not constitute adequate evidence to substantiate the existence of a documented process, and recommends removing it.
10. BC Hydro suggests that the use of "shall" in the language of the Measures may not be appropriate as it could imply a new Requirement or expansion on the existing Requirement. The obligation of having evidence is adequately established and enforceable via the CMEP.
11. BC Hydro recommends that the implementation plan for PRC-030-1 be coordinated with the approval of the approval of the IBR and IBR Unit definitions.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

WAPA isn't a GO, however we support the MRO NSRFs feedback:

- §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP?
- Time frames in R3 & R4 do not align.
  - Within 30 days supply data for the "identified system level event" to a requestor.
  - Within 45 days GO's must analyze "unexpected changes" that meet a threshold.
  - Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.
  - The MRO NSRF requests the SDT justify the timeframes chosen.
- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.

- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with "A technical justification that addresses why corrective actions will not be applied nor implemented." This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Language in R2 should be added similar to that of EOP-012-1, R7.1, to allow an explanation of why aspects of the process are not being implemented due to any technical, commercial, or operational constraints as defined by the Generator Owner.

However, we recommend revising PRC-004 to add the elements of this standard, rather than creating a new standard with a similar intent and different timelines. PRC-004 allows 120 days for analysis of Events; it's unclear why PRC-030 would not follow the same timeline. We recommend alignment of PRC-004 and PRC-030 timelines, as there could be overlap or revision of PRC-004 to include unexpected changes of 20% or more of IBRs in scope.

Also, most, if not all, NERC standards are applicable to the Bulk Electric System (BES). Why is this one applicable to the Bulk Power System (BPS) in Section A.4.2.1? Note that the Project Title is "Analysis and Mitigation of **BES** Inverter-Based Resource Performance Issues."

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	

Comment

The applicable facilities language in Section 4 is vague and difficult for entities to understand what is in scope of the Standard. Specifically, the term "BPS IBR" is broad and would encompass all transmission connected IBRs, regardless of size or interconnection voltage. Additionally, the language and formatting of the applicability sections in PRC-028, PRC-029 and PRC-030 are not consistent. These three Standards apply to the same facilities, and therefore, should use the same language. Tacoma Power recommends that Section 4 of PRC-029 and PRC-030 should be revised to align with the language proposed in Section 4 of PRC-028, as follows:

4.1. Functional Entities:

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

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (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 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy request the DT clarify a term for misoperation of an IBR so that the intent of PRC-030 is clear on intent of industry's responsibility and response.

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1

Answer	
Document Name	

Comment

Comments:

1. Overall, ATC agrees that the standard is needed and is addressing an industry need.
2. Clarify if BPS IBRs is inclusive of BES IBRs

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	

R1: The language isn't clear enough. Our Wind SME interpreted it this way:

I am concerned on the 20% apparent power without any other context on facility size or technology. Example: 67 MVA with 21 2-3 MW turbines. 2-3 turbines dropping would create a self-report and investigation. In Wind, this criteria, may drive a high and maybe unnecessary level of self-reporting (or failure to self-report) and investigations.

R3 – the comment Generator Owner shall provide data – define what this request is. If they can ask for unlimited amounts of data this could become labor intensive.

R4: 4.2 – clarify the language. Is this asking for Extent of Condition or is this saying were any other sites impacted? Needs more information

R4: 4.1 - There is concern that 45 days may not be enough to complete a full root causes analysis. Request 90 days.

R5: 5.1 - Corrective Action Plan – Is cost prohibitive considered a technical justification? Need to better define constraints much like they are defined in the new EOP-012-1 language. Example: "Could not have been implemented at a reasonable cost consistent with good business practices, reliability, or safety. A cost may be deemed "unreasonable" when implementation of protection measure(s) are uneconomical to the extent that they would require prohibitively expensive modifications or significant expenditures on equipment with minimal remaining life"

Likes 0	
Dislikes 0	
Response	

Srinivas Kappagantula - Arevon Energy - 5	
Answer	
Document Name	
Comment	

Arevon Energy provides the following comments for additional consideration.

Section 4: Applicability 4.2 Facilities:

The approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the SDT should revisit the SAR accordingly to ensure that the SDT isnt overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)" Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined in the NERC Glossary of Terms. How can an undefined term be included in a standard? This causes ambiguity over which resources the standard would apply to.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

Requirement R2:

Arevon Energy recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall identify unexpected changes in power output.".

Requirement R3:

1. Several entities, such as, Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) can request the same data from the Generator Owner (GO). There is potential for duplicity/overlap by allowing multiple entities to request the same data. The BA, RC, and TOP should coordinate any data requests and have a single entity serve as the point of contact with the GO.

2. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

3. Requirement R3 is not needed if analysis of a reportable event is being performed under R4 as R4.3 covers the notofication to the entities in R3.

Requirement R4:

1. The analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 is not required.

2. The timeframes for analysis appear to be much shorter than some other Reliabilty Standards, such as PRC-004 allow. A better approach would be to allow the timeframes for analysis as well as developing a CAP under R5 to align with PRC-004. That woudl be 120 days to conduct analysis and anotehr 60 days to deelop a CAP as needed. This would also ensure reporting consistency across the PRC standards.

3. Requirement 4.2 is an overreach and is at best speculative. This could also be a moot point if entities register each project as its own NCR#, for example.

Requirement R5 & R6:

1. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.Extending the CAP to other applicable facilities owned by the GO as mentioned previously is an overreach and speculative at best.

2. There appears to be no value in sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

3. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	

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

Answer	
Document Name	

Comment
Tri-State Generation and Transmission supports MRO NSRFs comment.

Likes 0	
Dislikes 0	

Response
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment
Please see EEI comments on proposed alternative language and applicability issues

Likes 0	
Dislikes 0	

Response
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

NERC should remain consistent with their revised Rules of Procedure by avoiding the use of “BPS IBR” terminology in the applicable facilities. This is overly broad and can lead to misinterpretation for Generator Owners who own IBRs that do and do not fit the 60 kV and 20 MVA thresholds. The third question in the Project 2020-06 comment form, copied below, is a clearer definition of IBR which NERC has determined has a material impact to the BPS. NERC should consider adopting this terminology in PRC-030

Section 4. Applicability:

4.1 Functional Entities: Generator Owner

4.2 Facilities: (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that 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

Natalie Johnson - Enel Green Power - 5

Answer	
Document Name	2023-02_Unofficial_Comment_Form_04172024 Enel Comments - Final.docx

Comment

Enel North America Inc. (Enel) has the following comments on Draft 1 of PRC-030-1:

For Requirement R2, since Enel does not agree with Requirement R1 having a documented process, R2 should be removed.

Regarding Requirement R4.3, Enel believes that notifications to applicable Balancing Authorities, Reliability Coordinators, and Transmission Operators, place an undue burden on all parties and does not align with other performance-based standards, e.g. PRC-004-6. The same can be said for Requirement R5, Corrective Action Plan development, and Requirement R6.3, notifications if Corrective Action Plans actions or timetables change. If Reliability Coordinators deem this information necessary to monitor and assess the operation of its Reliability Coordinator Area, they may use their data specification to solicit information per IRO-010-4. The same mechanisms to retrieve data are in place for Balancing Authorities and Transmission Operators.

Additionally, in regard to development of Corrective Action Plans Enel believes that the drafted language does not allow for events where IBR generator units performed as designed. Instead, there should be specific circumstances outlined for when Corrective Action Plans are required in addition to the analysis required in Requirement R4.

Enel suggests that the SDT revisit the language in Requirement R4 to include similar language as found in PRC-004-6 R1 "…identify whether its Protection System component(s) caused a Misoperation." If the Generator Owner has identified that the unexpected change in power output is a 'misoperation' (the affected IBR did not perform as designed) then a Corrective Action Plan would be required under PRC-030 Requirement R5. In doing such, the SDT should amend PRC-030 Requirement R5.2 to "Explain in a declaration why corrective actions are beyond the entity's control or would not improve BES reliability, and that no further corrective actions will be taken" as written in PRC-004-6.

Enel supports the comments made by the MRO NSRF regarding defining IBR prior to approval and implementation of PRC-030.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	

Document Name	
Comment	

Capital Power supports NAGF's comments.

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states "The SAR should be applicable to all BES inverter-based resources.". Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. "Bulk Power System (BPS) Inverter-Based Resources (IBR)".

ii. Use of the capitalized term "Bulk Power System (BPS) Inverter-Based Resources (IBR)" should be reviewed as it is not a defined term in the NERC Glossary of Terms. In addition, it is very likely that not all Bulk Power System Inverter-Based Resources will be registered even under NERC's modified Rules of Procedure. Until the definition of Inverter-Based Resources is approved, the SDT should only use the term "inverter-based resource" if needed.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

"R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.".

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

"PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: ".

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze however, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process.

ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.

i) Other Concerns:

i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004.

ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:

i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?

ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?

iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?

Likes	0	

Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	

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

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT:

4.1. Facilities:

4.1.1. (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that 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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in Real Power output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications.

R4. Each applicable Generator Owner shall analyze its IBRs performance within 120 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time.

R5. Generator Owner shall, within 60 days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. 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 R4 Part 4.2; or

4.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1.

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06. We suggest that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs “that own equipment as identified in section 4.2.1” and where section 4.2.1 would indicate “the Elements associated with (1) BES Inverter-Based Resources; and (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

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment
None.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment
Requirement R4 will require a rapid event detection and analysis process to abnormal events by all registered IBR owners. Related to the rapid timeframes associated with R4, some additional clarification for Requirement R4.2 is needed. Within the 45 days of an identified event, a GO may be challenged to also identify the applicability of the root cause problem to all its other IBR facilities. Does this applicability work include all owned IBRs across every BA/RC/TOP footprint it operates in, just neighboring IBRs close to the where the event occurred, or is it a system risk mitigation across all similar IBR make/models installed on the entire BPS? This is very critical work to be performed to maintain Bulk Power System reliability but requiring that this analysis occur within 45 days of the system event appears to be a significant burden that may not result in the adequate system risk mitigation that is intended. Rather than putting this applicability work in Requirement R4.2 within the first 45 days, we give the recommendation to remove

Requirement R4.2 and place this applicability work into Requirement R5, creating a new R5.2 that mirrors Requirement R4.2 while also requiring a CAP to be implemented for each applicable facility identified in the new R5.2.

For Requirement R5, does the CAP allow the GO to express an open-ended timeline for corrective actions, such as working with the OEM to address an identified change? It is highly unlikely that GOs will have solved the underlying performance issue within a 45-day window (e.g., coordinating with the OEM). Therefore, it is highly likely that most CAPs will involve a defined/known timeline to work with the OEM to resolve the root cause issues. Those timelines are likely hard to predict or unknown within the 45-day timeline due to challenges that GOs may have coordinating with OEMs (particularly for older inverters). Given that Requirement R6.2 allows for the updating of the CAP as timelines change, it appears this unpredictable time for OEMs to solve some root cause issues will be updated and tracked as part of R6.2. Yet we felt this point of long and unpredictable CAP timelines an important point to highlight to ensure the realities of Requirement R5 and R6 for some root cause issues are understood and thought through.

For Requirement R5 and R6, we also believe there may need to be specific callouts in the CAP language regarding updates to the IBR models following root cause event analysis, establishing reasonable timelines and deadlines on the post-event model validation effort. This may touch on the 2025 standards updates regarding Order 901 and should be coordinated early to ensure alignment and minimize the potential re-work. While getting fixes implemented in the field to address the root cause problems is essential, equally important is getting updated models (steady-state, dynamic, EMT model, etc.) with the root cause mitigations included, where applicable, so that the TP/PC have the most accurate, up-to-date IBR models that match what is in the field. Reasonability needs to be given in terms of model validation timelines due to the need to coordinate with the OEM in many cases.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

Currently there are multiple standards projects in draft including development of IBR and IBR unit defined terms. With this amount of focus and new requirements for IBRs, entities should be given additional time to implement new processes and programs for applicable facilities. A 12 month implementation period would greatly support the success of new IBR compliance programs.

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_UCF_04-17-2024_FINAL.docx

Comment

The MRO NSRF provides the following feedback:

- §4 Applicability: Inverter-Based Resources (IBR) currently is not a defined term but is capitalized. Additionally, inverter-based resource needs to be defined prior to approval of PRC-030 to ensure consistency across NERC Reliability Standards. Furthermore, the MRO NSRF would like to know which type of Generator Owner this standard is meant to be applicable to, Category 1 GO and/or Category 2 GOP? The MRO NSRF suggests: 4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (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.
- Time frames in R3 & R4 do not align.

o Within 30 days supply data for the "identified system level event" to a requestor.

o Within 45 days GO's must analyze "unexpected changes" that meet a threshold.

o Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be normal/typical order of operations.

o The MRO NSRF requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

- R4.2. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. Each I4 generation facility is unique, it should not be assumed that event conditions can be universally applied.
- R3. & R4.3. The MRO NSRF does not agree with this requirement. This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. Further, this data & analysis can be requested under other Standards, IRO-010-4 & TOP-003-5, the RC, TOP & BA should request this data if they believe it is necessary for the purposes of reliability.
- MRO NSRF suggests removing 4.3 and 6.3 entirely as they are solely administrative in nature.
- R5. et al. The MRO NSRF does not agree with this requirement as inherently assumes that there is/was an issue with how the individual generator units performed. The MRO NSRF does not agree with "A technical justification that addresses why corrective actions will not be applied nor implemented." This is not in alignment with other performance analysis standards such as PRC-004-6 & is administrative in nature without any reliability benefit. If the analysis demonstrates the equipment operated correctly, as designed and in compliance with applicable requirements then there should be no need for a Corrective Action Plan. Furthermore, there is no need to require the Corrective Action Plan to be provided to the RC as it can be requested under another Standard, IRO-010-4, the RC should request this data if they believe it is necessary for the purposes of reliability.

Likes 1	Lincoln Electric System, 5, Millard Brittany
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the suggested additional edits proposed in the EEI comments for this question.

Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA agrees with R3, as it would allow the BA or TOP to request data regarding disturbances from IBR GOs.

Addtionally, BPA seeks clarity if the TP was considered for notification in R5 and R6, as well as the RC? BPA believes there could potentially be differences in IBR behavior in planning studies due to changes in IBRs driven by CAPs required in PRC-030.

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	
Document Name	
Comment	

PG&E supports the NAGF additional comments for consideration:

a) Requirement R4:

i. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

b) Requirement R5:

i. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity activity from R5.

ii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	
Response	
Alyssia Rhoads - Public Utility District No. 1 of Snohomish County - 1	

Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Scott Thompson - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	
PNM agrees with EEI's comments. In addition, Inverter-Based Resources (IBR) must be in the NERC glossary of terms before PNM can support the implementation plan and standard PRC-030-1	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation supports NAGF comments and further adds: • “Nameplate rating” needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend revising that to “ 20% of the plant’s real power rating at the Point of Interconnection as defined in the interconnection agreement.” • SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3. • Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 5	
Answer	
Document Name	
Comment	

R3/R5:

· The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3.

· Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner. We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days).

Implementation Plan:

We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.

Likes 0	
Dislikes 0	
Response	
Stephen Whaite - Stephen Whaite On Behalf of: Tyler Schwendiman, ReliabilityFirst , 10; - Stephen Whaite, Group Name ReliabilityFirst Ballot Body Member and Proxies	
Answer	
Document Name	
Comment	

In the technical justification document, some discussion of how the 2s time relates to recent high-profile events is warranted. From reading those reports it was not clear how those events related to the choice of 2s.

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	

Patricia Ireland - DTE Energy - 4, Group Name DTE Energy

Answer	
Document Name	
Comment	

R3/R5:

The 45-day time frame in PRC-030-1 R3, to investigate and determine the cause of an unexpected change is reasonable for straightforward events but is not adequate in a situation when an in-depth analysis is required (particularly if the analysis must be performed by a contracted firm). This timeframe should be modified to align with the 120-day investigation timeline in PRC-004-6 R3.

Similarly, development of a corrective action may be straight forward or complex, requiring contracted services difficult to procure in a timely manner.   We suggest that the PRC-030-1 R5 timeline requirement of 45-days be amended to align with the PRC-004-6 R5 (60-days).

Implementation Plan:

We currently do not have alarming capabilities to identify unexpected changes for IBRs in real-time. We request that the implementation plan include an enforcement date that provides adequate time to implement this newly required detective control and its associated training and documentation.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1

Answer	
Document Name	
Comment	

- R4/R5: During a system-level event the IBR output could change by more than 20% of its MVA rating as a result of voltage change, instantaneous voltage positive phase angle change, or frequency change at the high side of the IBR main transformer. SDT may need to clarify that the analysis should investigate if the change of the IBR output meets the PRC-029 ride-through requirements. The Corrective Action Plan (CAP) could be required if the IBR response does not meet ride-through requirements.
- MH suggests that adding 4.4 “to the IBR change meets the ride-through requirements.
- MH suggests that this project should be aligned with Project 2020-02 (PRC-029).

- We recommend modifying Section 4 of PRC-030-1 as follows:

4. Applicability:

4.1 Functional Entities: 4.1.1 Generator Owner that owns equipment identified in section 4.2, 4.1.2 Transmission Owner that owns equipment as identified in section 4.2 Generator Owner that owns equipment identified in section 4.2.

4.2 Facilities: to include 4.2.3 Shunt static or dynamic reactive device(s) associated with IBR that either have or contribute to meeting the performance requirements.

- The standard is event-based compliance that requires installing recorded equipment data with higher sampling rates at all applicable legacy IBR Facilities. Therefore, we suggest that the implementation plan for PRC-030 should be aligned with Project 2021-04 (PRC-028-1) for the legacy IBRs.

- MH suggests that the drafting team ensure consistent language is used in the section 4.2 “Facilities” section with the other projects such as Project 2021-04 (PRC-028) and 2020-02 (PRC-029). MH suggested the following language be included in the applicability section. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (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.

- Time frames in R3 & R4 do not align.

1. Within 30 days supply data for the “identified system level event” to a requestor.
2. Within 45 days GO’s must analyze “unexpected changes” that meet a threshold.
3. Generator Owner analysis timeframe shall end first then the timeframe for supplying data should begin. This would be a normal/typical order of operations.
4. The MH requests the SDT justify the timeframes chosen. Perhaps aligning with the timeframes of PRC-004-6 is a better option?

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	
Document Name	

Comment

AEPC signed on to ACES comments:

- Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR:

"The SAR should be applicable to all BES inverter-based resources."

While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC's established processes by modifying the SAR in the event of a scope change.

- Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. It is our recommendation that this standard be modified so as to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6.

Thus, ACES recommends the following changes to Section 4:

- 4.1 Functional Entities:
    - 4.1.1 Generator Owner (GO)
- 4.2 Facilities:
    - 4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO, with the following exclusions:

4.2.1.1 Protection Systems
4.2.1.2 Special Protection Systems (SPS)
4.2.1.3 Remedial Action Schemes (RAS)
4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements
4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements.

- Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6.
- Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1.
- Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language:

"Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue.

Thank you for the opportunity to comment.

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

Applicability for PRC-030 should align with PRC-028 and PRC-029

Likes 0	
Dislikes 0	

Response

Ruchi Shah - AES - AES Corporation - 5

Answer	
Document Name	

Comment

1 In R1 “plant gross nameplate” is unclear and needs to be better defined, if we have multiple registered generators interconnecting to the same POI are they to be considered separately?

2 There appears to be duplication between PRC-030 R3 and PRC-028 R7, both require GOs to provide data requested by BA/RC/TOP within 30 calendar days. This could introduce double jeopardy and is not necessary, we suggest that PRC-030 R3 is removed. TOP-003 provides further ability for BA/RC/TOPs to request this data.

3 Determining applicability to other IBR facilities under R4.2 is not feasible within 45 calendar days for all cases at larger GOs. We suggest this sub-requirement be granted a more flexible or longer duration timeline with 90 days at minimum. Note that similar requirements in PRC-004 are set to 60 days at the shortest.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	
Document Name	

Comment	
As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way. We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06. We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs "that own equipment as identified in section 4.2.1" and where section 4.2.1 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (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	

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), North American Generator Forum (NAGF), and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3	
Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	
Comment	
In the applicability section, the precise scope of IBRs needs to be clearly defined rather than stating "GOs with BPS IBRs". For R3, the request to the GO for data (which must be delivered within 30 calendar days of the request) needs to be required to be made (by the requesting party) within a reasonable time frame after the event occurrence. The GO should not be required to retain all recorded event data ad infinitum.	

It seems plausible that a "system level event" (R3) may or may not involve every IBR facility. In the cases where no power output change occurred, the subparts of the analysis listed in the subparts of R4 are not applicable. This should be formally recognized in the requirement.

R3 altogether and the part of R4 referencing R3 (…or receipt of a request pursuant to Requirement R3.) are not needed and should be removed. An event which causes an unexpected change in the power output is called upon to be examined (R4) and delivered to the interested parties (R4.3) elsewhere in this draft standard. If a system event occurs where a specific IBR does not have a unexpected change in power output, there is no analysis to be done, no need to deliver results to other interested parties, and no need to assume those administrative duties to simply indicate that no unexpected change in power output occurred. What is the reliability benefit for administrative actions enumerated in R4?

The analysis specified in R4 can be duplicative of analysis required within the current draft of PRC-029. There should not be duplicative requirements (double jeopardy) in multiple standards.

Is R4.3 meant to have the GO provide the results to the requesting party? As written, the GO has a choice as to which of the three parties listed may be sent the results.

The timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

R5, as written, does not make it clear why a CAP is to be developed. What is the purpose of the CAP?

R5, as written, implies that a GO may have multiple RCs to report to - need to reword to "… to its RC" rather than "… to each applicable RC".

Events involving existing IBR facilities, in-service before the effective date of PRC-030 and the implementation plan date of PRC-028 (1/1/2030) may not have DME with recording capability for performing a detailed analysis. The implementation plan for existing units should be delayed until PRC-028 requires DME at those locations (1/1/2030).

Events involving the Protection System equipment that result in a required investigation to determine if the Protection System correctly operated due to PRC-004 should be exempt from requiring a duplicate analysis with reporting for PRC-030.

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

SMUD has the following additional comments for the Standards Drafting Team (SDT) to consider. First, the Applicability section in the proposed PRC-030-1 states: “4.2 Facilities: 4.2.1. Bulk Power System (BPS) Inverter-Based Resources (IBR).”

This language is too broad and would include *all* IBRs interconnected to the Bulk Power System at *any* voltage level. To appropriately reduce the scope of PRC-030-1, the SDT should consider the language proposed in NERC Standards Project 2021-04 Modifications to PRC-002 - Phase II, PRC-028-1 draft #2, which states:

"4.1. Functional Entities:

4.1.1. Generator Owner *that owns equipment as identified in section 4.2* [emphasis added]

4.2. Facilities: The Elements associated with (1) BES Inverter-Based Resources; and (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."

Lastly, in Requirement R3, the term "system level event" is not defined. SDT should consider defining this term, or consider other similar changes, so that an IBR owner can be requested to analyze its IBR performance for power system oscillations that do not meet the "20% of the plant's gross nameplate rating, or 20 MVA" criteria in Requirement R1, upon a request from its BA, RC or TOP. This would ensure that IBR Generator Owners are accountable to helping resolve power oscillations in which the IBR's performance may be a contributing factor.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation supports the NAGF comments and further adds:

- "Nameplate rating" needs to be clarified as they are many ways to define that especially for solar and storage plant. Recommend revising that to " 20% of the plant's real power rating at the Point of Interconnection as defined in the interconnection agreement."
- SDT needs to re-assess the need for R3 as there is overlap with R4. If an entity complies R4, there would be no need for R3.
- Analysis completion of IBR performance associated with R4 timeframe needs to be adjusted to 120 days to match PRC-004 . 45 days is not reasonable.

Alison Mackellar on behalf of Constellation Segments 5 and 6

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 provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states “The SAR should be applicable to all BES inverter-based resources.”. Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. “Bulk Power System (BPS) Inverter-Based Resources (IBR)”.

ii. Use of the capitalized term “Bulk Power System (BPS) Inverter-Based Resources (IBR)” should be reviewed as it is not a defined term in the NERC Glossary of Terms. In addition, it is very likely that not all Bulk Power System Inverter-Based Resources will be registered even under NERC’s modified Rules of Procedure. Until the definition of Inverter-Based Resources is approved, the SDT should only use the term “inverter-based resource” if needed.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. For the reasons stated in response to question 1, the NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

“R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.”.

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003/IRO-010 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

iv. PRC-030 R3 appears to introduce a potential double jeopardy risk with PRC-028 R7. Both requirements require the GO to provide data to other registered entities. We recommend that PRC-030 R3 should be removed and R4 revised to refer to PRC-028 R7:

“PRC-030-1 R4: Each applicable Generator Owner shall analyze its IBRs performance within 45 calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to PRC-028-1 R7. The analysis shall include all of the following: “.

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted. If a system level event occurs, that does necessarily mean any specific generator moved during that time period. If a generator does not move during the period in question, there is nothing to analyze however, as written, the GO must do an analysis. If the generator sees a change in output under R2, the analysis must be done. The inclusion of R3 data requests triggering an analysis is either duplicative or requiring an analysis when nothing occurred.

ii. The NAGF notes that timeframes provided in PRC-004 should be used for the proposed PRC-030 Requirement R4. The proposed 45-day time period is very short when evaluating what might be required to address an unexpected change in generation.

iii. The NAGF notes that Requirement 4.2 will be addressed under Requirement R5 and it is an overreach/speculative. Therefore, Requirement R4.2 should be removed accordingly. If the DT believes this requirement to address additional resources should stay in the standard, then the due date for the analysis should be extended a minimum of 60 days per facility to be addressed.

iv. Requirement R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens from such reporting activities.

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5. In addition, if the RC wants this data, they can request it in their data specification under IRO-010.

iii. Recommend the timeframe for the proposed CAP be modified to 60 days for consistency with other NERC Reliability Standards such as PRC-004.

f) Requirement R6:

i. Remove any reference to the RC in R6. To the extent that the RC wants this data, they can request it within their data specification under IRO-010.

g) Implementation Plan

i. The implementation plan states that PRC-028 is needed to allow the proposed PRC-030 to become effective. The NAGF does not see any relationship between the requirement to have data collected at 120 readings per second and the need to evaluate output changes that occur over a two second period. The connection between these two standards needs to be explained.

h) Technical Rationale:

i. The DT mentions that the standard uses MVA instead of MW. However, the SDT does not provide any support for why the MVA value is a better measure than simply MWs. Without some support for the use of MVA and how it might provide a higher level of reliability, the NAGF cannot support the use of a more complicated measurement process.

ii. The rationale for R3 does not make sense based on Requirement R2. It appears that the DT believes that only during a system event would the IBR see this unexpected change. If that is the case, then the BA or the TOP should be expected to initiate the evaluation process, not the GO. The GO does not have wide area view/visibility into the overall electric system. If the intent is to have the GO evaluate unexpected changes in output, regardless of a system event, then R3 is not needed. In addition, TOP-003/IRO-010 allows the BA, RC or TOP to request data for their analysis. R3 is not needed to ensure that the GO provides requested data.

i) Other Concerns:

i. The NAGF notes that when PRC-030 becomes effective, we are assuming that IBR GOs will also still need to comply with PRC-004. It's not clear how PRC-030 distinguishes itself from PRC-004 in terms of applicability. We think the Applicability section 4.2 needs to be modified to cover the collector system portion of the Facility. This would depend on the new definition of IBR Unit that is being worked on under Project 2020-06. The Balance of Plant portion should still be covered under PRC-004.

ii. It is unclear how this standard relates to PRC-028 and PRC-029. Some of the high-level questions we have related to these standard and how they interact with each other include:

i. Would an "event" identified under PRC-030 be a violation of the proposed PRC-029?

ii. How is the data recorded under PRC-028 expected to impact PRC-029 and PRC-030?

iii. Would a change in output due to system conditions exceeding the "Continuous Operating Region" or the "Mandatory Operating Region" defined in PRC-029 still require an analysis and CAP under PRC-030? If so, does that mean an IBR is not allowed to cease injection for any reason under PRC-030?

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE recommends including a time period for identifying unexpected changes in power output occurring within a two-second period in accordance with Requirement R1. The GO should have a specific process for identifying the unexpected changes in power output event within specific period to capture these occurrences. Without specific time period, many of the unexpected changes in power output may go unidentified. This could also make it difficult to audit the standard requirement if the entity did not identify any unexpected changes in power output that may have occurred. Texas RE recommends the following revision:

R2. Each applicable Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in power output **within 30 calendar days of the unexpected change in power output occurred.**

Since Requirements R3 and R4 include a timeline for the GO providing data when requested and the GO analyzing its IBRs' performance, Texas RE recommends including that in the VSLs for Requirements R3 and R4.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

This standard is problematic in that it is one of several that are all being enacted piece meal to satisfy the FERC Order. It would be better to have them all together. As currently written, how can a BA request the data if the IBR output is via a Purchased Power Agreement (PPA) only. The IBR is not yet a Generator Owner.

R3 enables the BA, RC, or TOP to request the data that the GO is purportedly being able to provide, but there is no "oversite" of the GO's process.

R3 contradicts R4. R4 gives the GO 45 days to analyze the IBR performance, but R3 requires the results to be provided within 30 days of the request. If the data requested from the GO in R3 (within 30 days of request) is different from the analysis requested in R4 (within 45 days of request), then the types of data required by R3 should be specified (or at least an example provided).

R5/R6. There is no specificity in how long the initial CAP can be set. If the plan is to fix them over the next 20 years, no updates would ever be required. There is no mechanism for the BA, RC, or TOP to hold the GO to hurry things along or follow "good engineering principles".

Compliance section 1.2 R4 bullet: a reference is made to a "declaration". Where does it state that any declaration needs to be made. What declaration is being referred to here?

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 5, Weaver Karen
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Duke Energy suggests the implementation of the following Duke Energy, EEI and NAGF review comments. Duke Energy EEI and NAGF comment modifications are bracketed by asterisks.

EEI COMMENTS

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See boldface changes below):

4.1. Facilities:

4.1.1. (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that 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 kV.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

R2. Each Generator Owner shall implement its process established in Requirement R1 to identify unexpected changes in **Real Power** output. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

R3. DELETE

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (see changes in boldface below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

4.3. DELETE

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time.

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. 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 R4 Part 4.2; or

4.2. A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1.

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

6.3. **DELETE**

NAGF COMMENTS

The NAGF provides the following additional comments for consideration:

a) 4.2 Facilities:

i. The NAGF notes that the approved SAR – Project Scope section states “The SAR should be applicable to all BES inverter-based resources.”. Therefore, the NAGF requests that the Drafting Team revisit the SAR accordingly to ensure that the Drafting Team is not overstepping their intended scope by including the language in Section 4.2.1. “Bulk Power System (BPS) Inverter-Based Resources (IBR)”.

ii. Use of the capitalized term “Bulk Power System (BPS) Inverter-Based Resources (IBR)” should be reviewed as it is not a defined in the NERC Glossary of Terms.

iii. The precise scope of IBRs to be addressed under this standard need to be more clearly defined.

b) Requirement R2:

i. The NAGF recommends deleting the proposed Requirement R1 and revising Requirement R2 as follows:

“R2 - Each applicable Generator Operator shall implement its process to identify unexpected changes in power output.”.

c) Requirement R3:

i. The NAGF is concerned with the potential for duplicity/overlap by allowing the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operator (TOP) to request data from the Generator Owner (GO). Request that the BA, RC, and TOP coordinate any data requests and have a single entity serve as the point of contact with the GO.

ii. The NAGF believes that the existing TOP-003 provides the BA, RC, and TOP the ability to request data from the GOs and therefore Requirement 3 is not necessary and should be deleted.

iii. Requirement R3 is not needed if analysis of a reportable event is being performed under R4.

d) Requirement R4:

i. The NAGF notes that analysis of an event cannot occur unless there was a change in IBR output. Therefore, the reference to Requirement R3 needs to be deleted.

ii. The NAGF notes that timeframes provided per PRC-004 should be considered for the proposed PRC-030 Requirement R4 to ensure reporting consistency across the PRC standards.

iii. The NAGF notes that Requirement 4.2 is an overreach/speculative and should be removed accordingly. *****R4.2 is already included in R5 and should be removed. During the CAP, the GOP will determine if the problem applies to other sites.*****

iv. *****R4.3 should require submittal to TOP, not RC and BA. GOs with many sites will have increased administrative burdens for reporting activities.*****

e) Requirement R5:

i. The purpose of the Corrective Action Plan (CAP) needs to be better defined to state what it is intended to accomplish.

ii. The NAGF does not understand the value of sharing the CAP with the RC and how the RC would use such information. Recommend to delete this administrative activity from R5.

iii. Recommend consistency for the proposed CAP timeframe with other NERC Reliability Standards such as PRC-004.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

R2. - This is an unnecessary requirement as it is not in alignment with other performance analysis standards. It should be removed.

R3. - This requirement seems to be redundant to PRC-028, requirement R7. It should be removed.

R4. - The requirement needs to define that only misoperations/faults need to be analyzed.

R5. - The requirement needs to be revised to state that CAP is not needed if IBR reacted as designed.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

WECC suggests that the

SDT should consider the definition of Inverter-Based Resource being developed. As is, the “Facilities” section is not consistent with other Standards being developed. Additionally, Inverter-Based Resource should be used instead of “plant” in R1. Consider the use of IBR or Inverter-Based Resource for consistency throughout Standard (e.g., R3/R4 uses IBR, R4 additionally uses IBR facilities, R5 uses Inverter-Based Resource and R1 uses plant).

The Technical Rationale description “system level event” is accurate but may limit a BA/RC/TOP approach to IBRs response review. Project 2023-01 limits loss to MWs (current ≥ 500 MW) which is different from the expected response review criteria as explained in the Technical Rational. Voltage collapse scenarios can be localized and IBR responses would need to be reviewed to understand the reasons (and mitigate future risk of re-occurrence).

WECC believes GOs should analyze performance of Inverter-Based Resources if the criteria is met in R1 without needing a system level event to be identified.

Providing the analysis of the response to the RC, BA, and TOP but only providing the CAP to the RC leaves a gap in reliability for the BA. How does planning (TP or PC) receive the response analysis information or the CAP actions that may impact planning models?

Technical Rationale mentions "acceptable" technical justification expectations that could essentially negate mitigation of risk. Since this Standard is around "unexpected" occurrences, interconnection requirements may need to be updated to mitigate risks (see multiple event reports regarding Inverter-Based Resource losses). Allowing a GO to provide that technical justification may cause entities to take no action which does not support reliable operations. Suggest dropping "material modification" as the term was removed from FAC -002 Standard and replaced with "qualified change". FAC-002 should be considered by the GOs and a "qualified change" that impacts reliability should not go unresolved. As is, there is no language regarding approval of the CAP or any specific maximum time limit for a CAP which implies an operational risk could go unresolved for an indefinite period. WECC appreciates the "operating restrictions" comments in the Technical Rationale but system conditions (or the political environment) may not allow a BA/RC/TOP to implement those restrictions (assuming including disconnecting the Inverter-Based Resource).

The applicability sectioin indicates that this standard is limited to BPS Inverter-Based Resources. WECC interpprets this to be excluding non-BPS Inverter Based Resources? As non-BES Inverter-Based Resources proliferate, performance may need reviewed and should be considered.

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

As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way.

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.

We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs "that own equipment as identified in section 4.2.1" and where section 4.2.1 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (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

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

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the suggested additional edits proposed in the EEI comments for this question.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The language in Requirement R3 should be restructured to clarify that the BA, RC, or TOP may require the GO to initiate and perform analysis related to System-level events, which is the intent of this requirement. Additionally, the requirement to provide “data” when requested should be expanded to also require the provision of “information” when requested. As reflected in recent changes made to IRO-010 and TOP-003, the term “information” encompasses more than just data (e.g. PMU/DFR/DDR/SCADA data) and may include settings, OEM documentation, unit parameters, etc.

The SDT should ensure that the timelines in Requirement R4 are consistent with the timelines used for the Event Analysis program. If 45 calendar days are needed for an R4 analysis, then the SDT should coordinate with the Event Analysis Subcommittee (EAS) to coordinate the Event Analysis program timelines as needed.

Under Requirement R5.1, the CAP should, if possible, use the IBR and IBR Unit definitions that are being developed in Project 2020-06, both to ensure consistency and to clarify that the CAP may at times not be for the entire plant but for individual turbines or inverters. Based on the responses provided during the Project 2020-02 webinar, ERCOT is concerned that this SDT may be assuming the Project 2020-02 SDT is addressing the issue of partial reductions in output (IBR unit trips/abnormal reduction) not being allowed, while the Project 2020-02 SDT may be assuming this SDT is addressing that topic. Regardless of which SDT ultimately addresses the topic, the two SDTs should work together to ensure consistency among their respective standards and to ensure that the standards clearly provide that partial reductions in output (IBR unit trips/abnormal reductions) would constitute a performance failure even if the entire plant does not trip.

Requirement R5.2 inappropriately allows GOs to avoid implementing corrective actions without receiving an assessment of the resulting reliability impact or any sort of oversight or pre-approval. If, consistent with FERC Order 901, planners and coordinators must take System-level actions to address the reliability impacts of exemptions or performance failures (the mitigation of which may take months or even years to implement without a firm requirement on timeliness), leaving corrective actions unimplemented at the IBR or IBR Unit level may create a reliability gap until System-level mitigations are implemented (if System changes can even practically resolve the reliability impact, which is not certain). Unmitigated ride-through performance failures can, in aggregate, have an impact that triggers UVLS, UFLS, Cascading outages, instability, and uncontrolled separation.

Requirement R6 should include language that requires the CAP to be implemented as soon as practicable and no later than a specific deadline (e.g., 90 days) unless otherwise approved by the RC. Otherwise, CAPs could take years to implement or never be implemented at all. While ERCOT agrees that, as described in the Technical Rationale, one way of mitigating this risk is to impose operating restrictions that incentivize timely CAP implementation, it would be better to address this issue in the Requirement instead of in the Technical Rationale. This is especially important since NERC has prioritized planner and operator requirement changes ordered in FERC Order 901 after the initial wave of projects, and these two issues are explicitly linked (operating restrictions may be needed to address reliability risks that arise from exemptions or unmitigated performance failures). Assuming that future projects will address this issue does not adequately or timely address this reliability risk; consequently, this issue should be addressed in this standard, especially given that some Generator Owners continue to dispute RC authority to impose operating restrictions.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI offers the following additional edits to PRC-030-1:

Applicability Section Comments: EEI does not agree that the Applicability Section (4.1. Facilities) is clear. We suggest alignment with the recommendations provided by the Project 2020-06 SDT (See proposed changes below):

4.1. Facilities:

4.1.1. (1) BES Inverter-Based Resources; and (2) Non-BES Inverter Based Resources (IBRs) that 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.

Requirements R2 through R6 Comments: EEI suggests the following changes to better align with other NERC Reliability Standards:

Propose combining Requirement R2 with R1: See EEI's justification within our response to question 1.

Propose deleting Requirement R3: EEI disagrees that there is a need for Requirement R3 because there are existing requirements contained within TOP-003 (for TOPs & BAs) and IRO-010 (RCs) that allow these registered entities to obtain this data by simply including the data within their data specifications.

Requirement R4 Proposed Changes: Under PRC-004, responsible entities have 120 days to conduct their analysis of equipment misoperations. At a minimum, the same amount of time is required for IBR GOs to assess aberrant performance of IBRs, noting the analysis of IBR performance is more complex requiring the involvement of vendors and OEMs to fully assess the reasons and possible solutions. Additionally, Requirement R4, subpart 4.3 is unnecessary noting that responsible BAs, RCs, and TOPs can obtain the results of entity analysis through TOP-003 and IRO-010 data specifications. (See proposed changes below)

R4. Each applicable Generator Owner shall analyze its IBRs performance within **120** calendar days of either the event identified pursuant to Requirement R2 or receipt of a request pursuant to Requirement R3. The analysis shall include all of the following: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1. The cause(s) of unexpected change(s) in power output;

4.2. The applicability to its other IBR facilities that could be affected by the same cause of unexpected change(s) in power output; and

Requirement R5 Proposed Changes: Under PRC-004, responsible entities are provided 60 days from the completion of their analysis to the development of a CAP. GOs should be provided the same amount of time. (see proposed changes below)

R5. Generator Owner shall, within **60** days of completing the analysis in Requirement R4, develop one of the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1 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 R4 Part 4.2; or

5.2 A technical justification that addresses why corrective actions will not be applied nor implemented.

Requirement R6 Proposed Changes: Requirement R6, subpart 6.3 should be deleted. There are no similar requirements within PRC-004 and RC reporting requirements are not needed within PRC-030-1. (see proposed changes below)

R6. Each Generator Owner shall, for each of its CAPs developed pursuant to Requirement R5: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Long-term Planning]*

6.1. Implement the CAP;

6.2. Update the CAP if actions or timetables change; and

Likes 0	
Dislikes 0	

Response

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3

Answer	
Document Name	

Comment

The period to analyze IBR performance within 45 calendar days should be increased to 120 days to match PRC-004 and allow time to determine the root cause especially if OEM support is required.

NIPSCO also recommends that the SDTs for PRC-028, PRC-029, and PRC-030 review their proposed standards to ensure there is a consistent plan to achieve the goal of correcting IBR performance issues.

The period to develop CAP should be within 60 calendar days instead of 45 days to align with PRC-004.

The notification in R4.3 is confusing as written, “to each applicable Balancing Authority, Reliability Coordinator, or Transmission Operator”, is the notification suppose to be to all listed, in which case the “or” should be “and”.

The implementation period of six months would be adequate for the purpose of identification, but if equipment changes or upgrades are needed to comply the period should be increased to 2 years to allow for these changes or upgrades.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments:

"As Requirement R5 is the twin requirement of PRC-004 Requirement R5, we suggest using bullets instead of sub-requirements so that the text to both requirements is harmonized and is read the same way.

We are concerned that the standard refers to a defined term for IBR which has yet to be adopted in project 2020-06.
We suggest that the drafting team ensure consistent language is used in the section 4.2 "Facilities" section with the other projects such as 2020-04 (PRC-028) and 2020-02(PRC-029). Section 4.2.1 refers to BPS IBRs, however it is our understanding that section 4. 1.1 would refer to GOs "that own equipment as identified in section 4.2.1" and where section 4.2.1 would indicate "the Elements associated with (1) BES Inverter-Based Resources; and (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	
Colin Chilcoat - Invenergy LLC - 6	
Answer	
Document Name	
Comment	

Invenergy thanks the drafting team for their work and the opportunity to provide comments.

The Applicability section would benefit from alignment with the other IBR-focused standards in development. As currently drafted, PRC-028-1, PRC-029-1, and PRC-030-1 all use different language to describe the same applicable Facilities.

Regarding the timeline in requirement R4, 45 days is not enough time for sufficient analysis. In almost all cases, evaluation and analysis will need to be supported by IBR OEMs, and it is not guaranteed that resources exist to provide feedback that quickly.

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	

Document Name	
Comment	

On behalf of the SERC Generator Working Group:

Applicability section: Is the intent to capture the new Category 2? Suggest defining more precisely. Also, has BPS been used before it defining facilities?

For R4.3, we suggest eliminating R3 altogether along with the reference to R3 in R4 because the residual part of the requirement will achieve delivering the analysis of any unexpected output change to the parties of R3.   If no change was detected at the plant, no analysis was required, and no reporting should be necessary.   (and the request that may come from R3 would yield nothing more than an acknowledgment of no change detected, which is of no value).

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	

TEPC agrees with EEI comments to revise Section 4.1 Facilities, combining requirement 1-2, deleting requirement 3 to remove duplication of efforts, and revising requirements 4-5 the number of days for analysis.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2

Answer	
Document Name	
Comment	

• The timelines in R3 and R4 don’t seem to make sense and appear to contradict. If there’s a system level event, does this specify that there are 30 or 45 days to respond?

• In any case, either 30 or 45 days is a very long period of time to analyze unexpected changes in generator power output . We believe that it could and should be done within 5 to 7 business days. It’s likely part of a larger investigation that would take weeks to do AFTER receiving the IBR information. Within 30 days there should be a final report (not 45 days) per R4. Given the information that these installations have access to, providing the information in 5 to 7 business days should be reasonable.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

Avista agrees with EEI's comments

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	
Document Name	

Comment

We fully support PRC-030 and the need to establish performance requirements for IBRs. The first ballot of the standard is a strong step in the right direction to ensure BPS reliability. We agree with EEI's comments and support the changes suggested in those comments.

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
• Section 4 of PRC-030-1 draft 1 includes all Bulk-Power System IBRs; however, this is not in line with the Project Scope as defined in the SAR: "The SAR should apply to all BES inverter-based resources." While we understand the time constraints placed upon the SDT by FERC Order 901, we would prefer to follow NERC's established processes by modifying the SAR in the event of a scope change. • Furthermore, we are concerned that as written, this Reliability Standard overlaps with the requirements of PRC-004-6. We recommend that this standard be modified to specifically exclude any components already included under PRC-004-6 . In short, it is our opinion that PRC-030-1 should only apply to those event types not covered by PRC-004-6. Thus, ACES recommends the following changes to Section 4: 4.1 Functional Entities: 4.1.1 Generator Owner (GO) 4.2 Facilities: 4.2.1 Inverter-Based Resource (IBR) meeting the registration criteria for either a Category 1 or Category 2 GO , with the following exclusions: 4.2.1.1 Protection Systems 4.2.1.2 Special Protection Systems (SPS) 4.2.1.3 Remedial Action Schemes (RAS) 4.2.1.4 Underfrequency Load Shedding (UFLS) that is intended to trip one or more BES Elements 4.2.1.5 Undervoltage load shedding (UVLS) that is intended to trip one or more BES Elements. • Additionally, we at ACES have concerns with the timelines specified in Requirements R3 and R4. Requiring the GO to collect data and analyze an event within 30 calendar days and 45 calendar days respectively is much more stringent than identifying and analyzing similar event types under PRC-004-6 Requirements R1, R2, and R3 (i.e., 120 calendar days). We believe these shortened timelines are overly burdensome to the GO and should be aligned with PRC-004-6. • Moreover, Requirement R3 does not apply any constraints for how long the BA, RC, or TO have to request the data from the GO. Is the GO expected to store and maintain all data for all applicable IBRs for an indefinite period of time? As the BA, RC, and TO already have the ability to request data from the GO under Reliability Standards IRO-010 and TOP-003, we recommend that Requirement R3 and Requirement Part 4.3 be struck from PRC-030-1. • Lastly, it is the opinion of ACES that Requirement R5 should be modified such that it only applies when an issue is identified after performing the analysis required by R4. We recommend the following language: "Each Generator Owner that identifies a performance issue under Requirement R4 shall, within 45 days of completing the analysis, develop a Corrective Action Plan (CAP) for correcting the identified issue. The CAP shall include other applicable facilities owned by the Generator Owner as identified in Requirement R4 Part 4.2 that utilize the same equipment that caused the performance issue." Thank you for the opportunity to comment. ODEC has the following additional comments: • In ODEC's opinion, adding additional PRC Reliability Standards that are similar to existing standards creates uncertainty and confusion as to which standards apply to which resource types. We recommend either creating a new category or subcategory of named "IBR" specific standards. Please see the following 2 different examples of potential updates to the NERC Standards Numbering System:

- New Topic Area
    - IBR-001-1
  - New sub-category
    - PRC-004-IBR-1
- ODEC believes that either PRC-004 or PRC-030 should apply to IBRs, but not both. We recommend exempting IBRs from PRC-004 and incorporating any applicable PRC-004-6 requirements into PRC-030-1.

Likes 0	
Dislikes 0	

Response