# Technical Rationale

## Project 2023-02 Analysis and Mitigation of BES Inverter-Based Resource Performance Issues
## Reliability Standard PRC-030-1 | September 2024

## PRC-030-1 – Unexpected Inverter-Based Resource Event Mitigation

**Rationale for Applicability Section**

The functional entity responsible for identifying, analyzing, and mitigating unexpected Inverter Based Resources (IBR) performance is the Generator Owner (GO). The Generator Operator (GOP) is not included because of the accountability and coordination issues introduced by listing both GO and GOP as responsible functional entities. The GO is accountable for changes and improvements to the IBR and facilities necessary to mitigate performance problems. Further, this standard intentionally did not include requirements for the Balancing Authority (BA), Reliability Coordinator (RC), and Transmission Operator (TOP) because other standards (e.g., EOP-004) place requirements on these entities for system level events.

**General rationale**

Aligned with the Project 2023-02 Standards Authorization Request (SAR), the Requirements are structured to identify, analyze, and mitigate IBR performance issues. The SAR discusses how a series of NERC disturbance reports have "identified the undesired performance of bulk power system (BPS)-connected inverter-based resources (IBRs) during grid faults, and have elaborated on the systemic and significant BPS reliability risks that these pose". [1], In particular, IBR performance during events has included tripping or momentary cessation that is unexpected, unwarranted, and poses reliability challenges.

Requirement R1 defines how events are to be identified, along with exceptions that should not be identified. Requirement R2 requires analysis of identified events, with specific elements assessed as described in subparts. Requirement R3 requires a Corrective Action Plan (CAP) or technical justification when corrective actions are needed. Finally, R4 requires mitigation of the performance risk through CAP implementation. The flow of these requirements is summarized in Figure 1.1.

[1] *Analysis and Mitigation of BES Inverter-Based Resource Performance Issues Standard Authorization Request, at p. 1 (accepted August 23, 2023) (referencing [Event Reports (nerc.com)](Event Reports (nerc.com)))*

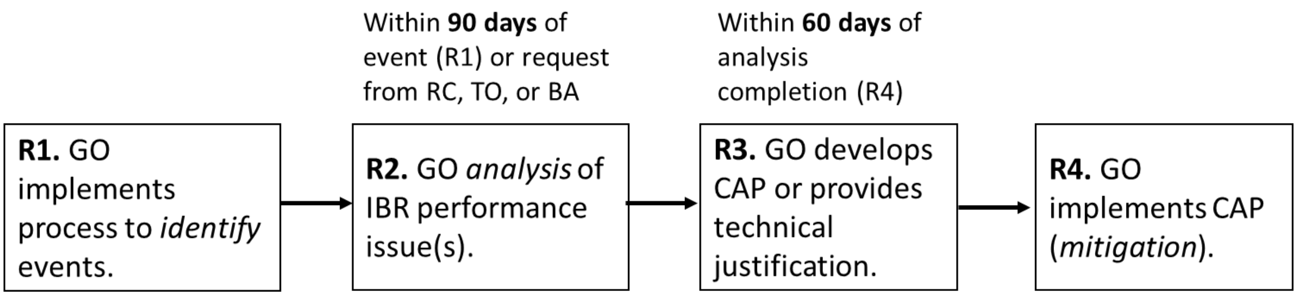



Figure 1.1: Relationship of Requirements in PRC-030-1

The Requirement R1 contains thresholds for identifying events with sudden changes in Real Power. Figure 1.2 depicts the threshold criteria and logic used in Requirement R1, along with additional details of process flow in Requirement R2.

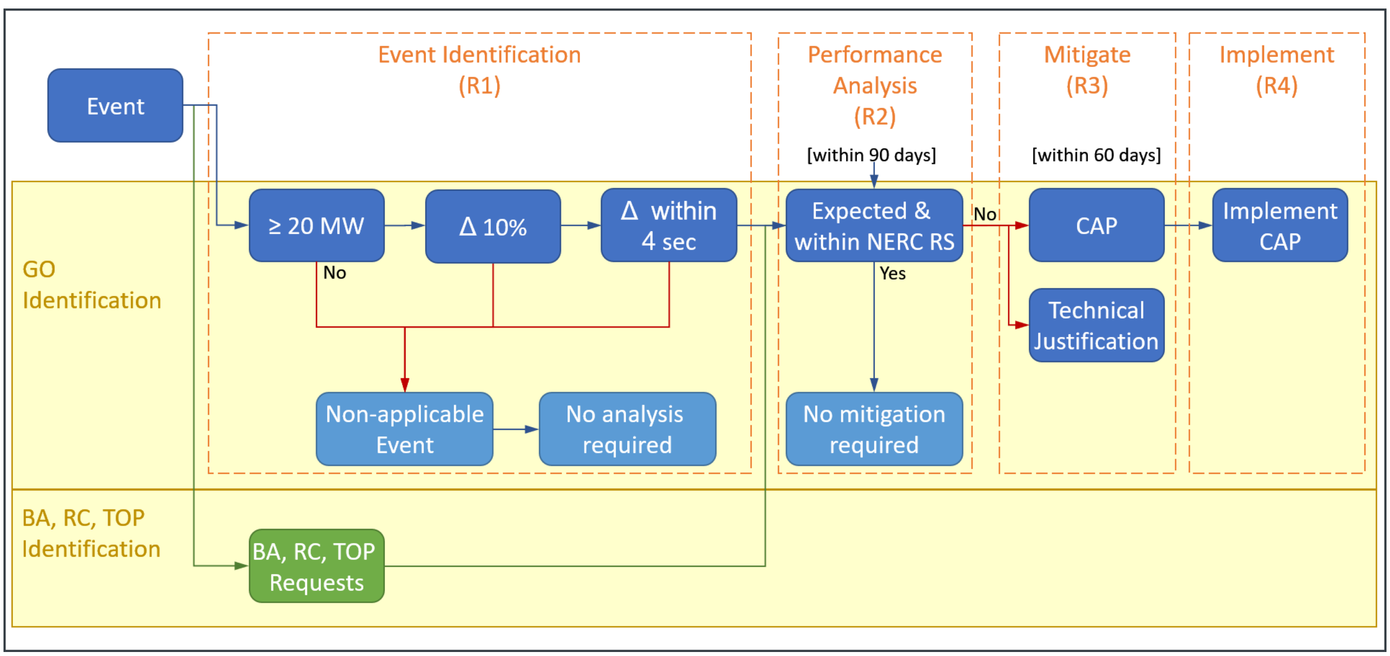



Figure 1.2: PRC-030-1 Flowchart

## Rationale for Requirement R1

The intent of Requirement R1 is for the Generator Owner (GO) to implement a documented process to self-identify events that are sufficiently large to warrant an analysis of IBR performance for the identified event. For that reason, the Drafting Team included the 20 MW minimum threshold, which is a common cutoff for other Reliability Standards, such as MOD-025, to reduce the number of potential events. NERC Category two in the ROP, entity registration section references 20 MVA as a significant threshold.

While the GO should consider both active and reactive power responses when an analysis is required, only Real Power is used as a threshold to trigger analysis. Real Power was selected as the monitored parameter to make implementation feasible across IBR plant designs and back end software system (e.g., SCADA). MW and Mvar are monitored on the SCADA software, while MVA is typically not present. The Drafting Team (DT) went with MW instead of MVA due to Real power loss being the primary concern in IBR events.

The thresholds for event identification in Requirement R1 provide a two-tier approach depending on the size of the IBR facility. The table below shows the two tiers and the thresholds that should be used to identify events. In addition, all unexpected events in which there is a complete loss of MW output, or active drops to 0 MW, should be identified regardless of plant size and output. This of course excludes planned ramp downs, and all other exclusions listed in Requirement R1 (solar end of day ramp down, planned outages, loss of connecting transmission facilities, Misoperations identified in PRC-004, etc.).

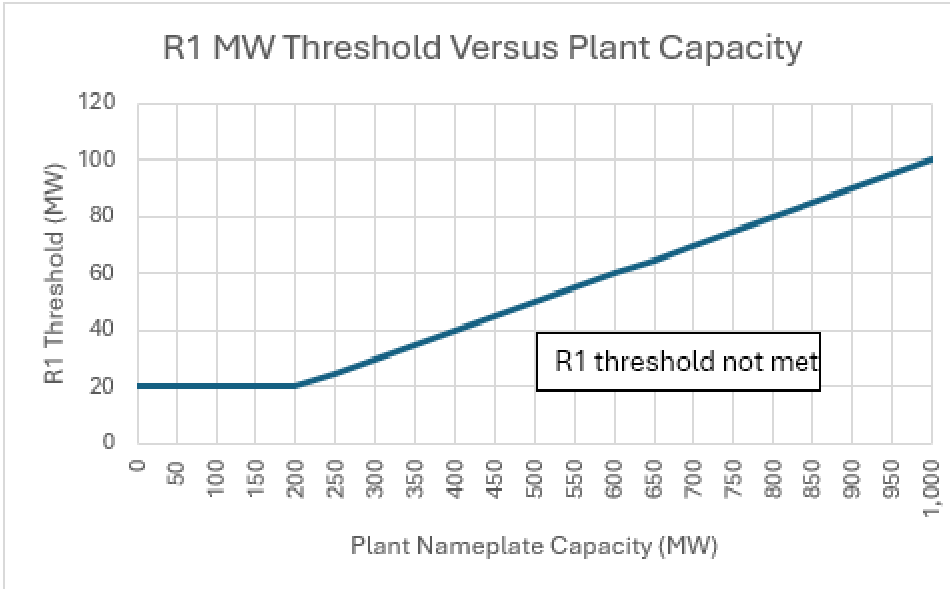
| **Facility Nameplate Rating** | **Threshold** |
|---|---|
| 200 MW or less | 20 MW |
| Greater than 200 MW | 10% of Nameplate Rating (e.g. 30 MW for 300 MW Facility) |

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.

The 10% of nameplate rating for magnitude of Real Power change event threshold was chosen to be large enough to screen out small Real Power changes but low enough to detect events that should be analyzed for reliability purposes. The percent change is intended to address facilities with greater than 200 MW nameplate rating where 10% is a significant change, otherwise the 20 MW threshold sets a minimum threshold for event identification. The 20 MW minimum change threshold causes the 10% change to only apply to 200 MW facilities and above.
For smaller capacity facilities, the use of only a percent change as the screening criteria would lead to identification of disturbances that are not likely to be significant for analysis.

To restate the criteria another way:
- For plants with 0 – 200 MW gross nameplate rating, the change must be at least 20 MW,
- For plants with 200 MW gross nameplate rating and larger, the change must be at least 10% of the gross nameplate rating.

The criteria could be charted as depicted below.




Requirement R1 Threshold met

The purpose of the two limits is to make the trigger points manageable for both large and small facilities. The Drafting Team (DT) recognizes that as the plant size grows, so does the trigger threshold, which is why the threshold was set at 10% rather than something larger, like 20%. While the GO would not be required to identify events below the 10% threshold for large plants, the Reliability Coordinator (RC) is explicitly given the option to request a review in the requirement.

The DT revised the wording of Requirement R1 to clarify that the DT's intent is at least 20 MW for facilities with a nameplate rating of 200 MW or less and at least 10% change for facilities with a nameplate rating over 200 MW. While the DT considered the existing criteria sufficient, a complete loss of the facility was also included as a Requirement R1 condition.

At one point, the DT considered using the terms "sudden" and "unexpected", but that created uncertainty and concerns about consistent application. Therefore, the DT chose to bound the initial change at event onset to a four second timeframe.

The various SCADA scan rates in use at ISOs/RTOs as well as NERC standard minimum required scan rates were considered in selecting four seconds. SCADA monitoring is a likely method for monitoring Real Power changes. Power changes that occur and recover within one scan are not expected to be detected by the Requirement R1 process implemented by GOs. The four seconds was not intended to define the scan period, but only to characterize the change as sudden when considering information on monitoring capabilities across the industry. If a facility is using a scan rate of four seconds or greater to monitor Real Power output, the GO should use the change in Real Power output in one scan rate to identify events meeting Requirement R1 criteria. It should be noted that using longer time periods or scan rate could lead to a need for more sophisticated event screening or may otherwise lead to identification of more invalid events that occur on slower timescales.

The intention of the four seconds was to limit the time within which the change in Real Power is calculated. The DT also considered that IBR generation plants following normal operation dispatch commands tend to move more slowly. For example, using the 20 MW for four seconds, the change rate is 5MW/sec, or 300 MW/min. Lower ramp rates would not be expected to meet the Requirement R1 criteria.

The following set of charts, in Figure 1.4, are examples of expected event scenarios and whether they meet the Requirement R1 criteria.

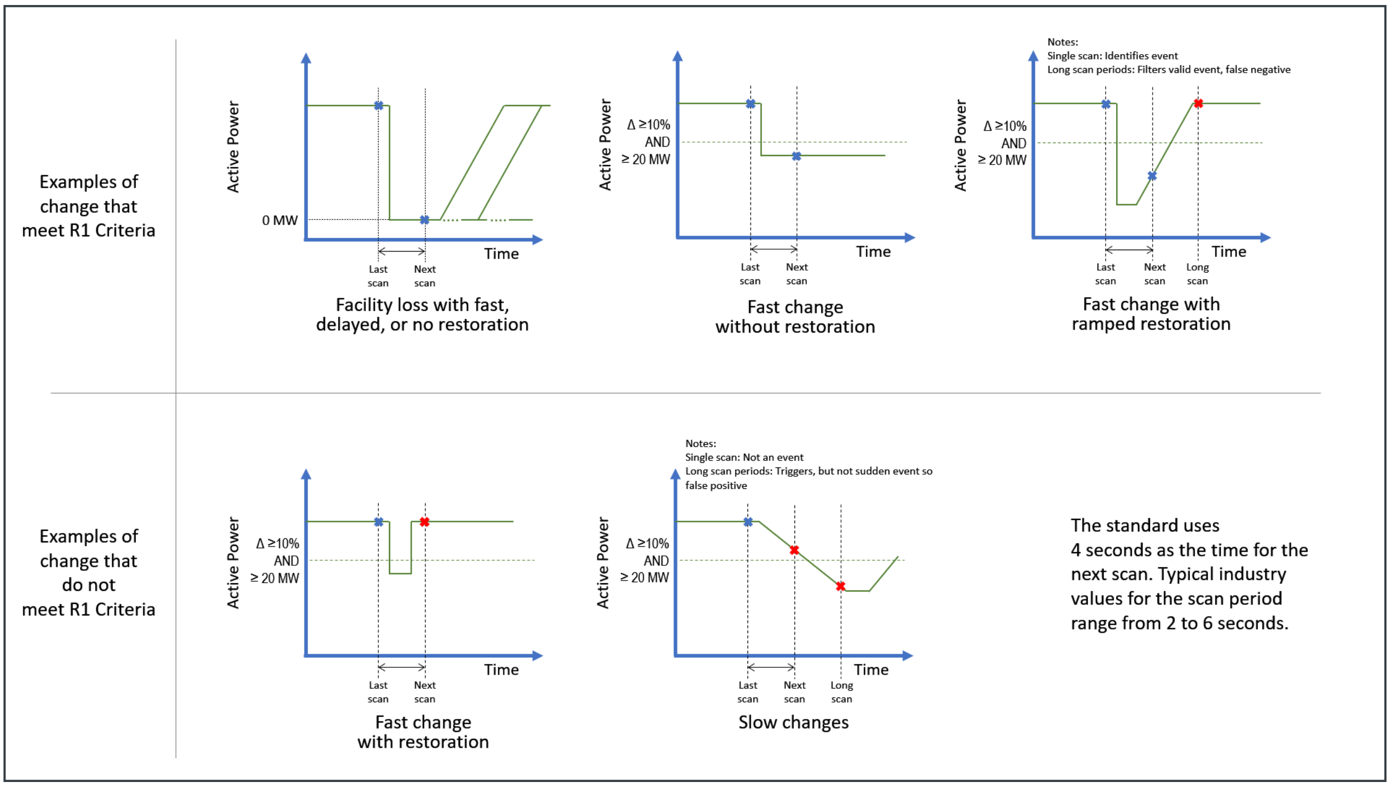



Figure 1.4: PRC-030-1 Flowchart

Due to concern voiced by industry that the thresholds defined in Requirement R1 could be often exceeded during the normal operation of an IBR facility, the DT examined three IBR facilities in Texas to determine the frequency of such events.

*Solar facility in West Texas with 160 MW nameplate rating:*
The DT analyzed one year of data encompassing all of 2023 and found five instances in which the facility changed 20 MW or more within a four second period. All five instances were related to ride-through performance issues previously identified by the Reliability Coordinator. There were zero events in which

Real Power changed 20 MW or more within a four second period due to change of irradiance, ramping due to dispatch, or other reasons listed as exclusions to Requirement R1.

*Wind facility in Texas Panhandle with 300 MW nameplate rating:*
The DT analyzed one year of data encompassing all of 2023 and found zero real events in which the facility changed 30 MW or more within a four second period. There were several events that were triggered due to dropouts of telemetry from the facility, but telemetry from the Point of Interconnection verified that there were no actual drops in Real Power from the facility at the time.

*Solar Facility in Central Texas with 500 MW nameplate rating:*
The DT analyzed one month of data for June 2024 and found seven events in which the facility changed 50 MW or more within a four second period, the first four of these events appear to be caused by curtailment issues. The plant was either being curtailed or was released from curtailment at the time which four of the seven events were detected. One of those events showed a large increase of irradiance at the time, but it is unclear if the change of irradiance alone caused the sudden increase in generation or if it was due to improper curtailment ramp rates, or a combination of the two. Two of the other events were related to large oscillations lasting up to an hour in which peak to peak magnitude of the oscillation exceeded 50 MW. The last event was due to a Power Plant Controller issue that caused a sudden drop in Real Power of 246 MW and was previously identified by the Reliability Coordinator. Under Requirement R1 requirements, three of the seven events would meet criteria and need to be analyzed in Requirement R2. The table below summarizes the results:

| Date/Time | Four second MW change | Increase/ Decrease | Significant Irradiance Change | Cause | Should be Analyzed in R2 |
|---|---|---|---|---|---|
| 6/4/2024 1:25:00 PM | 83 | Increase | Yes | Curtailment issue/ Irradiance change? | No (Resource dispatch and/or change in irradiance exclusion) |
| 6/4/2024 5:00:00 PM | 192 | Increase | No | Curtailment released | No (Resource dispatch exclusion) |
| 6/14/2024 8:02:00 AM | 57 | Increase | No | Curtailment issue | No (Resource dispatch exclusion) |
| 6/14/2024 11:36:00 AM | 138 | Increase | No | Curtailment issue | No (Resource dispatch exclusion) |
| 6/17/2024 11:45:00 AM | 246 | Decrease | No | Plant controller issue | Yes |
| 6/23/2024 12:30:00 PM | 50 | Both | No | Oscillation Event | Yes (peak to peak magnitude >50 MW observed) |
| 6/26/2024 4:00:00 PM | 78 | Both | No | Oscillation Event | Yes (peak to peak magnitude >50 MW observed) |

The DT also analyzed data covering one month from four facilities in Hawaii and found only one event that exceeded thresholds in Requirement R1. Since facilities in this area are generally smaller, all four facilities analyzed were less than 200 MW in nameplate rating, so a 20 MW threshold was used for analysis. The DT also looked at an extended time period of 60 seconds, and as expected, more events were identified with the extended time period.

| Plant # | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Technology | Wind | PV | PV/BESS (AC Couple) | BESS Standalone |
| Facility Nameplate Rating (MW) | 69 | 46 | 39 | 135 |
| # of event<br>(4 second, >20 MW) | 0 | 0 | 0 | 1 (cause unknown) |
| # of event<br>(60 second, >20 MW) | 0 | 0 | 0 | 8 |

Due to the above analysis, the DT believes the thresholds in Requirement R1 would rarely trigger events due to normal operation of an IBR facility if the facility is operating as expected. The DT only found one possible instance of a facility exceeding the thresholds due to change of irradiance and wind speed, and it was likely caused by improper curtailment ramp rates programmed into the Power Plant Controller. In addition, the DT reviewed papers published by NREL on Solar PV Variability at Small Timescales and Variability of Wind Power Output, which concludes that change in irradiance and wind speed would not have large impacts to changes in output within a narrow timeframe such as a four second period.

The intention of the four second period was to specify what constitutes a sudden change in power, similar to the types of Real Power loss events described in NERC Disturbance Event reports. The DT considered using the term "scan period" to define the change period, because this scan period is the basis of the time, but chose to stay with the four second time specification. Four seconds is a common industry practice, MISO's scan rate, which is one of the longest, has a time duration of four seconds. The four second threshold is meant to provide a significant exclusion because the change must occur quickly, within that time. Increasing the time effectively reduces the rate of change and would identify more events than a four second window. The intent is to exclude from review slow power changes expected with normal operations (e.g., variable output from weather, dispatch, planned outages, testing) or expected responses (e.g., loss of interconnection facilities), which were defined as bullet points to Requirement R1.

The standard four second time only applies to the period of calculating the Real Power change, such as a sudden drop, to be considered valid events identified under Requirement R1. This time does not limit or imply any duration for the entire event. While the change must occur within the four second timeframe, the plant response may take tens of seconds or even minutes. The standard does specify or limit that time period.

The term "changes in Real Power" encompasses both sudden decreases (i.e., loss of output) and increases (i.e., additional consumption) 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 and suddenly increase Real Power draw.

*Photovoltaic (PV) example 1 – qualifying:*
PV facility with gross nameplate rating of 220 MW is operating with active output of 80 MW. During a transmission system fault event,[2] the plant exhibits a near instantaneous Real Power output drop to 50 MW.

The change in apparent power in under four seconds is 30 MW, which exceeds 22 MW, the greater of 10% of the plant's gross nameplate (22 MW) or 20 MW. This IBR performance event is required to be captured by the GO's process implemented in Requirement R1.

*PV example 2 – non-qualifying:*
PV facility with gross nameplate rating of 80 MW is operating with active output of 60 MW. During a transmission line fault event,[1] the plant exhibits a near instantaneous Real Power output drop to 42 MW.

The change in apparent power in under four seconds is 18 MW, <u>not</u> exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

*Battery Energy Storage System (BESS) example 1 – qualifying:*
BESS facility with gross nameplate power output rating of 80 MW is operating as a load drawing 50 MW. During a power plant controller (PPC) malfunction event of the BESS facility, the PPC incorrectly estimates system frequency sending an incorrect frequency response signal causing the plant to exhibit a near instantaneous change in real power to 10 MW injection.

The change in apparent power in under four seconds is 60 MW, which exceeds 20 MW, the greater of 10% of the BESS gross nameplate (8 MW) or 20 MW.
This IBR performance event is required to be captured by the GO's Requirement R1 process.

*BESS example 2 – non-qualifying:*
BESS facility with gross nameplate power output rating of 80 MW is outputting 40 MW. The BESS facility is curtailed by the Reliability Coordinator such that the plant exhibits a near instantaneous Real Power decrease to 15 MW.

The change in apparent power in under four seconds is 25 MW, exceeding 20 MW, the greater of 10% of the plant's gross nameplate rating (8 MW) or 20 MW. However, the change in apparent power is the result of the Reliability Coordinator curtailment which is an exempt event per Requirement R1. This IBR performance event is <u>not</u> required to be captured by the GO's Requirement R1 process.

[2] The transmission line fault is assumed not to be on the line connecting the IBR to the system, but rather is a fault remote from the IBR.

**Rationale for Requirement R2**

Requirement R2 requires analysis of events that meet Requirement R1 thresholds. Requirement R2 also provides an alternative path of event identification by the Balancing Authority (BA), Reliability Coordinator (RC), or Transmission Operators (TOP). It is anticipated that some events would only be detected by one entity, but the combination of both identification methods would better identify events potentially posing reliability challenges.

Requirement R2 allows 90 days to analyze expected versus actual IBR responses to place an emphasis on diligent resolution, while still allowing enough time to conduct an analysis and identify causes. Ninety days allows adequate time for GO to interact with manufacturers and examine capabilities of equipment. In establishing this timeframe, the DT considered the PRC-004 timeline of 120 days, recognizing important differences between the application of these standards. PRC-004-4(i) Technical Rationale states "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".[3] 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. The volume of IBR exposed to potential expected operation is anticipated to be lower when compared to Protection Systems and therefore a shorter timeframe is appropriate for PRC-030. The 90-day period starts from the event date for GO-identified performance issues resulting from Requirement R1 or upon request from the Balancing Authority, Reliability Coordinator, or Transmission Operator regarding IBR responses identified during system events.

Requirement R2, Part 2.1 includes subparts to analyze performance during a Real power change event. Requirement R2, Part 2.1.1 requires identification of the root cause. Requirement R2, Part 2.1.2 requires that the facility's Ride-through performance including reactive power response is documented (Requirement R2, Part2.1.2). Requirement R2, Part 2.1.3 requires that the GO assess the performance issue(s) and determine whether corrective actions are needed. Requirement R2, Part 2.1.4 requires that the GO consider the applicability of the root cause to its other IBR facilities. Collectively, the subparts define the minimum features required as part of an effective analysis. Requirement R2, Part 2.2 closes the communication loop with Balancing Authority, Reliability Coordinator, and Transmission Operator entities, should these entities request analysis results.

When the root cause cannot be identified or a root cause is identified but the GO cannot fully mitigate it, then it is expected the GO will continue to work with the associated reliability entities and Original Equipment Manufacturers to follow up on such instances and deploy mitigation plans when these become available. The GO will continue to coordinate with associated reliability entities through improvements to root cause analysis and CAPs until such a time the mitigation plans are in place. Such improvements include better data capture, and fault logging capabilities for subsequent future events.

[3] Standard PRC-004-4(i) – Protection System Misoperation Identification and Correction. Available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/PRC-004-4(i).pdf

**Rationale for Requirement R3**

Should Requirement R2 determine a need for corrective actions, Requirement R3 requires a CAP or technical justification be developed within 60 calendar days of completing the analysis in Requirement R2, as identified in Requirement R2, Part 2.1.3. If Requirement R2 did not identify the need for corrective actions, then no action is required under Requirement R3.

Resolving the causes of IBR performance issues benefits BPS reliability by preventing recurrence. The CAP is an established tool for resolving operational problems. The NERC *Glossary* defines a Corrective Action Plan as, “A list of actions and an associated timetable for implementation to remedy a specific problem.” Since a CAP addresses specific problems, the determination of what went wrong needs to be completed before developing a CAP. When the IBR Performance issue cause(s) is identified in Requirement R2 or Requirement R3 requires Generator Owner(s) to develop a CAP or provide a technical justification that addresses why corrective actions will not be applied nor implemented. The CAP is provided to the Reliability Coordinator, Balancing Authority, and Transmission Operator so that these entities 1) gain information potentially relevant to recent system events, and 2) can account for potential IBR performance issues in operational risk assessments.

This standard recognizes there may be multiple causes for IBR performance issues. In these circumstances, the CAP would include a remedy for the identified causes. The CAP may be revised if additional causes are found; therefore, the entity has the option to create a CAP to correct multiple causes of an IBR performance issue. The 60-calendar day period for developing a CAP or technical justification is established based on industry experience which includes operational coordination timeframes, time to consider alternative solutions, coordination of resources, and development of a schedule.

The development of a CAP is intended to document the specific corrective actions needed to be taken to prevent IBR performance issues from reoccurring, the timetable for executing such actions, and an evaluation of the CAP’s applicability to the GO’s other IBR including those at other locations. The evaluation of these other IBR with similar designs aims to reduce the risk and the likelihood of similar IBR performance issues in other IBRs. The GO is responsible for determining the extent of its evaluation concerning other IBRs and locations. The evaluation may result in the GO including actions to address IBR at other locations or to provide a technical justification that addresses why corrective actions will not be applied nor implemented.

Acceptable technical justification for not performing corrective actions is expected to primarily have two characteristics:

1) interconnection requirements on IBR performance extending beyond those in place at the time of interconnection; and

2) it would require significant material modifications/qualified change.

Technical justifications for not performing corrective actions do not relieve the GO from compliance with other standards (i.e., PRC-029-1 Ride-Through) to the extent that other standards are applicable.

**Rationale for Requirement R4**

Requirement R4 requires that each applicable GO implement the CAP developed in Requirement R3, as applicable, to mitigate deficiencies identified in Requirement R2. In the NERC *Glossary*, a CAP is: "A list of actions and an associated timetable for implementation to remedy a specific problem."

A CAP can be modified if necessary to account for adjustments to the actions or scheduled timetable of activities. If the CAP is changed, the entity must notify the applicable Reliability Coordinator(s)~~, Transmission Operator(s), or Balancing Authority (s)~~. The entity must also notify applicable RC(s) when the CAP has been completed. The implementation of a properly developed CAP ensures that causes of unexpected changes in IBR power output are mitigated in a timely manner.

An IBR deficiency may require the Reliability Coordinator to impose operating restrictions so the system can operate in a reliable way until the CAP is completed. The possibility of such operating restrictions should incentivize the entity to complete the CAP as quickly as possible.