Technical Rationale for Reliability Standard PRC-019-3

September 2022

PRC-019-3 – Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection

Introduction

This document is the technical rationale and justification for Reliability Standard PRC-019. It includes the rationale for changes in the current proposed version (PRC-019-3). The intent of this document is to provide stakeholders and the ERO Enterprise with an understanding of the revisions, technology, and technical concepts of Reliability Standard PRC-019-3, as well as the rationale or justifications for such revisions, both the currently proposed and historical revisions from previous versions, if applicable. This is not a Reliability Standard and should not be considered mandatory and enforceable.

Background

PRC-019-2 addresses the reliability issue of miscoordination between generator capability, control systems, and protective functions. However, the standard was developed with a bias toward synchronous generation and does not sufficiently outline the requirements for all generation resource types. While dispersed power producing resources, also known as inverter based resources (IBR), are currently included in the applicability of PRC-019-2, additional clarity is needed in specifying the aspects of dispersed power producing resources that should be coordinated. There are also issues within PRC-019-2 regarding synchronous generation that need to be corrected or clarified to remove ambiguity. These comprehensive updates align with the intent of the standard.

Additionally, the System Analysis and Modeling Subcommittee (SAMS) developed the *Applicability of Transmission-Connected Reactive Devices* white paper and an associated standard authorization request (SAR), which was approved by the Planning Committee on February 11, 2020. The SAR outlined recommended revisions to PRC-019-2 to augment the applicability section and requirement language to include (non-generation) transmission connected reactive resources – such as flexible alternating current transmission system (FACTS) devices and high voltage direct current (HVDC) terminal equipment.

Rationale for Applicability Section

Functional Entities

The purpose of PRC-019-3 is to verify coordination of generating unit or Facility voltage regulating controls, limit functions, equipment capabilities, and protective functions. The two functional entities that play a role in PRC-019-3 requirements and have an obligation to comply with them are:

- Generator Owner
- Transmission Owner

The Generator Owner and Transmission Owner are responsible for coordinating the voltage regulating system controls, with the applicable equipment capabilities and settings of the applicable protective functions, as described in Requirement R1.

The Generator Owner and Transmission Owner are responsible to update the protection coordination study upon pertinent changes being made, as described in Requirement R2.

Facilities

A Facility that would need to meet the requirements in this standard and be considered an "applicable Facility" falls under the characteristics defined by the NERC Bulk Electric System (BES) Definition Inclusion I2 and I4 for generating facilities or Inclusion I5 for a synchronous condenser. This Facilities Applicability is consistent with most other NERC reliability standards being tied to BES-qualified units. The proposed standard links applicability to the BES definition (as opposed to defined rating or other thresholds) to be sure that now and in the future, should the BES definition be modified, the standard is consistent with applicable BES facilities. This avoids the need to modify the standard if definitive thresholds are specified and the BES definition is modified.

FACTS devices and HVDC equipment

The SAMS *Applicability of Transmission-Connected Reactive Devices* white paper, and an associated SAR, outlined a recommendation for revisions to PRC-019-2 to augment the applicability section and requirement language to include (non-generation) transmission connected reactive resources – such as FACTS (static VAR compensator and static compensator) devices and HVDC (voltage source converter VSC and line-commutated converter) terminal equipment. The standard drafting team (SDT) evaluated the recommendation made in the white paper and SAR, and resolved not to add them as Applicable Facilities for PRC-019-3. Though there may be some technical merit to adding FACTS devices and HVDC terminal equipment as Applicable Facilities, the details of and interrelationship between the voltage regulating controls, limiters, and protective functions are relatively unknown. The SDT is not aware of any objective evidence that FACTS devices and/or HVDC Facilities pose a known BES reliability risk, such as findings from a NERC event or disturbance report, Lesson Learned, mis-operation trends, etc. Additionally, the SDT noted that these technologies are designed, engineered, and implemented by a common original equipment manufacturer, comprehensive protection system testing occurs during commissioning, and changes to the equipment after commissioning are infrequent. If future experience identifies an emerging reliability risk with these technologies, the scope of the SAR should be revisited to add the technologies as PRC-019 Applicable Facilities, and Requirement R1 be updated for any technology specific language.

Rationale Requirement R1

The periodicity for Requirement R1 was changed from five to six years to better align with the periodicity of PRC-005. PRC-005-6 Table 1-1 for unmonitored protective relays requires the verification of settings every six years for unmonitored relays or 12 years for monitored relays. By changing the R1 periodicity from five to six years for the verification of coordination, PRC-005 settings verification and PRC-019 coordination verification have the opportunity to be aligned, reducing the fieldwork and interfaces with protective relays.

The wording around Protection System and protective functions was revised to provide clarity on coordination requirements. The current definition of Protection System is written specifically for "Protective relays which respond to electrical quantities" and does not explicitly include protective functions. The intention of the SDT is that both protective functions that exist in Protection Systems, like a traditional protective relay, and protective functions that exist in control systems and replicate the behavior of a protection system device to mitigate the consequences of an event that exceeds equipment design basis must be coordinated.

Footnote 1: The SDT added this footnote to clearly describe the main power transformer at dispersed power resource (IBR) Facilities.

Footnote 2: The SDT added this footnote to clearly describe the generator step-up transformer at dispersed power resource (IBR) Facilities.

Footnote 3: The SDT position is that studies considering the coordination for reliability should be performed with settings actually installed in the field. Coordination based on settings that are planned as part of a project cannot be considered to accurately represent the actual coordination of equipment that is in-service.

Footnote 4: This footnote was added to clarify the term protective function. Protective functions can include both protective functions that exist in Protection Systems, like a traditional protective relay, and protective functions that exist in control systems and replicate the behavior of a protection system device to mitigate the consequences of an event that exceeds equipment design basis.

Requirement R1.1

The revisions to Requirement R1.1 include the removal of the steady state stability limit (SSSL) language for protection coordination. There are two methods to evaluate the SSSL of a synchronous generator. The common method is to calculate the SSSL while the excitation control system voltage regulator is in the manual voltage control mode. This is commonly referred to as the manual SSSL. The alternative and more complicated method consists of complicated equations and software analysis to determine the SSSL while the excitation control system voltage regulator is in the automatic voltage control mode. This alternative methodology is referred to as the dynamic SSSL. The dynamic SSSL provides more operational capability since this curve will take into account the changes within the generator internal voltage as the system voltage deviates. The manual SSSL is a conservative analysis that assumes a constant field winding current regardless of fluctuations in the system voltage.

The PRC-019 requirement language specifically instructs entities to assume the voltage regulator is in the automatic voltage control mode. However, the previous guidance and graphical representation within PRC-019 was for the evaluation of the manual SSSL. These two concepts are in conflict in terms of the PRC-019 coordination requirements. Historically, the manual SSSL curve has been used as a conservative method for developing the underexcitation limiter. However, it should not be required to develop protection characteristics based on a fictitious curve while the voltage regulator is in the automatic voltage control mode.

Requirement R1.2

Historically, generation voltage control has typically occurred at the terminal of a synchronous generator. In this scenario, the voltage control system is making decisions based on internal functions and systems downstream of the terminal of a generator. Hence, the PRC-019-1 draft language reflected the coordination of systems we historically understand and has been established within the industry through the Institute of Electrical and Electronics Engineers, manufacturers, etc.

As the IBR industry evolved, it became more evident that IBR generating Facility voltage control is drastically different from synchronous generation. Typically, an IBR generating Facility will use a power plant controller (PPC) to regulate the generation output of the entire Facility. During steady state conditions, the PPC will measure the voltage on the high side of the main power transformer (e.g. transmission system voltage) and send generation output commands to the individual inverters within the generating Facility. For voltage excursions, the PPC may enter a fault ride-through mode and relinquish generation output control to the individual inverters.

For IBR there can be multiple control modes. PRC-019-3 Requirement R1.2 was drafted using the assumption that the inverters and/or PPC are operating in Q-priority/voltage control mode. In Q-priority/voltage control mode, PPC or individual inverters modulate their output when the voltage at the point of voltage regulation deviates from a predefined magnitude (e.g. 1.0 per unit). The point of voltage regulation is the electrical location where the PPC/inverter receives its electrical input, and this location may differ for inverter applications. When the system voltage decays then the inverter will reduce the real current output and increase the reactive current output in an effort to boost system voltage. When there is high system voltage, the inverters will reduce the real current output and absorb reactive current from the system to reduce the system voltage to an acceptable level.

Requirement R1.2 was added to provide more specific protection system coordination language for IBR technologies. Requirement R1.2 language is written with respect to the unique voltage control methodology within an IBR generating Facility. Coordination between voltage control, protective functions, and equipment capability will have to occur throughout the entire generating Facility, since voltage regulation typically occurs at the high side of the main power transformer during steady state conditions. Therefore, the coordination required in PRC-019-3 must occur from the point that the PPC regulates voltage down to the individual inverters in order for the Facility to provide reliable operation to the grid.

When evaluating protection settings for IBR generating facilities, the protection coordination study should consider the voltage differences between where the protection is measuring voltage and the point of voltage regulation. When using voltage protection schemes it is understood through engineering theory that the voltage drop throughout the generating Facility may need to be accounted for to properly coordinate protection functions. Resources/circuits that will create significant voltage drop may cause a miscoordination of voltage protection schemes that do not have adequate margin. This engineering methodology aligns with the voltage protection guidance provided in PRC-024. The engineering philosophies within PRC-019 and PRC-024 should align since there is overlap between the voltage protection requirements of these standards.

Rationale for Requirement R2

As stated in the SAR, the PRC-019-2 Requirement R2 language could be interpreted in different ways. For instance, if an entity identifies ("following the identification") or implements ("following the implementation") a change to systems that affects PRC-019 coordination, they could wait up to 90 days to perform the coordination analysis. This poses a reliability gap since this allows an entity to make changes to the systems identified within PRC-019, and place the unit back into service without checking coordination. At this time, all existing generation facilities should already meet the coordination requirements of PRC-019-2. Entities should not allow contractors/employees to make modifications to systems that affect PRC-019 coordination without having intimate knowledge of these modifications and their impacts. Therefore, any changes that affect PRC-019 coordination should be evaluated prior to implementation of systems, equipment, or settings changes. This language is consistent with PRC-027-1, Requirement 1.3.3., which states, "Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation." The revised Requirement R2 language removes the 90-day reliability gap in which an entity may operate in an uncoordinated manner. Additionally, the revised Requirement R2 language allows the entity up to 90 calendar days after the return to in-service date to update associated coordination documentation. This 90 calendar day period allows time for documentation to be updated for minor discrepancies in firmware, settings or equipment changes that do not result in a miscoordination as outlined in Requirement R1. Entities are still required to perform a coordination study in accordance with R1 prior to the implementation of these changes. If the entity discovers that the implemented changes (as-left settings) are drastically different compared to the as-studied changes/settings, then a miscoordinatation could result and Requirement R1 would no longer be met.

Lastly, the systems, equipment, and settings changes specific to IBR, power plant controller control system firmware, and settings changes were added to the list of potential changes that would require an updated protection system study. If an entity determines or is advised that a particular change made to systems, equipment, or settings <u>will not affect</u> the coordination described in Requirement R1, then coordination need not be performed. The SDT chose specific language in R2 to meet this intent, which states "Each Generator Owner and Transmission Owner shall perform the coordination described in Requirement R1 prior to implementation of systems, equipment, or settings <u>changes that will affect</u> the coordination described in Requirement."

Rationale for Attachment 1

The intent of this section is to identify which equipment capabilities, control functions, and protective functions need to be coordinated at a minimum. This section adds clarity to the industry for some of the functions that may be utilized for voltage control and protection coordination.

For synchronous generating units, voltage/VAR limit settings within a distributed control system was added to the list of items that need to be coordinated. Control functions consist of more than just "limiters" for a generator. Voltage or VAR control settings that will prevent a generator from outputting additional VARs to the system function in the same manner as a traditional limiter function. Thus, voltage/VAR limiting settings within a control system (e.g. distributed control system, etc.) should be treated as control functions since these two functions will operate in a similar manner.

The existing language within the reference section was dominated by synchronous generation functions. A section was added to highlight some of the control and protection functions that may be utilized within an IBR generating Facility.

Example graphical representations, which were part of PRC-019-2, Section G, have been moved to PRC-019 Implementation Guidance (IG), since they were specific examples or approaches of how a registered entity could demonstrate compliance with the standard. These examples included Attachment 1 (Example of Capabilities, Limiters, and Protection on a P-Q Diagram at nominal voltage and frequency), Attachment 2 (Example of Capabilities, Limiters, and Protection on an R-X Diagram at nominal voltage and frequency), and Attachment 3 (Example of Capabilities, Limiters, and Protection on an Inverse Time Characteristic Plot). These revisions were warranted because attachment(s) need to relate to the mandatory and enforceable portions of the standard, such as being referenced in the requirement language. Moving the content to IG was most appropriate, since IG provides a means for industry to develop examples or approaches to illustrate how registered entities could implement a standard. This revision also conforms with the 2019 revisions to Standard Processes Manual, Section 2.5, which removed Application Guidelines, or guidelines to support the implementation of the associated Reliability Standard, as an element of a Reliability Standard.