Commission Testing Methods for Protection Systems

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Abstract

Commission testing should be designed to assure that the protection system is set and wired to operate correctly for the specific site application. This is especially important with modern micro-processor relays because of the large number of available protection and control elements and configurable logic. Commission testing also establishes a baseline of data to be used to support maintenance testing of all the protection system components of NERC PRC-005. This paper examines how and why the objective of commission testing is different from maintenance testing. Through real examples, the authors highlight the use of system study data and design documents during commission testing to verify proper protection system operation including all enabled protection elements and configured logic. Best practices for commissioning of each NERC PRC-005 protection system component and examples of real world issues found during commissioning are discussed as well as the importance of records keeping relative to PRC-005.

1: Introduction

Protection systems require testing to assure proper operation. This testing can be divided into 3 separate stages over the life of the protection system. The first stage is type testing where the user tests the system in a laboratory environment to convince themselves that the system will perform as expected for their applications and to approve its use in their power system. Once the system has been type tested and approved for use, the user performs commission testing on the installed systems to assure that the protection system is set and wired to operate safely and correctly for the specific site application. This is especially important with modern micro-processor relays because of the large number of available protection and control elements and configurable logic. Lastly, the user performs on-going life-cycle maintenance testing of the system.

Commission testing is critical to assuring a safe and functionally operating system in both utility and industrial locations. For utility installations, commission testing also establishes a baseline of data to be used to support the continuing maintenance testing of all the protection system components of NERC PRC-005. While not mandatory for industrial and many utility systems, the processes and methods identified in PRC-005 and valuable for maintenance of those systems. This paper examines how and why the objective of commission testing is different from maintenance testing. Real examples are used to highlight the use of system study data and design documents during commission testing to verify proper protection system operation including all enabled protection elements and configured logic. Best practices for commissioning of each NERC PRC-005 protection system component and examples of real world issues found during commissioning are discussed as well as the importance of records keeping relative to PRC-005.

2: Goals and objectives of protection system commission testing

Fundamentally, commission tests are preformed to assure that the protection system is performing correctly as required for the unique application. NERC, in the reliability standard PRC-005-2 ("Protection System Maintenance") [ref 1] defines 5 components of a protection system:

- Voltage and current sensing devices
- Protection system DC supply (including batteries, chargers, monitoring circuitry, and power supplies/inverters whether they include batteries or not)
- Control circuitry (including wiring, trip coils, electro-mechanical auxiliary relays and lock-outs, etc.)
- Communication systems required for protection system operation
- Protective relays

Commission testing is required to assure that the protection system is functioning within specifications and that the application is appropriate for the site and application.

2.1: Voltage and Current Sensing Devices

Most voltage and current sensing devices are magnetic core instrument transformers. However, non-magnetic core devices such as optical VTs and CTs and Rogowski coils are a growing portion of the installed base. Typically, these non-magnetic core devices have self-testing functionality and the only testing that can be done on them are primary injection and in-service load checks (refer to Energizing procedures and in service load checks section). Commission testing of magnetic core VTs should include a ground leakage test to assure there are no unintentional grounds in the windings, a turns ration check (TTR) and a polarity check. Any test voltage applied to a VT must be applied to the primary winding to avoid the presence unsafe high voltages. Commission testing of magnetic core CTs should include a ground leakage test to assure there are no unintentional grounds in the windings, a turns ration check (TTR), a polarity check and an excitation check. The methods and tools used for testing and the results of the tests should be saved as base-line data for future tests.

2.2: Protection system DC supply

Commission testing of the protection system DC supply (including batteries, chargers, monitoring circuitry, and power supplies/inverters whether they include batteries or not) should be performed based on the technology used. A variety of tests for commissioning battery banks exist including battery load/capacity tests, cell impedance measurement, inter-cell connection resistance measurement, specific gravity measurement and cell voltage checks. These tests will verify the battery bank meets design specifications and industry standards. Battery charger testing includes function testing and verification of battery charger settings and alarms as part of the checkout. The methods and tools used for testing and the results of the tests should be saved as base-line data for future maintenance tests.

2.3: Control circuitry

The AC and DC wiring should be checked physically and electrically. Point to point wire checks assure that the wiring is physically in agreement with the design documents. Injection of electrical quantities assures that the wiring performs the necessary functions and helps to identify any errors in the design. A system must be developed to document each test. One method is to highlight the wiring on the design documents as the circuits are tested using a different color highlighter pen for physical and electrical tests. Before powering up the DC supply wiring the load fuses should be pulled and an ohm meter used to verify there are no short circuits. Reinstall load fuses one circuit at a time and verify that no DC grounds are acquired.

Primary or secondary injection can verify the AC wiring is correct. In either case, the goal is to perform the injection without lifting wires and the objective is to confirm that the signals get to where they are needed without mixing up the phases or polarities. For CT secondary injection, 3-phase test currents from a test set are injected into CT circuits by clipping directly onto the CT wires as close to the CT as possible (directly on the CT secondary terminals if accessible, otherwise on the CT shorting block terminals). Note that since the test set driving voltage is low, virtually none of the injected current goes into the CT. To easily identify the phases at a glance, it is common practice to inject varying magnitudes of current on the three phases (for example: 0.5, 1.0 and 1.5 amps into phases A, B and C respectively) and then use the receiving relays' metering functions to verify. For VT secondary injection, it is necessary to isolate the VT winding from the secondary wiring before applying a test voltage to the secondary wiring. This is best done by pulling the VT secondary fuses and clipping the test set to the load side of the open fuse block. Applying a varying magnitude of test voltage to the VT secondary wiring can cause some unexpected metering results in the receiving relays, especially if the VT is open delta connected. For wye connected VTs, phase-neutral voltages should be injected and verified with the relays' metering. For open delta connected VTs, phase-phase voltages should be injected and verified with the relays' metering. Each device that receives the VT signal should be checked to assure that the entire VT circuit is wired correctly.

Primary injection is not as common as secondary injection. A 3-phase generator (typically LV) is used to energize the substation bus and then loads are placed on each circuit to cause current flow. The various relays' metering is then checked to assure that the signals are being received correctly. This test requires a thorough understanding of the referencing that each relay uses to define the phasor angles. This referencing is often subject to or controlled by relay settings and care must be taken when interpreting the metered values to assure that the phases are correctly identified.

The DC control wiring should be electrically tested while function testing the relay to assure that each circuit performs the intended functions. (refer to protective relay section).

2.4: Communication systems

During commission testing, all communication systems need to be verified. This includes communication systems used by the protection system for protection (pilot channels, transfer trip, etc.) and communication systems used for operation and control (SCADA, voice, LANs, protection system data remote access, etc.) – note that the communication systems used for operation and control are typically not subject to PRC-005 requirements but must be tested. In any case, point to point communications need to be functionally verified and documented for future reference, including signal levels and data transfer rates. SCADA remote control functions need to be functionally tested to verified that they perform as expected. SCADA metering functions which originate from standalone metering devices (transducers, meters, etc.) should be tested using current and voltage injection into the metering devices. SCADA metering functions which originate within the relay (digital values read from relay memory registers) will be tested as a part of the relay functional tests (refer to protective relay section). The end to end functionality of stand-alone communication devices used for transfer trip and/or pilot wire (power line carrier, audio or digital tone systems, etc.) should be verified and documented prior to protective relay functional tests. The end to end functionality of digital relay communications used for transfer trip and/or pilot wire will be tested as a part of the relay functional tests (refer to protective relay section).

2.5: Protective relays

Commission testing of protective relays includes relay acceptance testing, loading and verifying settings, system tests performed on the protection system or panel and in-service load checks. Depending on owner preferences, the relay can be acceptance tested to verify that 100% of all included analog and digital I/O operate correctly even if not all the I/O are used.

For digital relays, setting files need to be loaded into the relays, typically using vendor specific software tools. Once the settings have been loaded into the relay the vendor software should be used to run a comparison between the setting file and the actual settings contained in the relay. If the settings were loaded correctly there should be no differences between the file and the relay's settings. If any differences are found, resend the settings or manually correct the errors and then re-compare. Save an image of the compare report showing no differences for future reference. For non-digital relays, the settings need to be entered and verified through current and/or voltage injection per manufacturer's recommendations.

The protective relay is the central brain of the protection system. Each enabled feature in the relay (protection elements, metered values, logic, communications and I/O) needs to be verified as a complete system to demonstrate that it functions as designed. Many owners are using automated testing programs for maintenance. Automated testing program inject current and voltage based on the settings entered in the relay so they will not be able to detect setting errors like typos. Also, they typically do not test programmed logic or specific I/O functions. While these programs provide excellent and consistent documentation, they should not be used for commission testing other than at the very end to establish a base-line testing report for future maintenance. To assure that any setting typos are discovered, tests of protection functions using current and voltage injection should be based on system study data that supports the intended purpose, not based on the settings entered in the relay. System short circuit software should be used to provide current and voltage test values for line protection (ex: test values for close-in reverse fault, close-in forward fault, mid-line or balance point fault and remote end fault). Running these tests with the pilot communication system operational will also prove the end-end functionality of the pilot system. Transformer protection test values should be derived based on the transformer winding connections as discussed in "Methods for Testing Transformer Differential Relays Applied to Delta-Grounded Wye Transformers Using Single-Phase Test Currents" [ref 2]. Programmed logic should be functionally tested by injecting current and voltage to operate protection functions used in the logic, operating inputs to the relay that are used in the logic and verifying outputs that are operated by the logic. A logic diagram is recommended for systems that employee complex logic to assure that all the logic is functioned. The logic drawing is also useful as a record of the testing by high lighting the logic as it is tested similar to wire checking documentation. When testing the outputs, verify that the DC circuitry performs as designed all the way to the end device, including any auxiliary relays, lock-out relays, trip coils, etc.

2.6: Energizing procedures and in service load checks

Energizing and loading the primary protected equipment is the last step in commission testing. The details of energizing procedures vary widely from owner to owner but all share a common goal of energizing the equipment in a logical and safe manner. In any case, the primary equipment should not be energized unless the associated protection systems are commissioned and in service. Once the equipment is energized, voltage readings should be taken from all voltage measuring devices and compared to assure that the secondary levels are appropriate and that the phase identification is consistent. This can be challenging on a totally new power system such as a new substation as obtaining references from existing facilities may be difficult. If the protection system includes GPS time synchronization, then an end-end communication signal such as a transfer trip can be used to temporarily trigger waveform capture reports in relays at the new substation and in the existing system (remote substation). The waveforms can then be compared to assure that the phase identification is consistent from old to new. Phasor measurement unit (PMU) data can also be used in GPS clock synchronized systems to compare the angles of local and remote voltages. In addition, cellular based phase checking systems are available which allow you to compare the phase angle of a remote voltage with the phase angle of a local voltage. Care must be taken to remove any temporary settings in relays after the test is complete.

Once the primary equipment is energized, load can be applied through it and the outputs of the current measuring devices can be examined to assure that the ratios, phasing and expected phase shifts are correct. For current based differential elements, the differential and restraint quantities should be examined under loaded conditions to assure that the differential quantity is near or equal to zero and that the restraint quantity is significant. Note that this test requires a significant amount of load to produce reliable results. For high impedance bus differential, only the operating quantity can be examined (voltage across the resistor or the current through the resistor) but the current from each CT should be measured using a clamp-on meter to verify CT ratios. The load check data, as measured, should be recorded for future comparison.

3.0: Maintenance Testing

The data recorded during commission testing will form a baseline for the life-cycle maintenance testing of the protection system. Perhaps the most critical aspect of commission testing as it pertains to NERC PRC-005-2 is that the date of the commissioning records define time zero when using a time-based maintenance method. Insulation and mechanical failures of current and voltage measuring devices can be observed during maintenance by comparing original TTR, ground leakage and excitation testing data with current testing data. Battery and charger performance degradation can be observed over time by comparing original commissioning readings with current readings. Drops in received signal levels can flag communication channel degradation. The as-left relay settings from commissioning become the base-line for maintenance and any changes observed over time must be researched and validated.

4.0: Re-commissioning

Any time a significant piece of the protection system is replaced the aspects of the protection system associated with that piece of equipment should be re-commissioned. If a stand-alone piece of communication hardware is replaced, then the commission tests associated with that piece of equipment (level checks, functional end-end checks, I/O checks, etc.) need to be re-tested. If a VT is replaced, the VT tests (TTR, ground leakage, etc.) need to be re-tested and in-service load checks repeated. Any time a change is made to the control wiring all the wiring that could have reasonably been disturbed (intentionally or unintentionally) must be re-tested, even if the wiring after the change is the same as it was before the change (ex.: wires lifted and then re-landed in the same place). If a digital relay is replaced in-kind with a new relay of the same order code and firmware and the as-left settings from the old relay are loaded into the new relay without conversion or modification, only the relay hardware (analog and digital I/O, digital communication, settings comparison after loading, etc.) and any disturbed control wiring need to be re-tested.

If a change is made to the relay settings, then the relay's commissioning tests of current and voltage injection and logic verification should be re-tested for areas of the settings associated with the change. The entire relay's commissioning tests of current and voltage injection and logic verification should be re-tested if the firmware in the relay is changed such that the as-left settings from the previous firmware version need to be converted to load them into the relay. If the as-left settings from the previous firmware version can be loaded directly into the relay without after a firmware upgrade conversion, then the only test required is the comparison to verify that the settings were loaded correctly.

5.0: Case Studies

5.1: Protection problems at mining operation result in need to re-commission switchgear

Two new cubicles were added to an existing line-up of medium voltage switchgear at a large mining operation. The existing line-up had been in-service for many years; however, no commissioning records could be located for the existing line-up. One of the new cubicles serves as a stand-by generator tie and the other serves a new pumping load center located remotely. The new cubicles were installed and settings were entered into the new relays based on a coordination study done be the Engineer. With no further testing, the new cubicles were energized and load was applied through the new pump breaker. In the process of trying to start-up the new generator several problems in the CT and VT wiring caused the generator to trip every time load was applied. The new generator relay was a modern digital relay so the waveform and event data were examined to determine what was wrong. In the process, several questions were asked about the settings which resulted in significant setting changes. The CT and VT wiring errors and the setting problems would have been discovered before energization had a correct commissioning process been done.

Similar questions were asked about the new load cubicle. There were several output contacts wired to the new relay which did not have any logical programming in the settings. Only the trip output was correctly programmed and it was not verified prior to energization. The new pump load cubicle relay and wiring was designed to be identical to the existing cubicles so the technician looked at the output settings for the existing relays and was surprised to find that only the trip outputs were programmed. Since no commissioning records could be located for the existing line-up, the logical conclusion was that it had never been properly commissioned either. As a result, plans are being made to take an outage of the entire line-up and re-commission it to assure a safe and functional operation.

5.2: Modelling error discovered when settings did not perform as expected

An old electro-mechanical 115 kV transmission line protection panel was being replaced with a modern digital relay panel. Short circuit calculation software was used to provide phase and ground distance element test values at for 3LG, LL and 1LG local bus faults (reverse), close-in line faults, mid-line faults and remote bus faults. The zone 1 distance elements were set to reach 85% of the line, the zone 2 were set to reach 125% of the line and the zone 3 (reverse) were set to reach 200% of the remote end zone 2 over-reach. The phase distance elements performed as expected for the 3LG and LL faults (Zone 1 operated for close-in and mid-line faults, the zone 2 operated for close-in, mid-line and remote end faults and the zone 3 operated for local bus fault). However, when the 1LG faults were run the ground distance zone 1 operated for the remote bus fault which should have been beyond its balance point. By applying a little math, it could be seen that the test values provided by the short circuit program for the remote bus fault were indeed within the zone 1 reach (the relay was operating correctly). After a bit of investigation, it was discovered that the line zero sequence impedance entered in the short circuit program's data base was wrong. This affected the Z0/Z1 ratio entered into the relay setting, causing the ground distance elements to over-reach. The modelling error was corrected and a new Zo/Z1 setting entered. New test points were issued for all the 1LG faults and the relay performed as expected. In this case, if test values had been based on the relay settings with the wrong Z0/Z1 setting, the elements would have tested correctly and the error would not have been discovered. By using test values from the short circuit program during commission testing, a possible future mis-operation was avoided and the modelling error was corrected.

5.3: Setting errors discovered while commissioning replacement generator protective relay

An old outdated generation 1 digital protection relay on a gas turbine generator was to be replaced with a modern digital relay. Only the relay was replaced, not the panel so the existing wiring was reused to a significant extent. After installing and wiring the relay, the technician put the new settings into the relay and ran an automated testing program which returned a report showing no errors. Next the technician and field engineer manually tested each enabled element in the relay by injecting current and voltage and verifying that the element and associated logic and I/O operated as designed. The automated testing program essentially injected the same currents and voltages but did not test the logic and I/O. In the process, it was observed that an output was wired to trip the field breaker but that output was not enabled in the logic. The logic was modified and re-tested to confirm correct operation.

The technician and engineer also noticed that there was a ground fault lock-out on the panel that was never operated during the tests. In fact, the old electro-mechanical over-voltage relay used for bus ground fault detection had been removed as a part of this project. The 3V0 voltage signal from the bus VT was wired into the new relay but no elements, logic or output contact had been set in the new relay to provide the required protection. Apparently, the engineer that designed the new settings based them only on the settings that were in the old relay, missing the functional addition of the ground protection. The wiring was modified to provide an output to operate the ground lock-out, the settings were modified to provide the necessary protection and logic, and tests were run to verify the proper operation.

In this case, 2 significant errors were discovered in the settings during commission testing even though the automated testing program issued a report saying everything was OK.

5.4: Verification of relaying functions in relay using simulated faults.

An existing outdated transmission line panel required replacement. A standard line relay package using the same manufacture and model of relays as used on other line panels was selected to provide conformity in the protection for prints, settings and commissioning. As part of the check and commissioning of the new protection, fault records were developed and applied to the protective relaying. The fault records are used to simulate real world faults and to determine if the protective relaying will operate as designed. The application of various fault records was used to verify relay reaches, directionality of relay elements, and relay logic by viewing sequence of event records (SER). The functionality of associated breakers, lockouts and relay communications were tested as a part of the fault record applications to the protective relaying system.

In applying various types faults to the protected relays, the relay did not trip for a three-phase fault. In previous applications of the same manufacturer and model of relay on other lines, the relay operated for three-phase faults. From investigation of the waveform files and the SER it was determined that the loss of potential (LOP) was being declared during the three-phase faults and was blocking the trip. The function testing found under certain system condition, the relay design would not operate for certain three phase faults. It was discovered that on this particular weak in-feed system the LOP function would operate incorrectly for close-in three-phase faults. This issue has yet to be resolved by the owner or the manufacturer.

Testing with simulated faults and/or operating conditions demonstrated to the relay engineer the design of the protective relaying, provided an understanding of how the protective relay's firmware operates and brought attention to a relay firmware design issue.

6.0: Conclusions

Protection systems require testing to assure proper operation. This testing includes type testing, commission testing and on-going life-cycle maintenance testing. Each type of test is important but proper commission testing is critical to assuring a safe and functionally operating system in both utility and industrial locations. For utility installations, commission testing also establishes a baseline of data to be used to support the continuing maintenance testing of all the protection system components of NERC PRC-005. While not mandatory for industrial and many utility systems, the processes and methods identified in PRC-005 are still valuable to those systems. The methods and objectives of commission testing are different from maintenance testing. Commission testing is designed to assure that the entire system functions as required for the specific application. Maintenance testing is designed to assure that the system continues to operate as commissioned. Commission tests should be based on the desired outcomes, not on the settings and wiring provided. Real examples are used to highlight the use of system study data and design documents during commission testing to verify proper protection system operation including all enabled protection elements and configured logic. Best practices for commissioning of each NERC PRC-005 protection system component and examples of real world issues found during commissioning were identified as well as the importance of records keeping relative to PRC-005.

7.0: References

1: Standard PRC-005-2(i) — "Protection System Maintenance", North American Electric Reliability Corporation, approved by FERC May 29, 2015.

2: "Methods for Testing Transformer Differential Relays Applied to Delta-Grounded Wye Transformers Using Single-Phase Test Currents", by Tom Ernst and Craig Talbot, Minnesota Power Systems Conference, November 11, 2015.

8.0: Biographies

Ken Sletten: Ken Sletten is a Principal Protection and Maintenance Engineer for Minnesota Power. He has been with Minnesota Power for 30 years in protection application, testing and troubleshooting. Prior to Minnesota Power, Ken worked at Montana Dakota Utilities in various engineering roles. He has received a Bachelor of Science in Electrical Engineering from North Dakota State University. He is a registered Professional Engineer in the States of Minnesota and Wisconsin.

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