NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues | Draft 4
Comment Period Start Date:	8/28/2024
Comment Period End Date:	9/13/2024
Associated Ballot(s):	2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Implementation Plan AB 4 OT 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues PRC-030-1 AB 4 ST

There were 45 sets of responses, including comments from approximately 129 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Jamie Calderon (via email) or at (404) 446-9647.

Questions

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

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

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO

					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	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
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
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
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC

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

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

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE sees no alternative or more cost-effective options.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	No
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	No
Document Name	
Comment	
Duke Energy does not normally respond to cost-effective questions and offers no alternatives to what has been proposed in PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF and NAGF.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI offers no alternatives to what has been proposed in PRC-030-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI offers no alternatives to what has been proposed in PRC-030-1	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment and support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
Please see "EEI Comments"	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment and support.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the 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	
Thank you for the response.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Brian Lindsey - Entergy - 1	
Answer	Yes
Document Name	
Comment	
A more cost-effective way would be to let the Transmission Operator identify the events for which service data needs to be studied. Have the Generation Plants responsible for providing that data. Evaluating all potential events results in more work that may or may not provide benefit to the Bulk Power System.	
Likes 0	
Dislikes 0	

Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, "It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues."	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
The SDT has not provided any cost or expected reliability indices improvement estimates. Consequently, it is impossible for entities to determine if this proposal is cost effective to address recommendations of FERC order 901 or if, or to what extent, this proposal will improve reliability. Reliability standards should not be added or changed until the SDT provides said information so that Registered Entities can make educated determinations related to the cost and benefits of reliability standard modifications or new proposals. Basically, what we are being asked to do is to analyze the cost and reliability benefits this proposal would provide without any data.	
Likes 0	
Dislikes 0	
Response	
The Project 2023-02 SAR didn't direct the Drafting Team to develop a cost analysis for the development of this standard. The Drafting Team developed the standard to provide the reliability benefits intended by the SAR.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	

Answer	Yes
Document Name	
Comment	

The MRO NSRF does agree that inverter-based resources need to identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, changes in Real Power for the following are excluded:

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

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

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

· Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

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

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

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

1.1.3. Assess any performance issues identified and if corrective actions are needed; and 1.1.4. Determine the applicability of the root cause(s) to the Generator Owner's other Inverter-Based Resource facilities. 1.2. Upon request, provide the analysis results to the requesting associated Reliability Coordinator, Balancing Authority, or Transmission Operator.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comments. The DT exempted Protection System Misoperations from the Requirement R1 determination however correct operations of Protection Systems need to be analyzed to verify Ride-through performance requirements. The DT reviewed the suggestion to eliminate the process requirement however kept it because it is an important element to ensure a process is in place that could adequately capture events. The documented process requirement can be found in other Reliability Standards such as CIP-003, CIP-004, CIP-005, and PRC-012. The DT reviewed the suggestion and considered increasing the time however is holding to 90 days to ensure analyzing and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover a broad array of operations due to wide scale weather events such as hurricanes. The thresholds only catch a subset of events that pose a risk to the system stability. The RC, BA, TOP require the ability to direct GOs to analyze other events that pose risks to the system. The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans.	
Ruchi Shah - AES - AES Corporation - 5	

Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF comment.	
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	
Please see the DT's response to the NAGF comment.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF comment.	
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	
Please see the DT's response to the MRO NSRF comment.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC	
Answer	Yes
Document Name	
Comment	
PNM agrees with the comments of MRO: The MRO NSRF does agree that inverter-based resources need to identify, analyze, and mitigate unexpected changes of Real & Reactive Power output. However, it is not reasonable, practicable or cost effective to have Generator Owners analyze every change in Real Power	

output based on the magnitudes proposed in Requirement R1 even with the exclusions outlined in the proposed Requirement R1. The MRO NSRF strongly encourages the SDT to consider the process that will be required to demonstrate compliance with the proposed Requirement R1 and the amount of administration that will be required to verify whether a change in active power meets the criteria for analysis in the proposed Requirement R1. In addition, the MRO NSRF has offered more cost-effective alternatives for the SDT.

- PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. Further, the exclusionary bullet four assumes that a Misoperation has occurred. The MRO NSRF suggests the following update to PRC-030-1, Requirement R1, Bullet 4, which aligns with the language in PRC-004-6.

o Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004.

- PRC-030-1, Requirement R1, Draft 4. The MRO NSRF would like to reiterate that Requirement R1 “documented process to identify unexpected changes” is not a requirement within the SAR’s scope. According to the SAR, Generator Owners need to “analyze performance issues identified at their facilities”. Having a documented process is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost-effective. The MRO NSRF suggest removing this requirement language in its entirety.

- PRC-030-1, Requirement R2, Draft 4, “90 calendar day”. As previously commented, the MRO NSRF does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6. Further, the SDT commented in the draft two responses the reason for maintaining the 90 calendar day timeframe was “to ensure diligence”, the MRO NSRF does not feel that this is an acceptable justification for maintaining a 90 calendar day timeframe.

PRC-030-1, Requirement R2, Draft 4. The MRO NSRF does not agree with allowing the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA) to be able to request an analysis of any a change in “the inverter-based resource(s) Real Power output”; the criteria for this analysis shall be the same criteria as outlined in Requirement R1.

- PRC-030-1, Requirement R3, Draft 4: The MRO NSRF would like to reiterate that being required to provide either a ‘Corrective Action Plan or justification of why corrective actions will not be applied to the Reliability Coordinator (RC), Transmission Operator (TOP) and Balancing Authority (BA)’ is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6, is administrative in nature without any reliability benefit and not cost effective. The MRO NSRF suggests the following language:

o “…and upon request provide it to the applicable associated Reliability Coordinator, Balancing Authority, and Transmission Operator:”

- PRC-030-1, Requirement R4.3, Draft 4. The MRO NSRF would like to reiterate that the proposed Requirement R4.3 is not a requirement within the SAR’s scope. This proposed requirement is not in alignment with other performance analysis standards such as PRC-004-6,

is administrative in nature without any reliability benefit and not cost-effective. In addition, the MRO NSRF does not understand why the Balancing Authority, and Transmission Operator are not included in the requirement language. The MRO NSRF suggests making requirement R4.3 contingent on requests made under Requirement R3. Essentially, a responsible entity only needs to provide external updates of the corrective actions plans to the requesting entity if those corrective actions plans were requested under Requirement R3.

Based on the aforementioned comments the MRO NSRF suggests combining Requirements R1 & R2 as follows:

R1. Each applicable Generator Owner, within 120 calendar days of complete facility loss of output, or changes in Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, or following a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator that identified a Disturbance and a change in the

Inverter-Based Resource(s) Real Power output that are at least 20 MW and at least 10% of the plant's gross nameplate rating, occurring within a 4 second period, shall, changes in Real Power for the following are excluded: · Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance; · Resource dispatch, resource ramping, planned outages, or planned resource testing; · A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or · Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004. 1.1. Analyze its IBR facility performance during the event, including: 1.1.1. Determine the root cause(s) of change(s) in Real Power output; 1.1.2. Document the facility's Ride-through performance including Reactive Power response during the event; 1.1.3. Assess any performance issues identified and if corrective actions are needed; and

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

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

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to the MRO NSRF.	
Michael Goggin - Grid Strategies LLC - 5	
Answer	Yes
Document Name	
Comment	

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

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

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

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

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

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

Not only does a requirement to maintain active power production instead of prioritizing reactive power production during a voltage disturbance risk exacerbating voltage collapse, but it is also infeasible in many cases. If the voltage is low during and following a disturbance, even if an IBR plant continues to inject its full pre-disturbance level of active current, it cannot maintain the level of active power it was delivering because voltage is now lower and active power is the product of voltage and current. Moreover, to increase reactive power injection, a generator must typically shift its output away from active power injection (power is comprised of active and reactive components). Both synchronous and asynchronous generators have a finite ability to produce power, so they must reduce real power (P) production to increase reactive power (Q) along the P-Q generator capability curve.[4] In most cases, it is infeasible for any type of generator to maintain active power production while also increasing reactive power output during a disturbance.

Solutions

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

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

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

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

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

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

{C}[4] See Figure 4 for an example of a synchronous generator's P-Q curve and Figure 5 for a non-synchronous generator's P-Q curve: https://link.springer.com/article/10.1007/s40565-019-0535-4

Likes 0	
Dislikes 0	

Response

Thank you for the comments and concern. The DT performed an assessment on how frequently the thresholds could be met and included this information in the Technical Rationale. The DT agrees that some data automation will be helpful for screening events. The DT recognizes some expected, proper performance could meet the Requirement R1 thresholds and require further investigation. Capturing some level of false positives is a consequence of most simple screening methods. The DT aimed to balance accuracy, and mitigation of risks in developing the criteria to help further reliability.

Colin Chilcoat - Invenergy LLC - 6

Answer	Yes
Document Name	

Comment

As currently drafted, Invenergy believes PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.

Likes 0	

Dislikes 0	
Response	
The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, “It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues.”	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
GO/GOPs will need more information to adequately assess the cost effectiveness of the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment.	
Rhonda Jones - Invenergy LLC - 5	
Answer	Yes
Document Name	
Comment	
PRC-030-1 imposes a significant resource burden on GOs without commensurate benefit to reliability. GOs will need to dedicate significant resources to identify, analyze, and validate events that may pose no reliability concern. Invenergy understands that regional entities may	

not have the ability to identify single plant performance issues, but they would be able to identify events that have a system-level impact, at which point the GO could be instructed to provide greater analysis of its performance during that specific time period.

Likes 0	
Dislikes 0	

Response

The purpose of the SAR for Project 2023-02 is to have GOs self-identify events and investigate performance, the DT felt this is the best course forward to ensure reliability. The SAR notes, "It is important that the GO is accountable for analyzing these events, has necessary monitoring equipment installed, and cooperates with the BA/RC by providing operational data and analytical results. The past few NERC disturbance reports have highlighted limited awareness and understanding by facility owners that abnormal performance has even occurred, and therefore identification of possible performance issues should be initiated by either the IBR facility owner/operator (i.e., the GO/GOP) or by the transmission entities with a wide-area view (i.e., the TOP, RC, or BA). However, the onus of analysis and development of mitigating actions should be on the asset owner to eliminate the possible risk of repeated abnormal performance issues."

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

Answer	Yes
Document Name	

Comment

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

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

- Changes associated with intermittent primary energy source availability, created by changes such as variation in wind speed and solar irradiance;
- Resource dispatch, resource ramping, planned outages, or planned resource testing;

- A Transmission or collection system loss that, by configuration, disconnects the IBR generator; or
- Real Power reduction due solely to a Protection System Misoperations being analyzed and corrected under PRC-004 Reliability Standard.

Secondly, ACES does not agree with the removal of the word "identifying" from Requirement R2. It is the opinion of ACES that removing this word places an undue burden on the GO to perform the analysis within an unnecessarily compressed timeline. While it is still our opinion that a timeline of 120 days is more appropriate as it is more consistent with PRC-004-6; we do not see it as an insurmountable hurdle to require a 90 calendar-day timeline so long as it begins when the GO identifies the event. Thus, we recommend modifying R2 as follows:

R2. Each applicable Generator Owner shall perform the activities identified in each subpart of this Requirement, within 90 calendar days, of either:

- identifying a Real Power change event pursuant to Requirement R1 or,
- receiving a request from its applicable Reliability Coordinator, Balancing Authority, or Transmission Operator wherein the requesting entity identified an event meeting the thresholds established in Requirement R1

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

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

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

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

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

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

Furthermore, it is the opinion of ACES that the GO should not be required to submit a CAP to the RC, BA, nor TOP. This is not in line with the requirements identified in PRC-004-6 Requirement R6 nor does it add any appreciable reduction in risk while at the same time increasing the compliance burden for the GO and likely the RC, BA, and/or TOP. In other words, why should the GO submit its CAP to these entities if they are not required to perform any action(s) upon receipt (or even acknowledge receipt)? In short, if the RC, BA, or TOP desires an opportunity to review the CAP(s) developed by the GO, there is already a mechanism in place for this via the documented data specification(s).

Lastly, requirements R3 and R4 of the proposed PRC-030-1 do not align with one another. For example, as written, R3 requires a CAP be provided to the RC, BA, and TOP whereas R4 Part 4.3 only requires that the RC be notified. We recommend modifying these sections so that they are inline with one another. In other words, either require the GO to notify the RC, BA, and TOP in R4 Part 4.3 or remove the BA and TOP from Requirement R3.

Likes 0	
Dislikes 0	

Response

The DT reviewed the suggestion however kept the documented process because it is an important element to ensure a process is in place that could adequately capture events. The documented process requirement can be found in other Reliability Standards such as CIP-003, CIP-004, CIP-005, and PRC-012.

The DT reviewed the suggestion and considered increasing the time however is holding to 90 days to ensure analysis and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.

The DT removed the “identifying” qualifier in Requirement R2 prior to posting Draft 4 for additional ballot and tied the timing of R2 to the event date. This change was made because, as originally written, there was an open-ended timing problem for the GO to identify the event. Without tying the GO’s identification response to the event date, there is a risk of missing events entirely due to lack of information or persistence.

The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the 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	
Thank you for the response.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	

No comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	

2. Provide any additional comments for the Drafting Team to consider, if desired.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
ATC had not initially joined the ballot pool for this standard as it was not directly applicable to TO/TOP, however, we would like to express our support of the standard as written and thank the team for their effort.	
Likes 0	
Dislikes 0	

Response	
Thank you for the support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	
Document Name	
Comment	
NRG is in alignment with NAGF's comments	
Likes 0	
Dislikes 0	
Response	
Please see response to NAGF’s comment.	
Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	

Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would the Generator Owner still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0	
Dislikes 0	

Response

1. CIP applicability is outside the scope of this standard.
2. Please refer to the facility definition in the application section of the standard. PRC-030’s Requirement R1 language also looks at the “plant’s gross nameplate language.”

3. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.
4. Thank you for the comment.
5. Determination of elements requiring a CAP should be left to the applicable entities responsible for root cause analysis.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the support, see response to NPCC Standards Committee's comments.	
Bret Galbraith - Seminole Electric Cooperative, Inc. - 6	
Answer	
Document Name	
Comment	

1. If a device can impact a plants gross nameplate rating by 10% or 20 megawatts respectively, does that Cyber Asset now become CIP applicable? I.e., what impact to CIP will this have if the measure of detriment is 20 MW or 10% of a total unit? Can the Standard Drafting Team add color to this question?
2. Take for instance a site that has both PV and BESS. The PV has a gross nameplate of 74.5 MW. The BESS has a gross nameplate of 30 MW. However, the site is synthetically limited to 74.5 MW, i.e., the output cannot exceed 74.5 MW. Would Seminole still need to use the gross nameplate rating of the combined generators or can the 20 MW/10% value be calculated off of any synthetically limited value?
3. GO should have a time period of 120 days in R2 after identification of R1 events and 120 days to complete R3, to be consistent with PRC-004 Requirements. This will give entities a chance to determine which Standard to apply to an event.]
4. R4.3 reporting requirements should be consistent with PRC-004 R6. PRC-004-6 R6 does not require notification every time a CAP changes. The Standard Drafting team should mirror this language or add context into the technical guidance that describes why reporting should differ.
5. The Standard Drafting team should identify which elements to evaluate as requiring a CAP (i.e. elements that are directly responsible for the ride-through capabilities of an IBR).

Likes 0	
Dislikes 0	

Response

1. CIP applicability is outside the scope of this standard.
2. Please refer to the facility definition in the applicability section of the standard. PRC-030's Requirement R1 language also looks at the "plant's gross nameplate language."
3. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.
4. Thank you for the comment.
5. Determination of elements requiring a CAP should be left to the applicable entities responsible for root cause analysis.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

NPCC RSC supports the Project.

Likes 0	
Dislikes 0	

Response

Thank you for the support.

Colin Chilcoat - Invenergy LLC - 6

Answer	
Document Name	

Comment

Thank you for the opportunity to provide comments.

Likes 0	
Dislikes 0	

Response

Thank you for the comment.

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

Answer	
Document Name	

Comment

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

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

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

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

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

Likes 0	
Dislikes 0	

Response

The DT determined that the threshold as written would eliminate smaller events and appropriately balance risks while ensuring reliability.

The RC, BA or TOP can request analysis of events outside R1 criteria when the GO is self-identifying events in Requirement R1. In Requirement R2 Part 2.2 this gives the Reliability Entity the ability to request a GO perform analysis and prove the Reliability Entities the results.

Under Requirement R2, the GO has 90 days to perform the analysis of the event. The DT felt that 90 days provided an appropriate amount of time for a GO to analyze the event to promote reliability.

The DT determined that at least 20 MW or at least 10% would eliminate smaller events and appropriately balance risks while ensuring reliability.
The DT was limited to the parameters of SAR in regard to the EOP-012 comment.

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 appreciates the Standard Drafting Team's actions to change the Section 4, Applicability language to match that in the proposed PRC-028-1 and PRC-030-1 reliability standards. Although time is short to make further changes, the following improvements should be considered by this Standard Drafting Team or a future Team to enhance PRC-030-1.

1) PRC-030-1, Requirement R1, Draft 4 still contains an overlap with NERC Reliability Standard PRC-004-6, Requirement R1. The exclusionary bullet four assumes that a Misoperation has occurred and does not leave room for correct operations of protection systems. This would create an unnecessary burden on registered entities to create compliance documentation for both PRC-004 and PRC-030 for the same event caused by the correct operation of a protection system. We agree with the recommendation provided by the MRO NSRF to revise the bullet four language to the following and remove the overlap:

"Real Power reduction due solely to BES interrupting device operations being analyzed under NERC Reliability Standard PRC-004."

2) PRC-030-1, Requirement R2, Draft 4, "90 calendar day". SMUD does not agree with the 90 calendar day timeframe and believes it should be 120 days similar to PRC-004-6.

Likes 0	

Dislikes 0	
Response	

1. Thank you for the comment. The DT exempted Protection System Misoperations from the Requirement R1 determination however correct operations of Protection Systems need to be analyzed to verify Ride-through performance requirements.
2. The DT reviewed the suggestion however the DT considered increasing the time and is holding 90 days to ensure analysis and correcting unexpected performance is a focus for the GO. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes.

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

Answer	
Document Name	
Comment	

The PRC-030 standard language (Applicability Section 4.2.2) needs to align to Project 2020-06 for defining the term that will represent Category 2 IBRs

Similarly, the PRC-030 Implementation plan (footnote 8 on page 3 and the term definition for "applicable non-BES IBRs" used on Page 4) needs to align to Project 2020-06 definition of the Category 2 BES

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. There are no category 2 IBRs in 2020-06 IBR Definition. The facilities section aligns with the change in NERC Rules of Procedures (ROP) and those that leverage the definition for IBR need to specify which IBR.

Scott Thompson - PNM Resources - Public Service Company of New Mexico - 1,3,5 - WECC

Answer	
Document Name	

Comment	
Kindly suggest greater consideration of the standard drafting team to take in consideration therecommendations made by OEM and GO/GOP of existing IBRs on capabilities vs reliabiliaty improvement vs cost, from previous and current commenting.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team developed the standard in alignment with the SAR while balancing the need between ensuring continued reliability of the grid and due consideration of industry stakeholder inputs.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	
Document Name	
Comment	
SRP supports the standard but would like to see the 90 day portion of R2 reduced to 7 days. In order to ensure impacts to the BES are minimized, it seems important to define root causes to determine if an IBR can be safely returned to service or if mitigations need to be prepared if returned to service, or if the IBR needs to be kept on forced outage until mitigated. As we become more and more dependent on this type of resource for load serving and regulating needs this level of urgency is warranted in our opinion.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team developed the standard and timing requirements based on reliability needs and industry stakeholder inputs.	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	

Document Name	
Comment	

R1 requirements
The technical rationale states that criteria for triggering analysis were chosen with the intention of screening out “small active power changes” while being low enough to detects events that present a reliability risk. The DT points to 3 studies performed at solar and wind facilities in Texas where wind speed and solar irradiance changes did not result in greater than a 20mw or 10% nameplate rating Real Power output ? in a 4 second window. These studies ranged from 1 month to 1 year, and 160MW-500MW nameplate ratings. Many factors can affect both the Real Power output, as well as the Power rate of change for IBR’s, particularly solar, where temperature, latitude, elevation, humidity, asset age, and geographical features, can all impact the effective output and how fast it may change based on disturbances to its energy source. These studies may provide insufficient data to draw wide conclusions about what changes in Real Power output due are likely for a given ? across the entire North American footprint, as the data is limited to a relatively narrow geographical location, number of facilities, and timeframe. Region-specific studies with more robust data would inspire confidence these changes do not present an undue burden in the way of nuisance event analysis.
R2 & R3 requirements
The time periods in R2 and R3 should be increased to 120 calendar days to allow time to determine the root cause and develop a Corrective Action Plan, especially if OEM support is required.
The stated rationale for the discrepancy between the PRC-004 analysis requirement of 120 days and the proposed PRC-030 requirement of 90 days is that: “The PRC-004 timeframe accounts for extreme weather events such as hurricanes that may affect a very large number of Protection Systems for a given responsible entity”. Additionally it is stated that: “The 120 calendar day period accounts for the sporadic volumes of Protection System operations, and provides the opportunity to identify any Misoperations which were initially missed”
The same extreme weather events that cause numerous PS operations can, and may even likely occur at the same time that unexpected output events occur for IBRs. Typically, it will be the same teams that analyze both of these types of events.
Furthermore, it is unclear on what basis the SDT has determined that 90 days allows sufficient time to provide thorough IBR response analysis as no evidence is presented. IBR proprietary control systems remain a major obstacle to analysis, and will necessitate communication with external vendors which are not bound by the compliance timeframe requirements of the PRC.
The same issues regarding control systems and external vendors will also exist for developing CAPs.

Likes 0	

Dislikes 0	
Response	
The DT finds the thresholds to be reasonable based on the data, expertise and studies that are available and considering system risk. Note that the TR does include some studies outside ERCOT including NREL studies. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days ensures reliability and extending that would not ensure reliability. In the case where it is not possible to obtain information from the OEM in 90 days, the GO could document that information was requested from the OEM and document the best attempt at a root cause based on what they are able to determine from the information available. The DT believes it is important to include a time requirement. The DT considered increasing the time and is holding 90 days to ensure diligence in analyzing and correcting unexpected performance. The CAP should be written in such a manner so as to follow up on data collection that is still in process as well as challenges regarding engagement with OEMs and external vendors.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the comments of the MRO NSRF and the NAGF.	
Likes 0	
Dislikes 0	
Response	
Please see responses to MRO NSF and the NAGF.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	

Document Name	
Comment	

The NAGF has identified several concerns regarding the proposed revisions:

1. *Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.*
2. *Inconsistency between R3 and R4: R3 requires the Corrective Action Plan (CAP) to be provided to the RC, BA, and TOP, while R4 only mentions the RC. This inconsistency was noted as potentially problematic.*
3. *VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.*
4. *Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.*
5. *Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.*

Likes 0	
Dislikes 0	

Response

1. The DT removed the “identifying” qualifier in Requirement R2 and tied the timing of R2 to the event date because as originally written, there was an open-ended timing problem for the GO to identify the event. Without tying the GO’s identification response to the event date, there is a risk of missing events entirely due to lack of information or persistence.

2. The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans. With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve administrative burden on the GO’s when submitting the CAP.

3. Thank you for the recommendation, the team will make this conforming non substantive change removing the word susceptibility for the VSL language and replacing it with applicability along with updating the number to reflect the correct sub-bullet of Requirement R2 2.1.4.

4. The Implementation Plan for PRC-030 includes as the pre-requisite PRC-029 in the latest Implementation Plan. The Implementation Plan from the last draft included language "Where approval by an applicable governmental authority is required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving the standard; or 2) the first day of the first calendar quarter that is twelve (12) months after the effective date of the applicable governmental authority's order approving Reliability Standard PRC029-1, or as otherwise provided for by the applicable governmental authority." under the effective date section in response to the aforementioned paragraph that was removed from the previous version of the Implementation Plan.

5. This concern is outside of the scope of this DT's SAR coverage for this project.

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	

Constellation thinks "Nameplate rating" needs to be clarified as there are many ways to define that especially for solar and storage plant. Recommend adding "at the Point of Interconnection as defined in the interconnection agreement" in R1. Further, although the analysis completion was changed from 45 days to 90 days in R1. Timeframe needs to be adjusted to 120 days to match PRC-004 .

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

1. Nameplate rating was used as the basis of the change (power or amperes) because it is the common reference in NERC and other industry standards. Nameplate was chosen because every generator has a nameplate rating that can be referenced. Nameplate rating is also included as the reference point as it is included in the BES definition.
2. The 120-day timeframe in PRC-004 was intended to cover wide scale weather events such as hurricanes. The DT members feel that 90 days noted in R2 ensures reliability and extending that would not ensure reliability.

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

Answer	
Document Name	

Comment

Duke Energy agrees with and suggest implementation of NAGF comments #1, #3 and #4 identified below:

#1: Substantive change in Requirement R2: The removal of the word "identifying" in relation to the 90-day timeline for real power change events was seen as a significant change that could shorten the response time for entities. Therefore, the NAGF recommends removing the proposed wording change and leaving the language as is from PRC-030 Draft #3 that was approved by industry.

#3: VSL terminology: The continued use of the term "susceptibility" in the Violation Severity Levels (VSLs) was highlighted, despite its removal in previous versions of the standard.

#4: Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards.

Additionally, Duke Energy notes that PRC-030 is dependent on data from PRC-028.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments. Please see responses to #1, #3, and #4 of NAGF's comment. The DT made the decision in earlier drafts to not include PRC-028 as it is not a prerequisite needed for PRC-030. The way the PRC-030 standard is drafted it does not need data dependent on the PRC-028.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with and supports NAGF comments. In addition, Black Hills Corporation is concerned with the standard not defining a time frame for RC, BA, or TO notify GO of a disturbance. Black Hills Corporation's current practice is to maintain a rolling years' worth of data, it is unclear if this would be sufficient for compliance with the standard.	
Likes 0	
Dislikes 0	
Response	
Please see responses to NAGF comments. Thank you for your comments the DT felt it was not necessary to add a timeline to the reliability entities to ensure reliability, the DT discussed with BA, RC, TOP DT members how this process operates. With the current guidance and best practices by the BA, RC, and TOPs the DT felt no timeline was needed.	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	

Comment	
1) Shouldn't another bullet be added in the exclusion list in R1? · Real Power reduction due solely to a RAS (Remedial Action Scheme) Misoperations being analyzed and corrected under PRC-012 Reliability Standard	
Likes 0	
Dislikes 0	
Response	
Thank you for the response and comment, the team based on previous comments received in previous drafts felt these exclusions were necessary to ensure reliability. This would be remedied as it is part of a technical justification in Requirement R2 in the current PRC-030.	
Ruchi Shah - AES - AES Corporation - 5	
Answer	
Document Name	
Comment	
Substantive change in R2 - Standard (1st screenshot) has been updated to remove "identifying" from R2. By making this change the 90 day timeline is effectively shortened during which entities have to analyze the event, because entities will not be able to "identify" events in real time. Implementation plan changes: The removal of a paragraph linking PRC-30 to PRC-29 in the implementation plan was seen as a significant change that could impact the sequential implementation of these standards. Lack of clarity on actions required: There was uncertainty about what actions the RC, BA, and TOP need to take upon receiving the CAP.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. Please see responses to NAGF comments.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	
Comment	
The MRO NSRF thanks the SDT for consideration of these and previous comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the response.	
Marty Hostler - Northern California Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	
If BAs, RCs, and TOPs needed this data then they have had years to request it via their interconnection agreements and market rules.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Requirement R3 mandates that all CAPs or justifications from “performance issues and corrective actions [that] were identified in Requirement R2 Part 2.1.3” be provided “to the applicable RC, BA, and TOp”. However, not all issues and actions from Requirement R2	

were identified or communicated to the GO from the RC, BA, or TOp. As such, only the ones coming from the RC, BA, or TOp should have to be provided back to them and then, only to the one(s) that provided it to the GO, not necessarily to all three. Similar comment to Requirement R4.3 - only the CAP actions resulting from a notification from the RC should have to be reported back to the RC. Also, what about the CAP actions resulting from a BA or TOp notification - shouldn't they be communicated back to them?	
Likes 0	
Dislikes 0	
Response	
The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understanding the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans. With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve administrative burden on the GO's when submitting the CAP.	
Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP would like to thank the SDT for revising R2 to make it clear that the expectations are within 90 days of the event itself, and for replacing the word "applicable" with "associated" throughout the standard in regards to the Functional Entities. On the previous ballot period, the SDT responded to AEP by stating "In the case where a root cause cannot be identified, this would conclude the analysis portion of Requirement R2. However, ***mitigating actions should be implemented*** so that a root cause can be determined for subsequent events, such as correcting inverter logs and insufficient data capture." While AEP agrees in principle that doing so would be a reasonable approach, we do not believe the standard obligations themselves clearly convey such expectations, as this language is not included in the standard nor insight provided within the Technical Rationale. This language needs to be explicitly included in the standard, so that it is fully understood and consistently executed by Functional Entities. In addition, the standard could be further improved by revising it to accommodate for situations when a cause is found, but where an entity is unable to fully mitigate it.	
Likes 0	

Dislikes 0	
Response	
The DT believes that the requirements drafted provide sufficient clarity. However, in response, the DT has provided additional clarifying language in the Technical Rationale.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy continues to request clarification on the determination of what would be a failure vs. weather as related to Requirement 1. FirstEnergy would request an expansion of the threshold criteria that would fall under PRC-030-1, understanding the scan rate is able to detect these changes, these minor occurrences and investigations potentially take the primary focus away from the protection of the BES.	
Likes 0	
Dislikes 0	
Response	
The DT does not expect there to be many weather related events such as change of wind speed or change in irradiance that would cause the facility to meet the threshold requirements related to Requirement R1. Please refer to the analysis provided in the TR document. Please refer to the TR document in response to your comment.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	

Comment	
WECC voted affirmative but offers the following for consideration. Standard comments- Consider spelling out Inverter-Based Resource in the third bullet of Requirement 1 that currently is just "IBR" to be consistent with other Requirements. Consider capitalizing "inverter-based resource" in Requirement R2 Severe VSL. Requirement R3 Lower, Moderate, and High VSLs need to reflect "calendar days" to match the Requirement language (and the Severe VSL language) Implementation Plan comments-The title of Standard PRC-029 is not correct (should be "PRC-029-1 Frequency and Voltage Ride-through Requirements for Inverter-Based Resources"). In the "Background" section first sentence there is a need to update "inverter-based resources (IBR)" and replace the added "Inverter-Based Resources (IBR)" with simply "IBRs". Determine if a hyphen is needed or not for "BPS-connected" as both are used. Need to lower case the "s" in "IBRS" in the last sentence of "General Considerations". Footnote 8 needs edited to remove the first "as" between "such" and "IBRs". Need to lower case the "s" in "IBRS" in the sentence under "Bulk-Electric System IBRs" header. Although allowed, consider consistency in use of "Bulk Electric System" or "Bulk-Electric System" especially when sitting next to each other in document. Suggest simply use "BES IBRs" as the header and the first part of sentence under the "Bulk-Electric System IBRs" header. Consider removal of "Applicable" for the "Applicable Non-BES IBRs" header as it is unnecessary. The definition provides what a Non-BES IBR may be and a Standard would determine the applicability. If the DT thinks "applicable" is necessary, why is it not a modifier for "Bulk-Electric System IBRs" section? It is not clear what the last sentence under the header "Applicable Non-BES IBRs" provides. Note the first part of the sentence (if retained as is) needs corrected to "Applicable Non-BES Inverter-Based Resources." It should be noted within the Implementation Plan and/or Technical Rationale that the Non-BES IBR definition reflects the ROP definition for Category 2 (and does not capitalize "inverter-based resource".) Now, with the "Applicable" modifier, the sentence reads as if there **are more** Non-BES Inverter-Based Resources that are included in the Phased-in Compliance considerations. Suggest removal of "Applicable" and the last sentence. If not, then the DT needs to explain what other "Applicable Non-BES IBRs" are outside of the defined Non-BES IBRs. There is a SAR that is considering "IBR-DER", "Sub-BES IBR", and "Non-Material IBR" definitions but that is in early stages of consensus building.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The DT has considered and made all non-substantive changes in response to your comments wherever is appropriate. The DT notes the applicability is consistent with what is defined in footnote 8 in the Implementation Plan.	

Brian Lindsey - Entergy - 1	
Answer	
Document Name	
Comment	

Implementation Plan:

This is not a phased in implementation plan. Also, Entergy is concerned that the implementation of PRC-030 is dependent on the implementation of PRC-029 which has not been approved yet.

The implementation plan should be 365 days instead of 90 days to allow for any control changes that might be required. A process may need to be added to allow extensions of implementation based on potential supply chain issues.

Requirements:

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

Concerns with having to provide the information to multiple entities.

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

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

Likes 0	

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Dislikes 0	
Response	
The implementation plan notes that "the proposed reliability standard PRC-030-1 includes the analytics and CAPs that complement Project 2020-02, which proposes new Reliability Standard PRC-029-1 addressing Ride-through and performance requirements for IBRs." Additionally, the DT believes that the implementation plan is clear regarding effective dates – as noted in the plan, "Where approved by an applicable governmental authority is not required, Reliability Standard PRC-030-1 shall become effective on the later of 1) the first day of the first calendar quarter that is twelve (12) months after the date the standard is adopted by the NERC Board of Trustees; or 2) the first day of the first calendar quarter that is twelve (12) months after the date Reliability Standard PRC-029-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction." Thank you for the comment around the four second window, there are examples in the technical rationale that further explains examples and what qualifies or how the DT views events in relation to the four second window. Requirement R2 is clear that the GO needs to provide requested data to the requesting reliability entity. The RC, BA and TOP are ultimately responsible for the operation and security of the BES and BPS. As such they are accountable to know and understand the limitations and issues in the electric system, requiring knowledge of respective Corrective Action Plans. With Requirement R4, the DT felt the CAP only had to go to the RC for the purposes of updating the timelines. This was to relieve the administrative burden on the GO's when submitting the CAP. PRC-004 requires 60 days to develop a CAP and from comments received the DT determined to follow a similar timeline as PRC-004 when developing the CAP for PRC-030, these dates ensures reliability in PRC-004 and the team wanted to make sure that this continues to ensure reliability in PRC-030 .	

End of Report