An Introduction to NERC PRC-027 Studies for Transmission, Synchronous, and Inverter-Based Resources

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Abstract -- **NERC PRC-027 is one in a suite of standards implemented to increase grid reliability in response to the 2003 Northeast United States blackout. The intent of the PRC-027 standard is to maintain coordination of protection systems on the Bulk Electrical System (BES) to minimize the breadth of outages needed to clear faults in order to minimize system impacts and prevent cascading outages. This paper describes the approach and challenges of performing NERC PRC-027 studies for transmission systems, synchronous generation plants and inverter-based resources. The paper will highlight the critical differences between performing a study for each type of system, with an emphasis on producing appropriate documentation for asynchronous generation plants which provide unique coordination challenges. It is intended that this paper will serve as a reference to aid electric utilities and independent power producers in complying with the NERC PRC-027 standard.**

I. Introduction

The intent of the NERC PRC-027 standard is to maintain coordination of protection systems on the Bulk Electrical System (BES) to minimize the breadth of outages needed to clear faults. Limiting outages reduces the impact on the BES, preventing cascading outages. This broad standard applies to owners of transmission systems, generation facilities, and some distribution networks. In later sections of this paper, we will take a closer look at applying PRC-027 to different portions of the BES.

II. The Standard

In simplified terms, NERC PRC-027 outlines three requirements for owners:

- Requirement R1 – Develop a process for producing coordinated protection settings (both new and updated) for BES elements.
- Requirement R2 – Review coordination for BES elements either
  - Option 1 – Every six calendar years or
  - Option 2 – When short circuit currents (single or three phase) change by 15% or more.
- Requirement R3 – Follow the processes established in Requirement R1 anytime new or revised settings are required.

Criteria for coordination of the protection elements themselves is left to the discretion of the owner. The standard does not specify a minimum time interval for considering elements coordinated, nor does it describe contingencies or abnormal switching that should be considered. Industry standards, engineering best practices, and the owner's knowledge of individual systems should be applied when outlining criteria for coordination studies.

Once a baseline coordinated system has been established, coordination must only be revisited when a system topology change introduces new or revised relay settings or on the timeline chosen under Requirement R2. The scope of Requirement R2 is limited to current-sensitive protective elements as the coordination of these elements is susceptible to changes in fault current magnitude. Elements which fall under PRC-027 requirements are:

- *"21 – Distance if:*
  - *Infeed is used in determining reach (phase and ground distance), or*
  - *Zero-sequence mutual coupling is used in determining reach (ground distance).*
- *50 – Instantaneous overcurrent*
- *51 – AC inverse time-overcurrent*
- *67 – AC directional overcurrent if used in a non-communication-aided protection scheme" [1]*

The following sections discuss the standard as it applies to transmission systems, synchronous generation, asynchronous generation, and distribution systems, respectively.

III. Process Documentation

A well-designed process document created to meet Requirement R1 will serve as a road map to guide engineers in maintaining a coordinated system over the long-term. It will also greatly simplify the process of responding to audits. Each BES owner must document how and when they will update their short circuit model, how to integrate new or upgraded protective relay settings, and how to effectively exchange information with neighboring owners so that coordination is maintained across system boundaries.

The plan should contain the following elements:

i. *Applicable Equipment Documentation* – BES elements and their protection systems that are subject to the standard should be identified in the plan. As new equipment comes on-line, or old equipment is retired this list shall be revised.
   - *Depending on the size of system, an owner may develop a single plan that encompasses all their BES elements, or an owner with a large system may choose to develop a process document for each site or subsystem*.

ii. *Applicable Protection Relay Elements* – Protection systems for the BES elements documented in the plan should be reviewed to determine if they have current sensitive protection elements. Each element found should be identified in the plan. As protection systems are modified, the list should be adjusted to maintain compliance.
   - Some owners may consider developing template calculation workbooks for overcurrent and distance elements that document fault currents and clearing times and demonstrate coordination with neighboring elements. These blank templates can be attached as appendices to the process document and serve to keep coordination checking and records retention consistent over time.

iii. *BES Neighbors* – The plan should identify neighboring BES equipment owners who shall be provided updated coordination data whenever changes are made to the local system that could affect protection system coordination and who data will be requested from every six calendar years when a compliance check is performed. Care should be taken to coordinate updates to short circuit model details including network topology and equipment data.

iv. *Coordination Study Guidelines*– Include a brief discussion on the coordination study to be performed. Cover topics such as the boundaries of the study and the timeline option selected for continued compliance with Requirement R2.

v. *New Equipment Guidelines* – The plan should document how changes will be accounted for any time additions, removals, or adjustments are made to the local system's protection to maintain coordinated systems even if the six-year time limit of Requirement R2 is not up.

vi. *Documentation Retentions* – The plan should describe how the results of the previous steps will be documented for compliance with the standard, including retention of any calculation workbooks developed and baseline short circuit studies if Requirement R2, Option 2 has been selected.

   Well formatted and documented results will make future compliance checks quicker than the initial effort.

IV. Transmission Systems

A baseline PRC-027 compliance study for transmission owners entails a wide-area coordination study. Equipment protected by elements requiring coordination to comply includes:

- Bus(s)
- Main Power Transformer(s)
- Transmission Line(s)

Most transmission and sub-transmission lines are protected by a communication-aided distance or current differential scheme as their primary protection, with step-distance and often overcurrent elements as backup. These backup elements should be properly coordinated regardless of the presence of a communication-aided primary scheme. Standard differential bus protection will not be included in the coordination evaluation, but any systems employing inverse-time-overcurrent protection of buses will need to have the bus protection included.

In addition to maintaining coordinated backup elements, it is advisable to study N-1 contingencies when evaluating large transmission systems by removing a single transmission line or transformer from service. History shows us that major blackouts are usually a series of unfortunate events that one would not think likely to happen in conjunction [3]. While not explicitly required by PRC-027, planning for the loss of communication-aided tripping schemes as well as an additional equipment outage is a good practice for improving BES resiliency. The final decision on the number and type of contingencies to be considered is left to the owner's discretion.

An accurate Thevenin equivalent(s) of the interconnected systems must be obtained to determine relay operate times. Additionally, coordination of protective elements at points of interconnection between transmission owners must be evaluated. This requires cooperative communication between owners, as is required by the standard.

Significant changes to the transmission owner's system or interconnected systems are likely to cause an appreciable change to overcurrent coordination. In those cases, a coordination study should be performed to establish a new baseline. Barring significant topology changes once a coordinated system has been established and documented, maintaining compliance through the options laid out in Requirement R2 requires significantly less effort than the initial evaluation. If a new system component, such as a transmission line, is added to a system but overall fault currents do not change more than the 15% threshold defined by the standard, the new line protection relays can be coordinated to their immediate neighbor relays and compliance will be met without establishing a new short circuit baseline. Maintaining accurate models and documentation of settings and past compliance studies will only make revisiting coordination more efficient.

Selecting which option for meeting Requirement R2 will be followed may come down to the size of an owner's system. For owners of vast systems covering many transmission and subtransmission voltages, it may be easiest from a planning and tracking standpoint to use Option 1. Break a system into six or more parts and recoordinate a set portion of system(s) every year. By the time each section has been completed, it will be time to start again on the first. This option may be simpler than checking fault currents across the entire system and keeping track of where a deviation of 15% or more has occurred, requiring a coordination study and new short circuit baseline. For smaller systems, however, Option 2 is likely the avenue requiring the least effort.

V. Synchronous Generation

Equipment protected by elements requiring coordination to comply with PRC-027 at synchronous generation plants typically includes:

- Generator(s)
- Step-up Transformer(s)
- Bus(s)
- Unit Auxiliary Transformer(s)
- Transmission Line(s)

Synchronous generators employ current differential as primary protection, which is not subject to the requirements of PRC-027. Phase distance elements reaching into the transmission system to provide backup system and step-up transformer protection are common as well as voltage-restrained or voltage-controlled phase time-overcurrent elements.

Most synchronous generation plants employ one or more step-up transformers, with the generator connected to a medium voltage (4.16-18 kV) winding and coupled to the transmission system through a high voltage (69-500 kV) winding. Differential protection of these transformers is not subject to the requirements of PRC-027, however, any phase and/or ground overcurrent backup elements are.

Typical bus differential protection will not be included in the coordination evaluation, but any basic overcurrent employed as bus protection will need to be evaluated.

The unit auxiliary transformer(s) at synchronous generating plants are responsible for powering critical supporting systems required to keep a synchronous generator on-line. These critical systems include inlet air heaters in cold climates, lubrication pumps, turning gears, cooling systems, and excitation systems. These transformers are protected by a wide range of protective devices including fuses, low voltage circuit breakers, single function relays, and multifunction relays. Time-overcurrent protection is often the primary method of protection, requiring inclusion in the PRC-027 analysis.

Synchronous generation plants include one or more transmission lines to carry the power generated out into the BES. These lines typically have primary and backup protective relays located at the generation plant. Coordination of these relays with the relays at the remote end(s) of the transmission line(s) typically represents the boundary of coordination for PRC-027 requirements for a synchronous generation plant. Primary protection for these lines will typically be a scheme based on distance protection which is subject to the requirements of PRC-027, or a line current differential scheme which is not subject to the requirements of PRC-027. Backup protection for these lines will often be step-distance relay(s) which are subject to the requirements of PRC-027 or redundant line differential relays which are not subject to the requirements of PRC-027. These line relays may also employ ground time-overcurrent elements, which are sensitive to changes in fault current magnitudes and should be analyzed.

Utilizing R2, Option 2 to maintain compliance with the standard after an initial coordination study has been completed may be the best fit. The operate time of protective elements located at synchronous generation sites are not going to vary much due changes to the interconnected utilities' system (barring introduction of infeed within a generator relay distance element reach). The source of fault current behind these elements is the generation itself; only significant generator upgrades and generator additions or removals will change fault currents seen by synchronous plant protective elements significantly over time.

An accurate Thevenin equivalent of the connected utility in addition to generator manufacturer data must be obtained to model fault data and relay operate times. If the interconnecting utility will provide relay setpoints, coordination can be fully checked by the synchronous generation owner. This data is often not available, and the synchronous generation owner must provide their relay settings at the POI to the utility for confirmation of coordination. The synchronous generation owner must maintain a process document and confirmation of coordination per R1 and R3.

VI. Asynchronous Generation

Equipment protected by elements requiring coordination to comply with PRC-027 at asynchronous generation plants typically includes:

- Generators
- Inverters
- Unit Step-up Transformer(s)
- Collector Feeders
- Collector Station Bus(s)
- Collector Station Step-up Transformer(s)
- Transmission Line(s)

Asynchronous generation utilizes low voltage breakers with trip units that are limited to instantaneous and time-overcurrent protection elements, or even fuses, to protect the inverter and generator equipment.

Step-up transformers are installed to convert from the low voltage asynchronous generation sources to medium voltage collector system voltages. The protection for these unit step-up transformers is either a fuse, combination of fuses, or a breaker and relay. Regardless of the equipment chosen for these step-up transformers, the protection is limited to a time-overcurrent approach which is subject to compliance with the standard.

Asynchronous generation plants cover a relatively large geographic area and make use of medium voltage collector feeders to aggregate the generator output. Protection of these feeders is accomplished with medium voltage circuit breakers and multi-function relays. Generally, time-overcurrent and instantaneous overcurrent elements are the only protection elements enabled in these relays that are subject to compliance with PRC-027.

Bus work in asynchronous generation plant collector systems will often be protected by bus differential protection which is not load sensitive and thus is not subject to the requirements of the standard.

Collector station step-up transformers step the voltage up from medium voltage distribution levels to high voltage transmission and are the tie-in to the BES. They are usually protected primarily by differential and sudden pressure relays which are not subject PRC-027. Back up relaying is provided by instantaneous and time-overcurrent relays which are subject to compliance with the standard.

Asynchronous generation plants will have one or more transmission lines to carry the power generated into the BES. These lines typically have primary and backup protection relays located at the generation plant. Coordination of these relays with the relays at the remote end(s) of the transmission line(s) represents the boundary of coordination for PRC-027 requirements for an asynchronous generation plant owner who is not also the transmission owner. Primary protection for these lines may be a distance protection scheme, which is subject to the requirements of PRC-027, or a line current differential scheme, which is not subject to these requirements. Backup protection for these lines will typically be redundant distance relay(s), which are subject to the requirements of PRC-027, or redundant line differential relays, which are not subject to these requirements. These lines often also employ ground time-overcurrent relays which are sensitive to changes in fault current magnitude and should be analyzed.

Coordination of asynchronous generation plants is usually driven by requirements set by the generator manufacturer. They will provide required or recommended pickup and trip times based on generator capability and withstand characteristics. The unit step-up transformers also have relatively rigid pickup and trip time requirements based on their own withstand and damage characteristics. The plant coordination will be established by first considering those relatively rigid requirements and then integrating more typical coordination elements including the collector system cables or conductor damage curves, collector station transformer withstand and damage curves, and transmission conductor damage curves.

Changes to the interconnected transmission system or the collector station step-up transformer represent the most likely changes to require a re-evaluation of coordination. The collector system and asynchronous generators will rarely see significant changes. As such, R2, Option 2 is the easiest option for maintaining compliance with the standard after an initial coordination study has been completed.

An accurate Thevenin equivalent of the connected utility, as well as proper modeling of the fault contribution of the asynchronous generation, must be obtained to record accurate relay operate times. If the interconnecting utility will provide remote terminal relay setpoints, coordination can be fully checked by the asynchronous generation owner. This data is often not available, and the asynchronous generation owner must provide their relay settings at the POI to the utility for confirmation of coordination. The asynchronous generation owner must still maintain a process document and confirmation of coordination.

VII. Distribution

The standard does require compliance from Distribution owners in some limited cases but those will not be covered in this paper. Traditional load serving distribution systems are not subject PRC-027 compliance.

VIII. Standard Implementation Schedule

FERC order 847 was issued June 07, 2018 which provided final approval of the standard. Per the PRC-027 standard implementation plan and NERC deferral due to the COVID-19 pandemic, compliance with the standard is currently required by April 01, 2021.

IX. Data Acquisition

Obtaining current system data often presents the most difficult and time-consuming task encountered during a PRC-027 evaluation. This is particularly true when studying renewable energy sites which are often developed and then sold, in some cases, multiple times. Data is regularly difficult to obtain for older synchronous generation sites. It isn’t referenced often since these facilities may not change for long periods of time. Many of them still feature electromechanical relays that less experienced personnel may have trouble gathering settings from. Obtaining protection relay settings can be time consuming but is achievable. Consideration for the time required to obtain all the necessary data for a PRC-027 evaluation should not be overlooked when considering a schedule to achieve compliance.

Most facilities which are required to show PRC-027 compliance should have existing and current PRC-023 or PRC-025 studies which can be used to expedite the data gathering and relay element evaluation process for PRC-027. Arc flash studies are often good sources of data as well.

Obtaining Thevenin equivalent system impedances or available fault currents at the intertie(s) between renewable plants and other BES owners, from one or more third parties is often a difficult and time-consuming task. Requirement 1 and Requirement 3 of the PRC-027 standard aim to alleviate data gathering difficulties BES owners may experience during implementation of the standard by requiring electrically joined facilities to share information.

X. Conclusion

PRC-027 is not the longest or most complicated PRC standard, however its requirements cover significant portions of BES protection systems regardless of the type of facility being considered. Achieving compliance can seem daunting. Fortunately, the coordination effort(s) that PRC-027 requires should have been done already, at least once. What the standard aims to do is prevent a "set it and forget it" mentality as well as facilitate better "BES neighbors" by formalizing the requirement to share information between BES owners.

Owners preparing for compliance should focus on data collection and developing a plan that will be effective for both initial and future implementation. Pay attention to how the plan will accommodate un-planned or short-notice emergency replacements by operations and maintenance groups since many of those changes could create a need to update coordination. Addressing retention of the data associated with these changes in the plan will aid future coordination efforts. Failure to retain data from these types of replacements is a significant source of out-of-date information.

For BES equipment, some form of coordination study has been done at some time, at least prior to the original interconnection with the BES. Often the study documentation hasn't been updated in years or has been lost over time. Performing a new wide area coordination study and implementing a PRC-027 compliance plan at the same time is logical. The paper "Lessons Learned Implementing a Wide-Area Coordination Program in Preparation for NERC PRC-027" is a useful reference describing this approach [4].

While the start-up effort for compliance may be high, due diligence developing the plan will make compliance over time simple and bring a level of consistency to your protection system that may have been lacking before.

XI. References

[1] NERC, *PRC-027 Coordination of Protection Systems for Performance During Faults,* National Electric Reliability Council, Draft 6, 2015

[2] IEEE, *Std. 242-2001: IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems*, The Institute of Electrical and Electronics Engineers, New York, 1999, ISBN 0-471-85392-5.

[3] R. G. Farmer and E. H. Allen, "Power System Dynamic Performance Advancement from History of North American Blackouts," 2006 IEEE PES Power Systems Conference and Exposition, Atlanta, GA, 2006, pp. 293-300.

[4] C. Byrne, D. Bucco, C. Sanden, C. Short, A. Torres, E. Wong, "Lessons Learned Implementing Wide-Area Coordination Program in Preparation for NERC PRC-027", 2016 Western Protective Relay Conference, Spokane, WA

XII. Biographies

Caitlin Short joined the SCADA and Analytical Services group at POWER Engineers in 2013. She specializes primarily in system protection and coordination studies but also has experience in power system analysis, transmission line design, and arc flash studies. Caitlin received her B.S. in electrical engineering from the University of Idaho and is a registered professional engineer in the states of Idaho and New Mexico.

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Tony Limon joined POWER Engineers in 2015. He is a member of the SCADA and Analytical Services group where he performs a variety of electrical system studies for transmission, generation, and distribution projects. He has a background in power system analysis, protective relaying, arc flash studies, protection and control testing and commissioning and project management. Tony holds a B.S. in electrical engineering from Washington State University. Tony is a licensed professional engineer in the states of Washington and Texas.