The New NERC Protection System Maintenance Standard

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1 Introduction

The NERC Protection System Maintenance and Testing Standard Drafting Team has, in recent months, issued its draft of Reliability Standard PRC-005-2, *Protection System Maintenance*, along with supporting explanatory documents. The new Standard implements FERC-ordered changes by adding specific requirements for maximum maintenance time intervals and activities. However, the new draft Standard also opens doors to optional, future-oriented maintenance approaches based on condition or performance monitoring that can extend intervals and reduce or eliminate hands-on testing of some components. In any case, PRC-005-2 will, after industry comment and adjustment, become mandatory and enforceable with fines for noncompliance.

PRC-005-2 is one of the most technically complex reliability standards to come from NERC to date. It is critical for protection engineers, utility management, and other system protection asset owners to understand both the minimum requirements to meet, and the opportunities to transform the organizational approach to protection system maintenance.

In Sections 2 through 4, we explain the organizational and legal process through which this Standard has evolved. In the remainder, we explore the technical content and ramifications of the Standard provisions. Understanding the latter is critical for planning a compliance strategy. Most organizations will need some lead time to understand the need, develop the strategy, and deploy the systems and designs for effective compliance.

2 FERC Order 693 and NERC Action

Since the mid-1990's, NERC has maintained a number of reliability standards, including several focused on maintenance of different categories of Protection Systems. Then, in 2005, the US Congress passed the Energy Policy Act of 2005, which, among other things, required the Federal Energy Regulatory Commission (FERC) to establish a national (US) Electric Reliability Organization (ERO), and further established that FERC should approve mandatory standards for electric system reliability. Subsequent to the Energy Policy Act of 2005, the National Electric Reliability Council (now the North American Electric Reliability Corporation, or NERC) applied to FERC to be the US ERO, and also re-wrote the prior reliability standards into what became referred to as the "Version 0 Standards". FERC subsequently named NERC as the ERO, whereupon NERC filed the "Version 0" Standards with FERC, requesting that FERC declare those standards to be mandatory and enforceable under the Energy Policy Act of 2005. The various Canadian provinces have similarly named NERC as their Electric Reliability Organization, and have varying methods of determining that NERC Standards are mandatory and enforceable; three provinces (Alberta, British Columbia, and Manitoba) automatically adopt NERC Standards as mandatory and enforceable upon NERC Board of Trustees approval (Alberta includes a 10-day public review period for objections). The remainder of this discussion will focus on the statutory enforceability as it applies to the United States.

In February 2007, FERC issued the initial order on reliability standards, Order 693, approving many of the Version 0 standards as mandatory and enforceable. Among those standards were:

- PRC-005-0 – Transmission and Generation Protection System Maintenance and Testing
- PRC-008-0 – Underfrequency Load Shedding Equipment Maintenance
- PRC-011-0 – Undervoltage Load Shedding Equipment Maintenance and Testing
- PRC-017-0 – Special Protection System Maintenance and Testing

In Order 693, FERC also ordered NERC to "develop a modification to" PRC-005-0, PRC–008–0, PRC-011-0, and PRC-017-0 "through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System". FERC also directed NERC to consider combining these four standards into a single standard.

While NERC is the Electric Reliability Organization for the United States, FERC exercises oversight, reviews and approves the standards, and has the statutory responsibility to direct NERC to modify the standards to conform to FERC's position on each respective standard. Therefore, when FERC offers directives, in an order, to NERC regarding changes to filed standards, NERC is obligated to address those directives.

2.1 Combining Four Current Standards

The previous section listed the four currently approved NERC Standards addressing maintenance of protective relays and related equipment

PRC-005-0 – *Transmission and Generation Protection System Maintenance and Testing* addresses the protection systems that are generally intended to protect from faults. PRC-008-0 – Underfrequency Load Shedding Equipment Maintenance specifically addresses a separate set of protective relays and associated equipment that are applied for underfrequency load shedding, to trip loads for generation deficiencies and maintain acceptable system frequency. For those who have applied undervoltage load shedding to trip loads for widespread voltage instability, PRC-011-0 – Undervoltage Load Shedding Equipment Maintenance and Testing addresses this particular group of equipment. Finally, for application of Special Protection Systems (also known as Remedial Action Schemes) which take various system actions based on system conditions or contingencies, PRC-017-0 – Special Protection System Maintenance and Testing requires maintenance of the related equipment.

Of these, PRC-005 is the most wide-reaching, but, in practice, there is a great deal of commonality among these standards. All of these applications involve protective relays, control circuits, and current and/or voltage transformers. Most of them involve station batteries, and many involve communications circuits. FERC's directive to consider combining these standards thus seems logical.

The existing four standards are very general - they simply say that an entity must have a program, that they must implement it, and that they document the implementation of the program. In addition, PRC-005-0 requires that the entity have a basis for whatever intervals they are using. The lack of specificity in the existing standards has led to many questions; for example,

- What constitutes a basis?
- What Generation Protection Systems are included?
- What constitutes evidence and documentation?

Additionally, according to NERC, PRC-005-0 is by far the most violated of all of the mandatory reliability standards. This may be caused partly by the complexity of Protection System Maintenance and the vast quantity of activities involved, but NERC has also cited lack of clarity in the standard as a major factor. In addition, many entities reportedly have not included all required classes of equipment in their program, and have not established a basis for the intervals that they are using.

The draft PRC-005-2 is endeavoring to address not only the FERC directives, but also many of the issues that have caused the existing standard to be frequently violated. The draft standard, first of all, establishes a more specific definition of what equipment needs to be included in a protection system maintenance program. It also better defines which protection systems within a generation plant are included. Further, it establishes minimum maintenance intervals for time-based programs, relieving the utility of the duty to establish a basis for intervals, and establishes minimum maintenance activities. For those who wish to employ technology to minimize maintenance, the draft PRC-005-2 establishes the ability to utilize monitoring of the protection system components to lengthen the intervals. For those who wish to analyze maintenance program results to determine basis for various activities, it further establishes requirements related to performance-based maintenance. All of these are explained at length below.

3 NERC Standard Development Process

NERC has a carefully-defined process for developing standards. The process will be summarized here, together with comments on how the process is implemented for PRC-005-2.

1) Any party may submit a Standards Authorization Request, or SAR. A SAR must describe the purpose of the proposed standard (or revised standard), why the standard (or revision) is needed, and provide a brief description of the proposed standard. In the case of PRC-005-2, the NERC System Protection and Control Task Force (SPCTF) introduced the SAR.

2) The NERC Standards Committee considers the SAR and decides whether to move the proposed project forward. If the project moves forward, the SAR is posted for a 30-day public comment period, and the Standards Committee forms a SAR Drafting Team to address comments. The SAR for this project was posted from June 11, 2007 to July 10, 2007, and the NERC SPCTF was named as the SAR drafting team.

3) After the public posting period, the SAR drafting team addresses the comments, makes any related changes to the SAR, and returns it to the Standards Committee for approval. After approval, the Standards Committee requests nominations for a Standard Drafting Team via the NERC email lists and via posting on the NERC web site. Nominations for the PRC-005-2 Standards Drafting Team were sought from July 15, 2007 to July 29, 2007.

4) The Standards Committee then names a Standard Drafting Team from the nominated individuals and drafting of the Standard begins. The Standard Drafting Team for PRC-005-2 first met on November 28-29, 2007, and has met a total of twelve times. All NERC meetings are posted on the NERC website, and are open to all interested participants; registration is required for planning purposes, but there is no registration charge.

5) When the Standard Drafting Team feels that the draft standard is ready for public comment, the Standard Committee posts the standard. Each standard must be posted for public comment a minimum of twice, for a minimum of 30-days, and at least one of these postings must be for a 45-day comment period. Anyone may submit comments. PRC-005-2 was posted for its first 45-day comment period from July 24, 2009 to September 8, 2009.

6) After each comment period, the Standard Drafting Team must address all submitted comments. If substantive changes are made to the standard, the standard must be again posted for a comment period. The PRC-005-2 Standard Drafting Team is now in the process of addressing comments from the first comment posting.

7) If the Standard Drafting Team feels that the Standard is ready for balloting, they request that the Standards Committee post the standard for a 30-day pre-ballot period, which would be followed by a 15-day ballot period. Balloting is open only to members of the NERC Registered Ballot Body, and a Standard must achieve both a 75% quorum and a 67% approval to pass.

8) If, on the first ballot, there is even a single negative vote, the Standards Drafting Team must address all comments and, if necessary, make changes to the standard. The standard is then posted for a recirculation ballot.

9) Following approval of the standard via the balloting process, the Standards Committee submits the Standard to the NERC Board of Trustees for their approval.

10) After approval of the NERC Board of Trustees, NERC then files the Standard with FERC for their approval. After study, FERC will issue a Notice-of-Proposed Rulemaking and seek comment on their proposed rule. After consideration of comments, FERC will then issue an Order relating to the standard. If the Order approves the standard, the standard will be officially considered approved 60-days after the Order is entered in the United States Federal Register.

The Standards Drafting Team for PRC-005-2 is comprised of 18 industry professionals, all of whom are experienced in protection system maintenance and who must work in their own organizations and jobs to achieve compliance once the new Standard becomes mandatory and enforceable. The development has focused on meeting FERC order requirements while injecting industry experience, and also on opening doors to new technical opportunities with today's protection system components and enterprise data processing systems. They are listed at the end of the paper.

The draft PRC-005-2 has just completed the first comment posting, and comments are being addressed. The Standards Drafting Team anticipates several additional comment postings through 2010 before the standard will be ready to ballot.

4 Applicability

4.1 Included Components of the Protection System

NERC provides a defined term, "Protection System", for use in all of the related standards, including PRC-005. By referring to this defined term within the associated standards, each standard applies to all equipment addressed in the term.

The term is currently defined as, "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry." Some elements of the term seem fairly clear, but there have been questions about whether "station batteries" includes the battery charger, and about which communications systems are included.

The PRC-005-2 Standard Drafting Team has modified the definition of "Protection System" to "Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing inputs to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices."

PRC-005-2 addresses all of the elements within the defined Protection System, with specific maintenance intervals and activities. The relationship between these elements, as they apply to a typical HV Transmission Line, is shown in Figure 1.

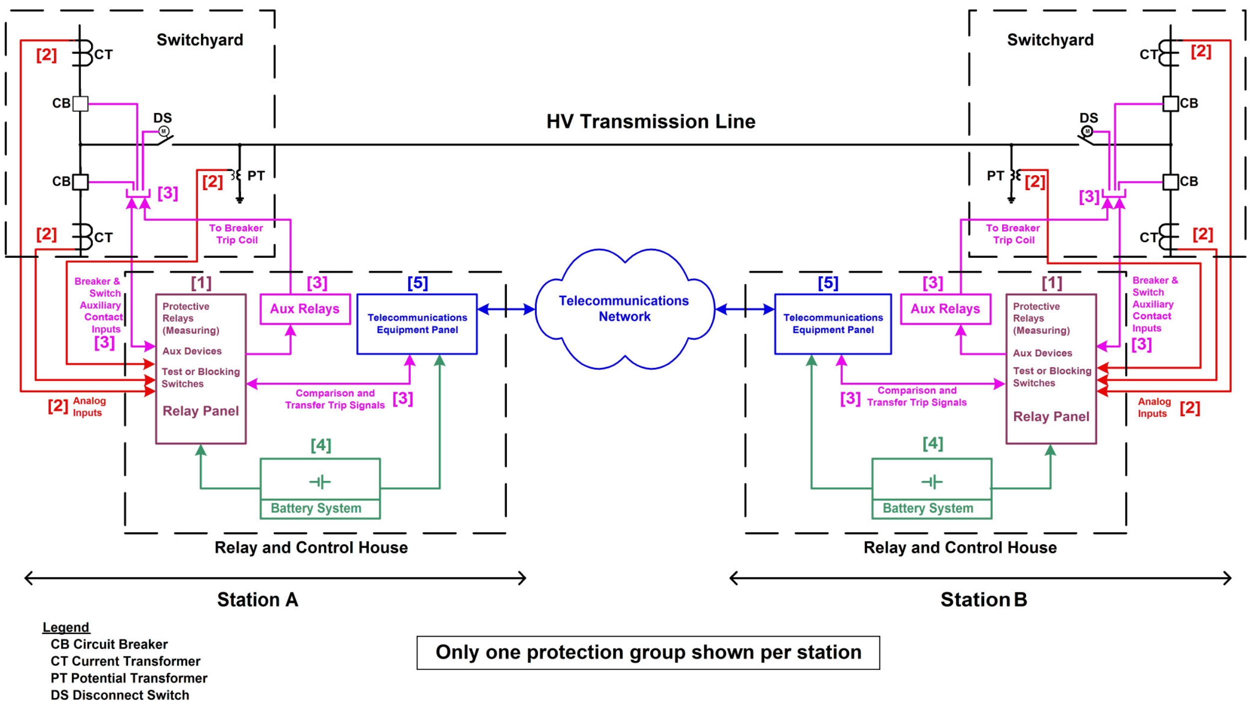

Figure 1 - Transmission Line Protection System Showing Components in NERC Definition

4.2 Which Electric System Facilities Are Covered?

NERC Standards, according to the Energy Policy Act of 2005, apply to what is generally referred to as the "Bulk Electric System". NERC provides this definition: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." As noted in the NERC definition, the eight NERC regions are allowed to further define the Bulk Electric System, and all have chosen to do so to some degree. PRC-005-2 is generally applicable to Protection Systems for Bulk Electric System facilities in any given region. Responsibility for compliance falls to owners of these facilities.

In addition, PRC-005-2 applies to any entity which owns underfrequency load-shedding facilities that are installed to meet regional underfrequency load shedding requirements, to any entity which owns either an undervoltage load shedding system or a Special Protection System that is addressed by the related NERC standards. The entities responsible are no different from those currently responsible for the aggregated four legacy standards.

To provide additional guidance to generator owners, PRC-005-2 specifies that it applies to the following generation plant-related protection functions:

- Protection system components that act to trip the generator either directly or via generator lockout or auxiliary tripping relays.
- Protection systems for generator step-up transformers for generators that are part of the BES.
- Protection systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).
- Protection systems for generator-connected station service transformers for generators that are part of the BES.
- Protection systems for system-connected station service transformers for generators that are part of the BES.

5 Technical Background - Varieties of Testing

To understand the focus of the Protection System Maintenance Standard, consider what is to be accomplished in a *maintenance* test, as compared to all other types of testing activities that a technician could perform on a protective relay or the surrounding systems that support its operation:

1) <u>Development tests</u> – testing by the manufacturer or application engineer to determine if the function of the system meets the functional design specification that started the development. For example, a relay manufacturer may apply tens of thousands of fault cases to a new product in a model power system or real time digital simulator (RTDS©) laboratory to see if it correctly responds to signals that look like in-service internal and external faults. The goal is to find and remove design errors, such as algorithm response problems, program bugs, or signal processing hardware errors, before the new model design is released for production and sale.

2) <u>Type tests</u> – documented testing of a presumably-completed design by the manufacturer and/or an independent laboratory. The goal is to demonstrate that the product conforms to industry standards and will perform its specified functions reliably in service. The tests may include:

a) Physical environment tests - temperature and humidity, vibration and shock, conducted electrical surge and interference withstand capability, radiated radio frequency emissions and susceptibility, accelerated life test.

b) Functional tests – for example, standard industry overcurrent inverse time curves, or conformance to specified services of a standard data communications protocol like DNP3 or IEC 61850.

3) User laboratory evaluation tests – a utility user brings a sample product of interest into a laboratory to perform informal tests of performance, usability, or adaptability. The goal is to functionally qualify the product for use on the utility system, prior to purchase decision. Some users may perform their own versions of the type tests, even including physical environment tests.

4) Factory Acceptance Test (FAT) – A purchased system of equipment that was specifically ordered for a utility application or company standard design is tested on the manufacturer's production floor, usually with customer witnesses. The goal is to demonstrate that the equipment as built conforms to the order specification before it is shipped to the customer site. FAT testing is usually functional and is aimed at finding errors in system design, wiring, or construction.

5) Site Acceptance Test (SAT) or Commissioning Test – After installation, the system of equipment is functionally tested to show it performs all the functions required for service. The goal is to uncover any installation errors, or problems of interaction between the installed system and the power apparatus it controls. A new commissioning test may be required after a major repair or modification of an existing installation.

Following the Commissioning Test, the equipment is placed in service, and modern users also begin tracking the reliability, performance, or failure history using an asset management data base.

6) **Maintenance Test** – Equipment in service is periodically tested to verify its functioning. *The goal is to determine that there have been no failures or components, damage to the installation, or unobserved changes in configuration that could cause the system not to function as required.* In particular, it is not necessary to reverify the performance of a part that doesn't change or fail on its own. For example, the Zone 2 phase distance relay on an electromechanical panel can fail or drift and needs periodic testing. However, in a multifunctional microprocessor relay, it is only necessary to determine once that the relay is measuring its ac inputs properly, that its internal processing electronics are running, that it is able to close its trip contact, and that it is set as intended. Once these are known, there is no further benefit in checking all the distance zone boundary points to make sure they are all where they should be. They will be in the intended places - they can't move around in this type of relay. If the relay was not applied correctly or settings were incorrectly calculated, no amount of extra maintenance testing will show the problem – the problem needs to be fixed in the application and setting development process.

Periodic maintenance testing is performed to ensure that the protection and control system is operating correctly after a period of time of field installation. These tests may be used to ensure that individual components are still operating within acceptable performance parameters - this type of test is needed for components susceptible to degraded or changing characteristics due to aging and wear. Full system performance tests may be used to confirm that the total protection system functions from measurement of power system values, to properly identifying fault characteristics, to the operation of the interrupting device and associated interlocking with automatic or manual restoration devices and schemes.

The most important observation about the maintenance test is that it does not need to repeat what was shown in laboratory or commissioning tests. The design doesn't change in service by itself. We are only looking for failures and human-induced unknown changes. What might fail or change depends on the equipment generation – electromechanical relays can exhibit drift or failure of any piece of a large system, and there is no way to find this but to test the performance of each of those pieces. By contrast, newer microprocessor based products tend to work as designed and set, observably alive and stable, until there is a clear failure that is easy to spot.

We talk about a maintenance *test*, but in many cases an invasive test by a human technician is neither required nor a good idea. In following sections of this paper we explain other ways of finding the problems the test is looking for, and the new NERC standard tells users how utilities can avoid unneeded testing if they want to. We generalize the idea of a maintenance *test* to that of maintenance *verification* – knowing *by any means* that there are no failures or problems that the maintenance test was aimed at finding.

5.1 Time Based Maintenance (TBM)

Testing of performance on a periodic time schedule, as the industry has done since its inception with electromechanical and analog solid state relays, is described today as Time Based Maintenance (TBM). Externally prescribed maximum maintenance or testing intervals are applied for components or groups of components. The intervals may have been developed from prior experience or manufacturers' recommendations. The TBM verification interval is based on a variety of factors, including experience of the particular asset owner, collective experiences of several asset owners who are members of a country or regional council, etc. The maintenance intervals are fixed, and may range from months to years.

TBM can include review of recent power system events near the particular protective relaying terminal. Operating records may prove that some portion of the protection system has operated correctly since last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock is reset for those components.

We introduce two newer variations on TBM:

5.2 Condition Based Maintenance (CBM)

CBM is a program based on equipment whose integrity and performance can be observed while the equipment is in service - it is actually monitoring or testing itself as it performs its protection job. Continuously or frequently reported results from non-disruptive self monitoring of components demonstrate operational status - we are achieving maintenance verification that is as good as or better than that of TBM testing. The testing program does not disturb the self-monitoring part of the system, until it reports a failure.

Whatever is verified by CBM does not require manual testing, but taking advantage of this requires precise technical focus on exactly what parts are included as part of the self diagnostics. Most of the internal components of a modern microprocessor relay are monitored. Self-monitoring capabilities may include the ac signal inputs, analog measuring circuits, processors and memory for measurement, protection, and data communications, trip circuit monitoring, and protection or data communications signals. For those conditions, failure of a self-monitoring routine generates an alarm and may inhibit operation to avoid false trips. Certain internal components such as critical output relay drivers and contacts are not equipped with self-monitoring, so they must be periodically tested. The method of testing may be local or remote, or through observing correct performance of the component during a system event.

5.3 Performance Based Maintenance (PBM)

PBM is a maintenance program whose maintenance intervals are established based on analysis of historical results of TBM failure rates on a statistically significant population of similar components. If this group of components has shown very low failure rate in tests, the maintenance interval is extended as much as possible while keeping an acceptably low failure rate. Even after documented low failure rate experience has been used to justify extended time intervals, some infrequent TBM must be maintained to justify continued use of extended intervals, and to discover any increase in failure rates of the population requiring a more intensive program.

5.4 Relationship of Maintenance Types

The TBM is the overarching maintenance process of which the other types are subsets. Unlike TBM, PBM intervals are adjusted based on good or bad experiences. The CBM verification intervals can be hours or even milliseconds between non-disruptive self monitoring checks within or around components as they remain in service.

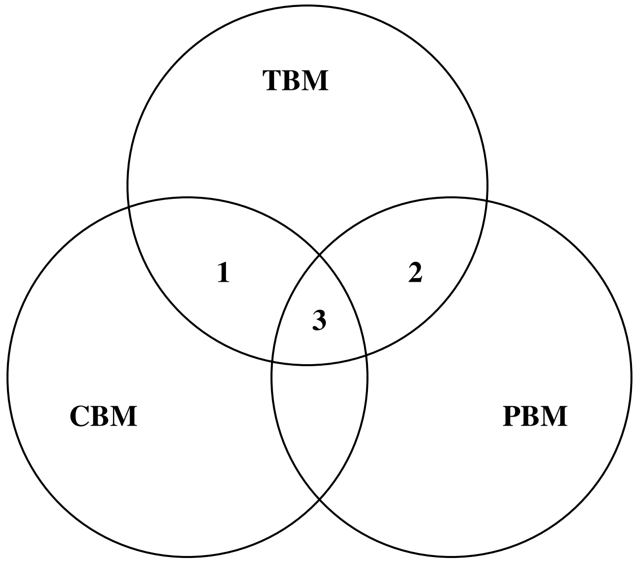

Figure 2 Relationship of time based maintenance types

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System. Figure 2 illustrates the relationship between various types of maintenance practices described in this section. In the Venn diagram, the overlapping regions show the relationship of TBM with PBM historical information and the inherent continuous monitoring offered through CBM.

This figure shows:

- Region 1: The TBM intervals that are increased based on known reported operational condition of individual components that are monitoring themselves.
- Region 2: The TBM intervals that are adjusted up or down based on results of analysis of maintenance history of statistically significant population of similar products that have been subject to TBM.
- Region 3: Optimal TBM intervals based on regions 1 and 2.

5.5 Verifying the Protection System in Sections

If we are to claim without question that our maintenance program is effective, we have to verify that the whole protection system is working – every device and path that is important to protection. No path is left unverified – either it is monitored, or it must be periodically tested.

An efficient test sequence checks each unmonitored part or path only once in each testing interval. For example, the trip path to a circuit breaker operated by many relays needs to be tested by tripping the breaker, but only one test trip is required. Before letting one of the relays actually trip the breaker, First, open a test switch in the trip path and test all the relays but one, including their trip paths up to the switch, using a temporarily wired auxiliary relay. Then, close the test switch and let the last relay trip the breaker for the trip test.

One commonly-used verification approach is to test the entire protection scheme as a single unit, from voltage and current sources to breaker tripping. Such an end-to-end test may require a lot of equipment and personnel at diverse locations, as well as an outage of all the tested facilities at once. For practical ongoing verification, the protection system can be divided into segments or portions which may be tested or monitored individually. The boundaries of the verified sections must *overlap* to insure that there are no gaps in the verification.

To be technically valid, a maintenance program should be supported by documentation showing how the verified protection system segments overlap so that no segment is left unverified.

Figure 2 shows an example of how the overlapping of monitoring and tests might be accomplished in a carrier blocking pilot line protection system based on microprocessor line relays. It shows the use of monitoring, but also demonstrates monitoring gaps that must be covered either by periodic testing, or by observation of a correct natural operation within the testing time interval.

All of TBM testing, TBM via observation, CBM, and PBM extension of testing time may be combined by a protection system owner to achieve an efficient hybrid maintenance program. For example, a protection system may be divided into four or more overlapping sections with a different maintenance methodology for each segment:

- Time based maintenance with appropriate maximum testing intervals as required in the Standard to be described below.
- Opportunistic verification of parts subject to TBM using analysis of fault records.
- Very substantial extension of intervals for parts showing low failure rates, if the owner has a large enough population, and has concrete TBM documentation to show statistically low failure rates.
- Partial condition based monitoring of some parts that greatly extends the maintenance intervals for those parts.
- Full condition based monitoring of certain eligible parts, so that these parts never need a periodic test.

The next section reviews specific requirements for each of these elements in the new draft NERC Protection System Maintenance Standard.

A fundamental concept underlying the program is that, while human testing may be needed to prove protection is working, human error is a documented cause of failures and misoperations. Keeping human hands off of equipment is a vastly superior approach if there are other ways to verify that equipment is functioning.

5.6 Example of Verifying or Testing in Overlapping Zones

Figure 3(a) shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal of maintenance testing is to verify the ability of the entire two-terminal pilot protection scheme to protect the line for internal faults and to show the system can avoid overtripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

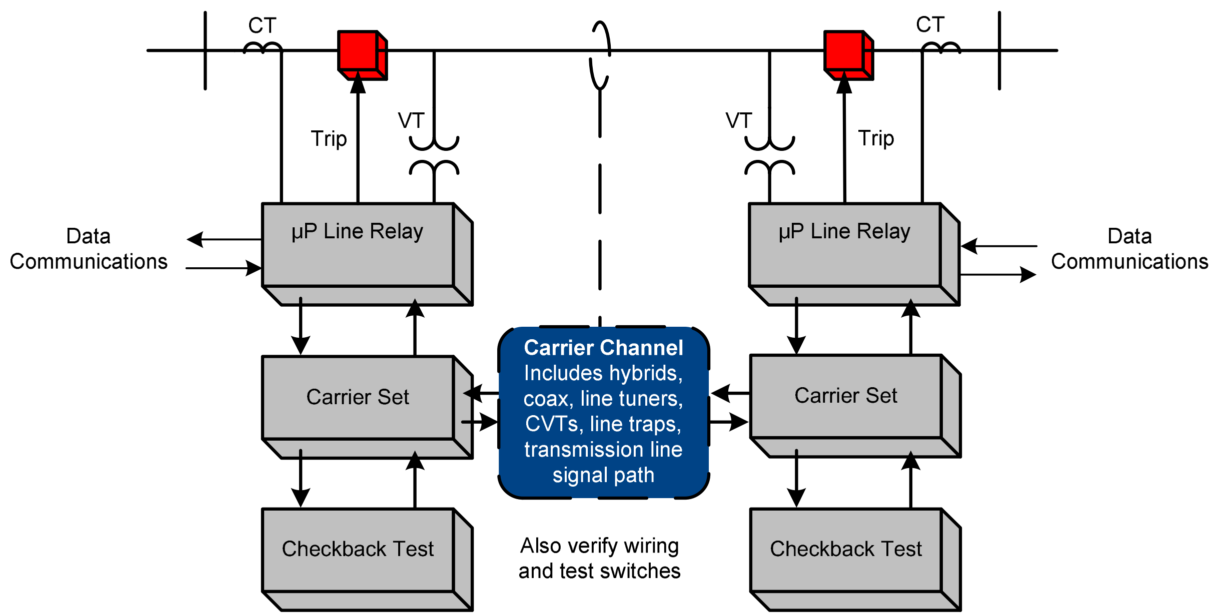

Figure 3(a) – Example line protection application

In this example, verification takes advantage of the self-monitoring features of microprocessor multifunction line relays at each end of the line. For each of the line relays themselves, the example assumes that the user has the following arrangements in place:

1) Each relay has a data communications port that can be accessed from remote locations, so operators or maintenance personnel can check ac current and voltage readings, and can see any alarm conditions the relay reports.

2) The relay has internal self-monitoring functions that report failures of internal electronics via communications messages or via SCADA.

3) The relays report loss of dc power, and the relays themselves or external monitors report the integrity of the dc battery supply.

4) The CT and PT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. These metered values are reported by data communications through a substation data concentrator to the control center. For maintenance, the user elects to compare these readings to those from a redundant set of line protection relays not shown in the Figure, or to other readings in the station. Comparison with other such readings to within required relaying accuracy verifies instrument transformers, wiring, and analog signal input processing of the relays. One effective way to do this is to utilize the relay metered values directly in SCADA – they can be cross-checked and alarmed in the data concentrator, or checked at the control center where they can be compared with other references or with state estimator values.

5) Breaker status indication from auxiliary contacts is verified in the same way as in (4). Status indications must be consistent with the flow or absence of current.

6) Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay trip coil monitor (TCM) and reported via communications.

7) Correct operation of the on-off carrier channel is also critical to security of the protection system, so each carrier set has a connected or integrated automatic checkback test unit. The automatic checkback test runs several times a day. Newer carrier sets with integrated checkback testing check for received signal level and report abnormal channel attenuation or noise, even if the problem is not severe enough to completely disable the channel.

Monitoring activities 1 through 6 plus the checkback test 7 comprise automatic verification of all the protection system elements that experience tells us are the most prone to fail. But, is this complete verification?

The large dotted boxes of Figure 3(b) show the portions of the line protection system that are verified by monitoring, as defined by the features just listed. These segments are not completely overlapping, and within portions the shaded boxes show elements that are not verified:

1) TCM verifies the continuity of trip coils and trip circuits, but this does not assure that the circuit breaker can actually trip if the trip coil should be energized.

2) Within each line relay, all the microprocessors that participate in the trip decision have been verified by internal monitoring. However, the trip circuit is actually energized by the contacts of a small telephone-type “ice cube” relay within the line protective relay. The microprocessor energizes the coil of this ice cube relay through its output data port and a transistor driver circuit. Today’s relays have no way to monitor the output port, driver circuit, ice cube relay, or contacts of that relay. These components whose state is unknown are critical for tripping the circuit breaker for a fault.

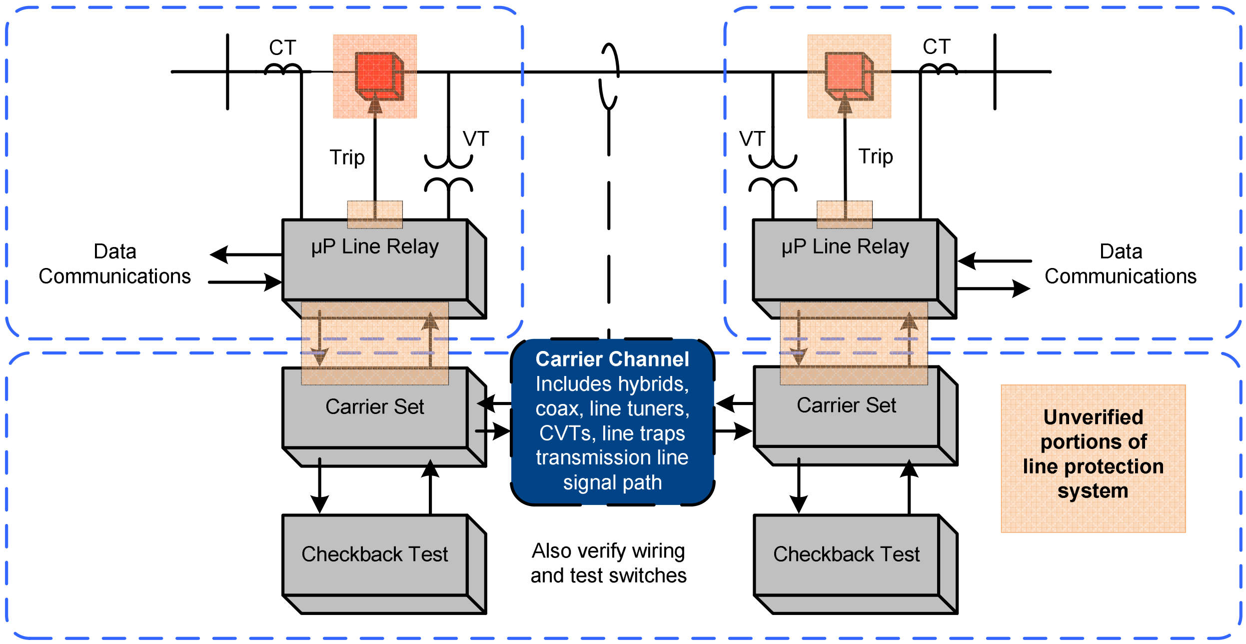

Figure 3(b) – Monitoring gaps in example line protection application

3) The checkback test of the carrier channel does not verify the connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state. These connections include microprocessor I/O ports, electronic driver circuits, wiring, and sometimes telephone-type auxiliary relays.

4) The correct states of breaker and disconnect switch auxiliary contacts are monitored, but this does not confirm that the state change indication is correct when the breaker or switch opens.

A practical solution for (1) and (2) is to periodically initiate actual breaker tripping through the protective relay output at a convenient time, from the relay front panel, or from substation HMI or from SCADA via data communications. This test can be conducted without a substation visit.

Also, clearing of a naturally-occurring fault shows that the breaker was tripping, and thus might reset the time interval clock for testing of the breaker. However, if the breaker has dual trip coils and both redundant relay systems called for the trip, we cannot conclude that breaker tripping was fully tested. In this situation, there is no way to know if both coils are able to trip – we only know that at least one worked. A manually initiated trip command through each of the two trip coils separately does comprise a valid test of the breaker.

Testing of the relay-carrier set interface in (3) requires that each relay key its transmitter, and that the other relay demonstrate reception of that blocking carrier. This can be observed from relay or DFR records during naturally occurring faults, or by a manual test.

Note that if the checkback test sequence were programmed in the relay user logic instead of being in the carrier set, the checkback test would pass from relay logic processor at one end all the way through the channel to the corresponding processor at the other end. This includes the relay-to-carrier wired connections at both ends. The monitoring gap is completely eliminated. This shows an example of how relay and relay system design can evolve to improve monitoring and thus reduce human maintenance work, once the industry has come to understand the principles of technically complete monitoring.

5.7 Completeness of Monitoring in Relays and other IEDs

How much do we really know about status of all the protection critical parts of a self-monitoring microprocessor relay? While manufacturers have done an excellent job of monitoring active electronics within the relay, we explained how some elements are not monitored. In some cases, the user can't know what might have been missed; there are some parts that the relay designer could have overlooked.

As will emerge in the next section, the newly developed NERC standard requires that the monitoring concretely verify any part of the system that the user would like to exclude from TBM. However, the standard also recognizes the monitoring capabilities and benefits of today's relays, even without a map of the relay circuits and programs showing exact coverage. The standard thus defines two tiers of monitoring:

5.7.1 Relays with partial monitoring

These include internal self diagnosis and alarm capability, which must assert for power supply failures. They must have input voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming. The alarms are automatically provided daily (or more frequently, perhaps continuously) to a location where action can be taken for alarmed failures.

Most current or recent generation microprocessor relays meet this definition with no further investigation by the manufacturer or user. If the protection system design qualifies, the user can greatly extend most testing intervals, and has a shorter list of testing activities than is the case for electromechanical or analog solid state protection systems. The Standard gives much more detail on the exact definitions for other parts of the NERC Protection System and the increases in maintenance time intervals for each.

5.7.2 Relays with full monitoring

In addition to the meeting the definition for relays with partial monitoring, the relay A/D converters are continuously monitored and alarmed. More generally, every function required for correct operation of the relay must be continuously monitored and verified, and detected maintenance-correctable issues are reported. Fully monitored protection system components also include verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance-correctable issue alarms must be reported within 1 hour or less. As with partial monitoring, the Standard gives additional requirements for other components of the protection system besides the relays themselves.

In general, some internal portions of a relay sold today can qualify, but not every part. The manufacturer will need to provide users with a map of what parts of the product comply, as well as application connections that are be required for compliant monitoring of those parts.

The huge benefit of meeting this requirement is that any fully monitored part of the relay or the protection system *does not require periodic testing*. This gives relay and IED vendors a great incentive to develop and document designs with greater completeness of monitoring. This reduces maintenance cost and human error issues for the user, and gives the relay vendor a marketplace advantage. The user will need to collect and document the design compliance with the Standard requirements – it is not adequate to just take the vendor's marketing claims as a basis for performing no testing in service.

6 Overview of the Standard Contents and Supporting Documents

A copy of the draft NERC PRC-005-2 on Protection System Maintenance is supplied along with the present paper. It begins with new definitions, followed by an introduction which explains which utility assets are covered and who is responsible for compliance. These were explained in Section 2 above. Section B of the Standard spells out the requirements for selecting and designing a Protection System Maintenance Program (PSMP) based on a user-selected combination of TBM, CBM, and PBM. For TBM and CBM, it points to the central and lengthy activity Tables 1(a), 1(b), and 1(c) explained next. For PBM, it points to Attachment A at the end, which explains the PBM approach and requirements. Compliance measures and Violation Severity Levels (VSLs) have not yet been determined – these will impact the approach of NERC, WECC, or other RRO auditors who will check for compliance when the Standard is placed into effect, and the consequences to the utility of any deficiencies found in audits. Note in Section D on Compliance that responsible parties are required to retain records of designs and of compliance activities such as testing records, and to present them on demand of an auditor. This requires serious planning as we explain below.

6.1 Table 1(a) – Level 1 Unmonitored Protection System Maintenance

This table characterizes the pure Time Based Maintenance (TBM) program.

For some users, the new PRC-005-2 will be easier to implement than today's mandatory and enforceable but non-specific PRC-005-1. The existing PRC-005-1 requires that the protection system owner have a maintenance program, *that the owner document a basis for that program*, and that the owner keeps records that it is carrying out its program. Documenting a basis can be vague assignment and a tough task. We explained above that in calling for a revision of PRC-005-1, FERC specified that NERC develop specific maintenance time intervals and activities for various types of Protection System equipment, and this is provided in Table 1(a) of PRC-005-2. This eliminates the need to state a basis – a protection owner can choose a strict TBM program based on the stated activities and time intervals in this table.

We repeat here only a sample of the four pages of this table to explain the format. See the supplied draft PRC-005-2 for the full tables.

The Table 1(a) heading describes the general category of unmonitored protection systems or components. In the Standard, no monitoring is referred to *Level 1 monitoring*. A user that wishes to continue with TBM can use these times and activities, even if there is some monitoring.

The Type of Component column lists the elements according to the definition of the NERC Protection System given earlier in the paper. Note that, since PRC-005-2 absorbs the old standards for testing of UFLS, UVLS, and SPSs, these now appear as additional elements. Specifically, categories on subsequent pages of table 1(a) include more requirements for flooded cell lead acid batteries, valve regulated batteries, Nickel-Cadmium batteries, battery charging systems, non-battery dc supply technologies, communications systems for relaying, UFLS and UVLS relays in distributed or centralized schemes, and SPS.

Excerpt from draft NERC PRC-005-2 Table 1a - Level 1 Monitoring **Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems** **General Description:** Protection System components which do not have self-monitoring alarms, or if self-monitoring alarms are available, the alarms are not transmitted to a location where action can be taken for alarmed failures.		
Type of Component	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	6 Calendar Years	Test and calibrate the relays (other than microprocessor relays) with simulated electrical inputs. (Note 1) Verify proper functioning of the relay trip outputs. For microprocessor relays verify proper functioning of the A/D converters (Note 2) Verify that settings are as specified.
Voltage and Current Sensing Devices Inputs to Protective Relays	12 Calendar Years	Verify proper functioning of the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays
Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS)	3 Months	Verify the continuity of the breaker trip circuit including trip coil (except for protection system control circuitry associated with breakers that remain open for the entire "maintenance interval" period").
Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS)	6 Calendar Years	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System.
Protection system communications equipment and channels.	3 Months	Verify that the Protection System communications monitoring and alarms reflect the intended communications system condition by means of a substation inspection.
Station dc supply (that has as a component any type of battery)	3 Months	Verify proper electrolyte level (excluding valve-regulated lead acid batteries). Verify proper voltage of the station battery. Verify that no dc supply grounds are present. **[More dc supply requirements and other requirements in following 3 pages of full Table 1(a) in Standard]**

Notes for all tables:

1. For some Protection System components, adjustment is required to bring measurement accuracy within parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but power system input values must be verified as correct within the Table intervals. The integrity of the digital inputs and outputs will be verified with the Protection System Control Circuitry.

The Maximum Maintenance Interval column lists the time interval specifically for the Maintenance Activities to the right of the time number. For some components like batteries, there are multiple maintenance activities required with different maximum allowed time intervals. There is a table row for each such time-activity group. For the battery example, there is a 3-month requirement to check electrolyte level, voltage, and dc system grounds. A separate 18-month row calls for performance and integrity checks for the battery and its charging system.

Note that these are *absolute maximum allowed times* - even if the user runs into organizational setbacks or natural disasters. Therefore, a practical maintenance program needs to be based on shorter times.

Dc supply systems and their batteries get more space and attention than the other Protection System components in all of the three tables. Batteries are inherently liable to have problems like terminal corrosion, leaking, or internal disintegration or shorting that require at least some level of human oversight, even if some functional monitoring equipment is installed.

6.2 Table 1(b) - Level 2 Partial Monitoring

Again, only a sample of Table 1(b) appears on the following page – see the supplied Standard draft for the full Table. This sample illustrates, however, the impact of increased CBM.

Many microprocessor relays in service today meet the requirements. The alarm path must be monitored, or be tested every 12 years along with the rest of the relay. This is *twice* the maintenance interval allowed for electromechanical or solid state relays that do not meet the definition for partial monitoring. Also, note that the testing activities do not include testing of calibration, as long as there is some way to monitor that ac values are being properly input and read. This can be done by reading the display and comparing to an alternate measurement, or comparing two redundant relay reading sets as described above. Note that this ac value comparison also verifies the instrument transformers and wiring at the same time – a huge simplification of the testing process.

If trip circuits are monitored by the relay or by any other means, the 3-month continuity check requirement of Table 1(a) disappears and it is only required to trip the breaker via each trip coil every 6 years. Note that remote trip circuit monitoring in any form, whether from a microprocessor relay or by any other device that monitors and alarms, relieves the need for the 3 month check shown in Table 1(a).

Any electromechanical auxiliary relay or lockout switch also must be operated for test every six years. The newest relay designs give protection system designers the means to eliminate these auxiliary devices, replacing them with multiple output contacts from the relays themselves (which must still all be tested), or with communications based control like IEC 61850 GOOSE messaging which is inherently self monitoring and which does not require any testing if the monitoring logic is set up to report all inter-relay communications failures.

Excerpt from draft NERC PRC-005-2 Table 1b – Condition-Based Maintenance - Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components **General Description:** Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 2 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	Includes internal self diagnosis and alarm capability, which must assert for power supply failures. Includes input voltage or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming.	12 Calendar Years	Verify the status of relays is normal with no alarms indicated. Verify the proper functioning of the A/D converters within the relay by testing or comparing values against other devices. Verify proper functioning of the relay trip outputs. Verify that settings are as specified. Verify that the relay alarms will be received at the location where action can be taken. See Note 2.
Voltage and Current Sensing Devices - Inputs to Protective Relays	No Level 2 monitoring attributes are defined – use Level 1 Maintenance Activities	12 Calendar Years	Verify the proper functioning of current and voltage circuit inputs from the voltage and current sensing devices to the protective relays
Protection System Control Circuitry (Trip Coils and Auxiliary Relays)	No Level 2 monitoring attributes are defined – use Level 1 Maintenance Activities and intervals	6 Calendar Years	Verify that each breaker trip coil, each auxiliary relay, and each lockout relay is electrically operated within this time interval.
Protection System Control Circuitry (Trip Circuits) (except for UFLS/UVLS)	Monitoring and alarming of continuity of trip coil(s)	12 Calendar Years	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System. Verify that the relay alarms will be received at the location where action can be taken.
Protection system communications equipment and channels.	Monitoring and alarming of protection communications system by mechanisms that check for presence of the communications channel.	12 Calendar Years	Verify that the performance of the channel and the quality of the channel meets performance criteria, such as via measurement of signal level, reflected power, or data error rate. Verify proper functioning of communications equipment outputs. Verify proper functioning of alarm notification. **[Note that 4 more pages of tabulated requirements appear in the full Standard draft]**

Protection communications also shows a dramatic reduction in testing requirements if the presence of the channel between the line terminals is monitored and alarmed. In Table 1(a) the channel must be tested every 3 months. Here in Table 1(b) the existence of monitoring for channel presence extends the interval to 12 years. At the 12-year mark, the maintenance technicians must check the channel for performance and margins. In Table 1(c) described next, we will see that a channel equipment configuration that goes beyond monitoring channel *presence* to monitor *performance*, as described in the activities column of the table, eliminates the need for the 12-year check. If the alarming path is also monitored, such a channel does not require any periodic testing.

6.3 Table 1(c) - Level 3 Full Monitoring

The following page shows an excerpt from Table 1(c). The complete table in the Standard shows how far a Protection System owner can go towards elimination of all manual testing. In the Maintenance Interval column, the term *Continuous* means that monitoring covers the need and no human testing is required.

For a typical line protection terminal, the design can take advantage of any or all of the following:

1) Microprocessor line relay whose manufacturer has documented for the user a listing of all protection-critical components that are monitored, which require testing, and connection or application requirements to support the monitoring. The user has documented the design that completes the monitoring implementation, including monitoring of the alarm path.

2) Instrument transformers, wiring, and relay analog inputs are monitored by comparison of communicated ac measurements from redundant or separately correlated sources, and gaps are alarmed.

3) Protection communications performance parameters are monitored and alarmed. The ability of one relay logic processor to communicate with its remote terminal peers is monitored and alarmed.

4) All tripping and protection-critical signaling or communications paths are monitored for operation or continuity, out through trip coils. Those based on data communications such as IEC 61850 GOOSE messaging are monitored and alarm for loss of messaging on any communications network path among relay processors.

5) Battery systems are comprehensively monitored for voltage, dc grounds, and battery and charger performance as detailed in the full Table 1(c).

Excerpt from draft NERC PRC-005-2 Table 1c – Condition-based Maintenance - Level 3 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems **General Description:** Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance-correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	The relay A/D converters are continuously monitored and alarmed.	Continuous	Continuous verification of the status of the relays. (Note 2) Alarm on change of settings.
Protective Relays with trip contacts	All Level attributes, except relay possesses mechanical output contacts.	12 Calendar Years	Verify proper functioning of the relay trip contacts.
Voltage and Current Sensing Devices Inputs to Protective Relays	Verification of the ac analog values (magnitude and phase angle) measured by the microprocessor relay or comparable device, by comparing against other measurements using other instrument transformers.	Continuous	Continuous verification and comparison of the current and voltage signals from the voltage and current sensing devices of the Protection System.
Protection System Control Circuitry (Trip Coils and Auxiliary Relays)	No Level 3 monitoring attributes are defined – use Level 2 Maintenance Activities and intervals	6 Calendar Years	Each breaker trip coil, each auxiliary relay, and each lockout relay must be electrically operated within this time interval.
Protection System Control Circuitry (Trip Circuits)	Monitoring of the continuity of breaker trip circuits (with alarming for non-continuity), along with the presence of tripping voltage supply all the way from relay terminals (or from inside the relay) through to the trip coil, including any auxiliary contacts essential to proper Protection System operation. If a trip circuit comprises multiple paths, each of the paths must be monitored, including monitoring of the operating coil circuit(s) and the tripping circuits of auxiliary tripping relays and lockout relays.	Continuous	Continuous monitoring of trip voltage and trip path integrity of entire trip circuit is provided with alarming to remote terminal unit upon any failure of the trip path.
Protection system telecommunications equipment and channels.	Evaluating the performance of the channel and its interface to protective relays to determine the quality of the channel and alarming if the channel does not meet performance criteria	Continuous	Continuous verification that the performance and quality of the channel meets performance criteria is provided. Continuous verification of the communications equipment alarm system is provided. **[Note 4 more pages of requirements appear in the full Standard draft]**

If these requirements are met, the only periodic testing requirements that remain are:

1) Trip testing of the circuit breaker through each trip coil alone, every 6 years.

2) Specified inspections and performance tests for the battery-based dc supply system, at 18-month and 6-year intervals.

Such a line protection system design is technically achievable now, and is practically achievable when manufacturers of relays, communications channel equipment, and other components close any monitoring gaps and develop documentation of monitoring that the user can incorporate with his own design documents to show the full monitoring design.

New dc energy storage technologies that do not use batteries and that incorporate monitoring eliminate the activities of (2) just above. Trip testing (1) can be carried out remotely from the substation – for example, through SCADA from the control center – or might be observed from normal fault and control center operations depending on the specific design of the tripping scheme for dual trip coil breakers.

7 Technical References from the Standard Drafting Team

The NERC Project 2007-17 Protection System Maintenance and Test Standard Drafting Team (PSMTSDT) has developed supporting documents to help the industry absorb and implement the details of the new PRC-005-2. These are required reading for managers and engineers who embark on implementation programs. Current Standard development project documents and status are available at http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html.

7.1 Technical Reference and Supplemental Update Document

The NERC System Protection and Control Task Force (SPCTF), now the System Protection and Control Subcommittee (SPCS), published a 2007 Technical Reference on Protection System Maintenance that formed the basis for the drafting team's development of the new Standard. The 2007 Relay Maintenance Technical Reference is available on the NERC web site at http://www.nerc.com/filez/spctf.html under the heading of Standards Technical Reviews.

The PSMTSDT has written a Supplemental Technical Reference which absorbs and updates the original 2007 document to align with the contents of the draft Standard now out for industry evaluation. Find this document at the Project 2007-17 web link just above.

7.2 Frequently Asked Questions (FAQ) Document

The PSMTSDT has also written a lengthy document of *Frequently Asked Questions – Practical Compliance and Implementation,* in which the drafting team members respond to technical and program implementation questions they have anticipated from industry practitioners who use the Standard. The FAQ guidance does not have the force of the Standard. However, it will help engineers, managers, and compliance auditors understand the intent of the Standard requirements, to develop effective and compliant maintenance solutions. Find the link to this document also at the project web page http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html.

8 Taking Advantage of Operating Experience

8.1 Recording Normal Operations

Some natural fault operations or normal operating events can be used to reset TBM maximum interval time clocks, eliminating the need for a separate overt or on-site test. However, note the following requirements:

1) Consider what records you need to have, and how they will be gathered and maintained. For each asset whose testing is documented this way, the owner needs to have a specific hard record (written or electronic) of the event that is used to reset the clock for that asset. Since many utilities do not analyze all operations today, this would call for extra work by the event analysis team. Knowing that the opportunity exists to save field work, some utilities might choose to set up an automatic or semi-automatic program at the control center to log these events, or make it easy for an operator to log them, and associate them with the protection system whose components were verified. This may require development of new applications in the system control and asset management software systems.

2) Be careful about exactly what a particular operation proves, and what remains unproven. Two examples:

   a) We already described the fact that with dual trip coils, and normal operation in which both are energized does not prove that both are working. One utility is addressing this by connecting a communications-based trip path (SCADA or local substation host computer HMI) separately through each of the trip coils. A remote or local manual trip can be performed through each coil to prove its operation.

   b) If an electromechanical Zone 1 distance relay trips correctly for a nearby fault and is observed in a DFR record, its trip circuit might be proven, but its calibration is not proven. Proving calibration this way would require an unlikely sequence of two faults, one just inside the set zone boundary, and the other just outside, with locations that demonstrate correct calibration. This virtually never happens and is not worth the trouble of tracking – the E/M relay will simply need a manual calibration test. However, if the relay is microprocessor based, it is possible for the user to compare its nonfault metered values (displayed or communicated to SCADA) with those of a redundant system or comparable measuring point. This nonfault check proves calibration, and extends the maintenance interval or eliminates other calibration checking.

8.2 Performance Based Maintenance (PBM) Provisions in Standard

Documented TBM may show that some families of similar protective devices are extremely reliable and that it is rare for a maintenance test to show a performance problem or meaningful calibration error. An example is the collection of electromechanical high impedance single phase bus differential relays. It is necessary to consider the populations of each type and manufacturer separately.

With that documentation of TBM, the PBM provisions of draft PRC-005-2 in Attachment A of the supplied Standard draft show the process for determining an extended maintenance interval for such a family of like devices.

First of all, the user needs data for a statistically valid sample of about 60 like products to begin applying an evaluation of extension. Multiple users can aggregate their populations of like devices operating in similar service conditions – for example, a group of generation owners can associate to develop data for a merged population of generator protection relays, where each individual owner does not have a statistically valid sample.

If the TBM results show a problem discovery rate of less than 4%, it is permissible to extend intervals beyond those in Table 1(a) or the other tables that apply to the population of devices. The intervals may be extended up to the point where only 5% of the population is tested every year, if this extension would not cause the testing problem discovery rate to exceed 4%. This is equivalent to a maintenance interval of 20 years! At least this low 5% level of TBM is always required to insure discovery of problems that arise with time, like deterioration failure of components within the population of devices.

Failures may be discovered during the periodic tests, but the counting also includes failures discovered via non-testing misoperations or other field events that show a degradation or failure of a device in the population, or a design problem.

The owner(s) of the population of devices must document their management process of this program. N They must review the results of field experience and maintenance results every year to insure that the extension criteria are still met. Maintenance data for at least 30 of the devices in the population must be available. If the failure or misoperation rate is seen to rise above the acceptable 4% threshold, the owners must start and document a mitigation program to achieve the failure rate threshold within 3 years.

9 Auditing Considerations

As the Standard becomes mandatory and enforceable, responsible managers and engineers must focus not only on how to comply, but how to document compliance for an auditor. Users need documentation of the program they have chosen and how they are carrying it out. Doing the right work is not enough – if there is no written or concrete proof of performance of all the details, the auditor may treat the implementation as noncompliant. This must trigger a lot of thought, planning, and software application design to keep track of the program *and the activities to carry out the program*.

1) The user needs a document that describes the details of the chosen maintenance program, including listing of covered equipment, eligibility of Protection System elements for the chosen approaches, and functional procedures for testing and documentation. The program must recognize the core requirement that no part of the NERC-defined Protection System is left unchecked.

2) For all time based testing, the owner needs written or electronic records that show details of which tests were performed, and when, by whom, on which components. The record must show that all required maintenance tests are performed, time gaps within the allowed intervals are managed, and test failures are corrected.

3) For CBM, the owner needs a design document that shows how the products and their protection system application meet the requirements stated in Tables 1(b) or 1(c) that we reviewed above. For Table 1(c) compliance, monitoring map help from relay and product vendors will make the documentation task more practical for users. In general, this documentation will be massive unless the user designs new installations according to documented design-controlled standards whose site-specific variations are limited and also documented.

4) For PBM, the TBM records the owner needed in any case should be organized to show basis for time extensions described in Section 7 above, including annual evaluations of maintenance results showing continued good performance and/or action to mitigate problems.

10 Conclusions

The draft NERC PRC-005-2 Protection System Maintenance Standard may show changes as it passes through the industry comment and response process now taking place. However, it will later become mandatory and enforceable, as required by FERC. The deployment will include an implementation plan, giving protection system owners time to develop approaches and become compliant.

A time based maintenance program with prescribed activities and intervals is always allowed, with proper documentation. However, this may prove to be costly and inefficient over time. Owners may need to document a compliant TBM program, and to tighten the operation of data gathering systems in the organization that prove the program is being carried out without gaps. Once the data is compiled, the maintenance activities of reliable legacy (or newer) relays and components can be extended using a PBM program as described in Section 8.

New Protection System designs can take advantage of condition based maintenance approaches described in this paper to reduce future maintenance and data gathering work, or even eliminate most of it. Now is the time to evaluate the opportunity and to develop compliant design standards, as well to document those designs and to develop automated field data gathering systems.

The industry can follow the evolution and deployment of the new Standard via the links to the NERC web site in Section 7 of this paper.

11 Acknowledgement

The members of the Standards Drafting Team for PRC-005-2 are:

- Charles Rogers, Consumers Energy, Chairman
- John Anderson, Xcel Energy
- Merle (Rick) Ashton, Tri-State Generation and Transmission Association
- Bob Bentert, Florida Power and Light
- Al Calafiore, NERC Staff
- John Ciufo, Hydro One
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- Sam Francis, Oncor Energy Delivery
- Carol Gerou, Midwest Reliability Organization
- Russell Hardison, TVA
- David Harper, NRG Texas Maintenance Services
- John Kruse, Exelon
- Mark Peterson, Great River Energy
- William Schultz, Southern Company Generation
- Leonard Swanson, National Grid USA
- Eric Udren, Quanta Technology
- Philip Winston, Georgia Power Company
- John Zipp, ITC Holdings

In addition, twenty five others have attended at least one, and usually several, Standards Drafting Team meetings, and have all contributed significantly to the work of the Standards Drafting Team.

Eric A. Udren has a 40 year distinguished career in design and application of protective relaying, utility substation control, and communications systems. He programmed the world's first computer based transmission line relay, led software development of the world's first LAN-based substation protection and control system, and managed development and application at Westinghouse, ABB, and Eaton Electrical. He has worked with utilities to develop new substation protection and control designs as a consultant since 2004. He is now Executive Advisor with Quanta Technology and is based in Pittsburgh.

Eric is IEEE Fellow, and chairs multiple standards working groups at IEEE Power System Relaying Committee. He is US Technical Advisor for IEC relay standards; and is member of the IEC 61850 substation communications protocol WG. Eric serves on the North American Electric Reliability Corporation (NERC) System Protection and Control Task Force, and Protection System Maintenance Standard Drafting Team. He has written and presented over 50 technical papers and book chapters. He can be reached at eudren@quanta-technology.com.

Charles W. Rogers, a Principal Engineer at Consumers Energy, has worked there since 1978, primarily responsible for a broad spectrum of activities related to transmission system protection. In addition to general protection of transmission systems, he has been responsible for the interconnection protection of distributed generators (since 1980) and for all switching surge analysis activities at Consumers (since 1985). He is currently responsible for managing and coordinating all NERC compliance activities for the transmission and distribution functions at Consumers Energy.

A Senior Member of IEEE, Charles has been extremely active on the IEEE Standards Coordinating Committee 21 P1547 working group, developing national standards related to the interconnection of distributed generation since 1997.

Charles led the ECAR investigation into the August 14, 2003 blackout, and, from 2004 through mid-2008, was the Chairman of the NERC System Protection and Control Task Force. He was the Chairman of the NERC Standard Drafting Team that developed NERC Standard PRC-023-1 – Transmission Relay Loadability, and currently chairs the NERC Standard Drafting Team that is developing the emergent NERC Standard PRC-005-1 – Protection System Maintenance.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. Standards Committee approves SAR for posting on June 5, 2007.
2. The SAR was posted for comment from June 11, 2007–July 10, 2007.
3. The SC approves development of the standard on August 13, 2007.
4. Drafting team posts first draft for comments (July 23, 2009).

Description of Current Draft:
This is the initial draft of the Standard. This standard merges previous standards PRC-005-0, PRC-008-0, PRC-011-0, and PRC-017-0. It also addresses FERC comments from Order 693, and addresses observations from the NERC System Protection and Control Task Force, as presented in *NERC SPCTF Assessment of Standards: PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs, PRC-011-0 — UVLS System Maintenance and Testing, PRC-017-0 — Special Protection System Maintenance and Testing.*

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post response to comments and second draft of standard and associated documents.	To be determined.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Protection System Maintenance Program (PSMP) — An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program can include:

- Verification — A means of determining that the component is functioning correctly.
- Monitoring — Observation of the routine in-service operation of the component.
- Testing — Application of signals to a component to observe functional performance or output behavior, or to diagnose problems.
- Physical inspection — To detect visible signs of component failure, reduced performance and degradation.
- Calibration — Adjustment of the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
- Upkeep — Routine activities necessary to assure that the component remains in good working order and implementation of any manufacturer’s hardware and software service advisories which are relevant to the application of the device.
- Restoration — The actions to restore proper operation of malfunctioning components.

Protection System (modification) — Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing inputs to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices.

A. Introduction

1. **Title: Protection System Maintenance**

2. **Number: PRC-005-2**

3. **Purpose:** To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Transmission Owners

   4.1.2 Generator Owners

   4.1.3 Distribution Providers

   4.2. Facilities:

   4.2.1 Protection Systems that are applied on, or are designed to provide protection for the BES.

   4.2.2 Protection System components used for underfrequency load-shedding systems which are installed per ERO underfrequency load-shedding requirements.

   4.2.3 Protection System components used for undervoltage load-shedding systems which are installed to prevent system voltage collapse or voltage instability for BES reliability.

   4.2.4 Protection System components which is installed as a Special Protection System for BES reliability.

   4.2.5 Protection Systems for Generator Facilities that are part of the BES, including:

   4.2.5.1 Protection system components that act to trip the generator either directly or via generator lockout or auxiliary tripping relays.

   4.2.5.2 Protection systems for generator step-up transformers for generators that are part of the BES.

   4.2.5.3 Protection systems for transformers connecting aggregated generation, where the aggregated generation is part of the BES (e.g., transformers connecting facilities such as wind-farms to the BES).

   4.2.5.4 Protection systems for generator-connected station service transformers for generators that are part of the BES.

   4.2.5.5 Protection systems for system-connected station service transformers for generators that are part of the BES.

5. **(Proposed) Effective Date: TBD**

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems that use measurements of voltage, current, frequency and/or phase angle to determine anomalies and to trip a portion of the BES[1] and that are applied on, or are designed to provide protection for the BES. The PSMP shall meet the following criteria: *[Violation Risk Factor: TBD] [Time Horizon: Long Term Planning]*

1.1. For each component used in each Protection System, include all maintenance activities specified in Tables 1a, 1b, and 1c.

1.2. Identify whether each Protection System component is addressed through time-based, condition-based, performance-based, or a combination of these maintenance methods and identify the associated maintenance interval.

1.3. Include all batteries associated with a Protection System in a time-based program.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses condition-based maintenance intervals in its PSMP for partially or fully monitored Protection Systems shall ensure the components to which the condition-based criteria are applied (as specified in Tables 1b or 1c), possess the necessary monitoring attributes. *[Violation Risk Factor: TBD] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses performance-based maintenance intervals in its PSMP shall follow the procedure established in PRC-005 Attachment A. *[Violation Risk Factor: TBD] [Time Horizon: Long Term Planning]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, including identification of the resolution of all maintenance correctible issues[2] as follows: *[Violation Risk Factor: TBD] [Time Horizon: Long Term Planning]*

4.1. For time-based or condition-based maintenance programs perform the Maintenance activities detailed in Table 1 (for the appropriate monitoring level(s)) for all Protection System components within maximum allowable intervals not to exceed those established in Tables 1a, 1b, and 1c.

4.2. For performance-based maintenance programs perform the maintenance activities detailed in Table 1 (for the appropriate monitoring level(s)) for all Protection System components in accordance within the maximum allowable intervals established per Requirement R3.

C. Measures (TBD)

[1] Devices that sense non-electrical conditions, such as thermal or transformer sudden pressure relays, are not included within the scope of this standard**.**

[2] A maintenance correctable issue is a failure of a device to operate within design parameters that can be restored to functional order by calibration, repair or replacement.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for two maintenance intervals for the Protection System components.

The Compliance Enforcement Authority shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

2. Violation Severity Levels — TBD

E. Regional Differences

None

F. Supplemental Reference Documents

The following documents present a detailed discussion about determination of maintenance intervals and other useful information regarding establishment of a maintenance program.

1. PRC-005-2 Protection System Maintenance Supplementary Reference — July 2009.
2. NERC Protection System Maintenance Standard PRC-005-2 FREQUENTLY ASKED QUESTIONS — Practical Compliance and Implementation DRAFT 1.0 — June 2009

Version History

Version	Date	Action	Change Tracking

Table 1a — Level 1 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems **General Description:** Protection System components which do not have self-monitoring alarms, or if self-monitoring alarms are available, the alarms are not transmitted to a location where action can be taken for alarmed failures.		
Type of Component	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	6 Calendar Years	Test and calibrate the relays (other than microprocessor relays) with simulated electrical inputs. (Note 1) Verify proper functioning of the relay trip outputs. For microprocessor relays verify proper functioning of the A/D converters (Note 2) Verify that settings are as specified.
Voltage and Current Sensing Devices Inputs to Protective Relays	12 Calendar Years	Verify proper functioning of the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays
Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS)	3 Months	Verify the continuity of the breaker trip circuit including trip coil (except for protection system control circuitry associated with breakers that remain open for the entire “maintenance interval” period”)
Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS)	6 Calendar Years	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System.
Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only)	(when the associated UVLS or UFLS system is maintained)	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System.

Table 1a — Level 1 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems **General Description:** Protection System components which do not have self-monitoring alarms, or if self-monitoring alarms are available, the alarms are not transmitted to a location where action can be taken for alarmed failures.		
Type of Component	**Maximum Maintenance Interval**	**Maintenance Activities**
Station dc supply (that has as a component any type of battery)	3 Months	Verify proper electrolyte level (excluding valve-regulated lead acid batteries). Verify proper voltage of the station battery. Verify that no dc supply grounds are present.
Station dc supply (that has as a component any type of battery)	18 Months	Verify proper voltage of each individual cell or unit in the station battery. Verify that station battery charger provides the correct float and equalize voltages. Verify continuity and cell integrity of entire battery. Perform a visual cell inspection of all cells for “cell condition” (where cells are visible) or measurement of cell/unit internal ohmic values (where cells are not visible). Measure that specific gravity and temperature of each cell is within tolerance(where applicable) Verify cell to cell and terminal connection resistance is within tolerance Inspect the structural integrity of the battery rack.
Station dc supply (that has as a component Valve Regulated Lead-Acid batteries)	3 Calendar Years - or - 3 Months	Verify that the station battery can perform as designed by conducting a performance or service capacity test of the entire battery bank. (3 calendar years) - or - Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. (3 months)

Table 1a — Level 1 Monitoring **Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems** **General Description:** Protection System components which do not have self-monitoring alarms, or if self-monitoring alarms are available, the alarms are not transmitted to a location where action can be taken for alarmed failures.		
Type of Component	**Maximum Maintenance Interval**	**Maintenance Activities**
Station dc supply (that has as a component Vented Lead-Acid Batteries)	6 Calendar Years - or - 18 Months	Verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank. (6 calendar years) - or - Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. (18 Months)
Station dc supply (that has as a component Nickel-Cadmium batteries)	6 Calendar Years	Verify that the substation battery can perform as designed by conducting a performance service, or modified performance capacity test of the entire battery bank.
Station dc supply (that uses a battery and charger)	6 Calendar Years	Verify that the battery charger can perform as designed by testing that the charger will provide full rated current and will properly current-limit.
Station dc Supply (battery is not used)	18 Months	Verify proper voltage of the station dc supply Verify that no dc supply grounds are present. Perform a visual inspection, of all components of the station dc supply to verify that the physical condition of the station dc supply is as desired and any visual inspection if required by the manufacturer on the condition of the dc supply that is the source of dc power when ac power is unavailable. Verify where applicable the proper voltage level of each component of the station dc supply. Verify the correct operation of ac powered dc power supplies. Verify the continuity of all circuit connections that can be affected by wear or corrosion.
Station dc Supply (used only for UVLS or UFLS)	(when the associated UVLS or UFLS system is maintained)	Verify proper voltage of the dc supply.

Table 1a — Level 1 Monitoring

Maximum Allowable Testing Intervals and Maintenance Activities for Unmonitored Protection Systems

General Description: Protection System components which do not have self-monitoring alarms, or if self-monitoring alarms are available, the alarms are not transmitted to a location where action can be taken for alarmed failures.

Type of Component	Maximum Maintenance Interval	Maintenance Activities
Protection system communications equipment and channels.	3 Months	Verify that the Protection System communications monitoring and alarms reflect the intended communications system condition by means of a substation inspection.
Protection system communications equipment and channels.	6 Calendar Years	Verify that the performance of the channel and the quality of the channel meets performance criteria, such as via measurement of signal level, reflected power, or data error rate. Verify proper functioning of communications equipment outputs.
UVLS and UFLS relays that comprise a protection scheme distributed over the power system	6 Calendar Years	Test and calibrate the relays (other than microprocessor relays) with simulated electrical inputs. (Note 1) Verify proper functioning of the relay trip outputs. For microprocessor relays verify the proper functioning of the A/D converters (Note 2) Verify that settings are as specified.
Relay sensing for Centralized UFLS or UVLS systems	See Maintenance Activities	Perform all of the Maintenance activities listed above as established for components of the UFLS or UVLS systems at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the UFLS or UVLS components whose operation leads to that control action must each be verified.
SPS	See Maintenance Activities	Perform all of the Maintenance activities listed above as established for components of the SPS at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the SPS components whose operation leads to that control action must each be verified.

Table 1b — Condition-Based Maintenance - Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components **General Description:** Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 2 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	Includes internal self diagnosis and alarm capability, which must assert for power supply failures. Includes input voltage or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming.	12 Calendar Years	Verify the status of relays is normal with no alarms indicated. Verify the proper functioning of the A/D converters within the relay by testing or comparing values against other devices. Verify proper functioning of the relay trip outputs. Verify that settings are as specified. Verify that the relay alarms will be received at the location where action can be taken. See Note 2.
Voltage and Current Sensing Devices - Inputs to Protective Relays	No Level 2 monitoring attributes are defined – use Level 1 Maintenance Activities	12 Calendar Years	Verify the proper functioning of current and voltage circuit inputs from the voltage and current sensing devices to the protective relays
Protection System Control Circuitry (Trip Coils and Auxiliary Relays)	No Level 2 monitoring attributes are defined – use Level 1 Maintenance Activities and intervals	6 Calendar Years	Verify that each breaker trip coil, each auxiliary relay, and each lockout relay is electrically operated within this time interval.
Protection System Control Circuitry (Trip Circuits) (except for UFLS/UVLS)	Monitoring and alarming of continuity of trip coil(s)	12 Calendar Years	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System. Verify that the relay alarms will be received at the location where action can be taken.

Table 1b — Condition-Based Maintenance - Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components **General Description:** Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 2 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only)	Monitoring and alarming of continuity of trip coil(s)	(when the associated UVLS or UFLS system is maintained)	Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System. (Verification does not require actual tripping of circuit breakers or interrupting devices.) Verify that the relay alarms will be received at the location where action can be taken.
Station dc supply (that has as a component any type of battery)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	3 Months	Verify proper electrolyte level (excluding Valve-Regulated Lead Acid batteries).
Station dc supply (that has as a component any type of battery)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	18 Months	Verify proper voltage of each individual cell or unit in the station battery. Verify that station battery charger provides the correct float and equalize voltages. Verify electrical continuity of the entire battery. Perform a visual cell inspection of all cells for “cell condition” (where cells are visible) or measurement of cell/unit internal ohmic values. (where cells are not visible) Measure that specific gravity and temperature of each cell is within tolerance. (where applicable) Verify cell to cell and terminal connection resistance is within tolerance. Inspect the structural integrity of the battery rack. Verify that the battery voltage and dc supply ground alarms will be received at the location where action can be taken.

Table 1b — Condition-Based Maintenance - Level 2 Monitoring

Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components

General Description: Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.

Type of Component	Level 2 Monitoring Attributes for Component	Maximum Maintenance Interval	Maintenance Activities
Station dc supply (that has as a component Valve Regulated Lead-Acid batteries)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	3 Calendar Years - or - 3 Months	Verify that the station battery can perform as designed by conducting a performance or service capacity test of the entire battery bank. (3 calendar years) - or - Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. (3 months)
Station dc supply (that has as a component Vented Lead-Acid batteries)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	6 Calendar Years - or - 18 Months	Verify that the substation battery can perform as designed by conducting a performance service, or modified performance capacity test of the entire battery bank. (6 calendar years) - or - Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline. (18 Months)
Station dc supply (that has as a component Nickel-Cadmium batteries)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	6 Calendar Years	Verify that the substation battery can perform as designed by conducting a performance service, or modified performance capacity test of the entire battery bank.
Station dc supply (that uses a battery and charger)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	6 Calendar Years	Verify that the battery charger can perform as designed by testing that the charger will provide full rated current and will properly current-limit.

Table 1b — Condition-Based Maintenance - Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components **General Description:** Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 2 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Station dc Supply (battery is not used)	Monitoring and alarming of the station dc supply voltage. Detection and alarming of dc grounds.	18 Months	Verify proper voltage of the station dc supply, and where applicable, of each component of the station dc supply. Verify the proper operation of ac powered dc power supplies. Verify the continuity of all circuit connections that can be affected by wear or corrosion. Perform a visual inspection, of all components of the station dc supply to verify that the physical condition of the station dc supply is as desired and any visual inspection if required by the manufacturer on the condition of the dc supply that is the source of dc power when ac power is unavailable. Verify that the station dc supply voltage and dc supply ground alarms will be received at a location where action can be taken.
Station dc Supply (used only for UVLS or UFLS)	No Level 2 monitoring attributes are defined – use Level 1 Maintenance Activities and intervals	(when the associated UVLS or UFLS system is maintained)	Verify proper voltage of the dc supply
Protection system communications equipment and channels.	Monitoring and alarming of protection communications system by mechanisms that check for presence of the communications channel.	12 Calendar Years	Verify that the performance of the channel and the quality of the channel meets performance criteria, such as via measurement of signal level, reflected power, or data error rate. Verify proper functioning of communications equipment outputs. Verify proper functioning of alarm notification.

Table 1b — Condition-Based Maintenance - Level 2 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Partially Monitored Protection System Components General Description: Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 2 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
UVLS and UFLS relays that comprise a protection scheme distributed over the power system.	Includes internal self diagnosis and alarm capability, which must assert for power supply failures. Includes input voltage or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming.	12 Calendar Years	Verify the status of relays as in service with no alarms. Verify the proper function of the A/D converters (if included in relay). Verify proper functioning of the relay trip outputs. Verify that settings are as specified. Verify that the relay alarms will be received at the location where action can be taken.
Relay sensing for centralized UFLS or UVLS systems.	See the attributes of Level 1 Monitoring for the individual components of the SPS	See Maintenance Intervals for the individual components of the UFLS/UVLS	Perform all of the Maintenance activities listed above as established for components of the UFLS or UVLS systems at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the UFLS or UVLS components whose operation leads to that control action must each be verified.
SPS	See the attributes of Level 1 Monitoring for the individual components of the SPS	See Maintenance Intervals for the individual components of the SPS	Perform all of the Maintenance activities listed above as established for components of the SPS, at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the SPS components whose operation leads to that control action must each be verified.

Table 1c — Condition-based Maintenance — Level 3 Monitoring **Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems** **General Description:** Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protective Relays	The relay A/D converters are continuously monitored and alarmed.	Continuous	Continuous verification of the status of the relays. (Note 2) Alarm on change of settings.
Protective Relays with trip contacts	All Level attributes, except relay possesses mechanical output contacts.	12 Calendar Years	Verify proper functioning of the relay trip contacts.
Voltage and Current Sensing Devices Inputs to Protective Relays	Verification of the ac analog values (magnitude and phase angle) measured by the microprocessor relay or comparable device, by comparing against other measurements using other instrument transformers.	Continuous	Continuous verification and comparison of the current and voltage signals from the voltage and current sensing devices of the Protection System.
Protection System Control Circuitry (Trip Coils and Auxiliary Relays)	No Level 3 monitoring attributes are defined – use Level 2 Maintenance Activities and intervals	6 Calendar Years	Each breaker trip coil, each auxiliary relay, and each lockout relay must be electrically operated within this time interval.

Table 1c — Condition-based Maintenance — Level 3 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems **General Description:** Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Protection System Control Circuitry (Trip Circuits)	Monitoring of the continuity of breaker trip circuits (with alarming for non-continuity), along with the presence of tripping voltage supply all the way from relay terminals (or from inside the relay) through to the trip coil, including any auxiliary contacts essential to proper Protection System operation. If a trip circuit comprises multiple paths, each of the paths must be monitored, including monitoring of the operating coil circuit(s) and the tripping circuits of auxiliary tripping relays and lockout relays.	Continuous	Continuous monitoring of trip voltage and trip path integrity of entire trip circuit is provided with alarming to remote terminal unit upon any failure of the trip path.

Table 1c — Condition-based Maintenance — Level 3 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems			
General Description: Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Station dc Supply (any battery technology)	Monitoring and alarming the station dc supply status, including, for station dc supplies that have as a component a battery, the voltage, specific gravity, electrolyte level, temperature and connectivity (cell to cell and terminal connection resistance) of each cell as well as the battery system terminal voltage and electrical continuity of the overall battery system. Monitoring and alarming if the performance capability of the battery is degraded. Monitoring and alarming the ac powered dc power supply status including low and high voltage and charge rate for station dc supplies that have battery systems. Detection and alarming of dc grounds.	18 Months	Verify that station battery charger operation provides the correct float and equalize voltages Perform a visual inspection of the station battery and charger, individual cells (including electrolyte level), connections, and racks to verify that the physical condition of the battery is as desired, and that no associated alarm lamps are illuminated.

Table 1c — Condition-based Maintenance — Level 3 Monitoring

Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems

General Description: Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.

Type of Component	Level 3 Monitoring Attributes for Component	Maximum Maintenance Interval	Maintenance Activities
Station dc supply (that uses a battery and charger)	Monitoring and alarming the station dc supply status, including, for station dc supplies that have as a component a battery, the voltage, specific gravity, electrolyte level, temperature and connectivity (cell to cell and terminal connection resistance) of each cell as well as the battery system terminal voltage and electrical continuity of the overall battery system. Monitoring and alarming if the performance capability of the battery is degraded. Monitoring and alarming the ac powered dc power supply status including low and high voltage and charge rate for station dc supplies that have battery systems. Detection and alarming of dc grounds.	6 Calendar Years	Verify that the battery charger can perform as designed by testing that the charger will provide full rated current and will properly current-limit.

Table 1c — Condition-based Maintenance — Level 3 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems **General Description:** Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Station dc Supply (battery is not used)	Monitoring and alarming the station dc supply status, including output voltage of the dc supply. Monitoring and alarming if the performance capability of the dc supply is degraded. Detection and alarming of dc grounds.	Continuous	Continuous verification of the status of the station dc supply and its ability to deliver dc power when required, is provided.
Station dc Supply (used only for UVLS or UFLS)	No Level 3 monitoring attributes are defined – use Level 2 Maintenance Activities and intervals	(when the associated UVLS or UFLS system is maintained)	Verify proper voltage of the dc supply
Protection system telecommunications equipment and channels.	Evaluating the performance of the channel and its interface to protective relays to determine the quality of the channel and alarming if the channel does not meet performance criteria	Continuous	Continuous verification that the performance and quality of the channel meets performance criteria is provided. Continuous verification of the communications equipment alarm system is provided.
UVLS and UFLS relays that comprise a protection scheme distributed over the power system.	The relay A/D converters are continuously monitored and alarmed.	Continuous	Continuous verification of the status of the relays. (Note 2) Alarm on change of settings. Verification does not require actual tripping of circuit breakers or interrupting devices.

Table 1c — Condition-based Maintenance — Level 3 Monitoring Maximum Allowable Testing Intervals and Maintenance Activities for Fully Monitored Protection Systems **General Description:** Protection System components in which every function required for correct operation of that component is continuously monitored and verified, and detected maintenance-correctable issues reported. Level 3 Monitored Protection Systems also includes verification of the means by which alarms and monitored values are transmitted to a location where action can be taken. Detected maintenance correctable issues for Level 3 Monitored Protection Systems must be reported within 1 hour or less of the maintenance-correctable issue occurring, to a location where action can be taken. Level 3 Monitoring includes all elements of Level 2 Monitoring, with additional monitoring attributes as listed below for the individual type of component.			
Type of Component	**Level 3 Monitoring Attributes for Component**	**Maximum Maintenance Interval**	**Maintenance Activities**
Relay sensing for centralized UFLS or UVLS systems.	See the attributes of Level 3 Monitoring for the individual components of the UFLS/UVLS	See Maintenance Activities	Perform all of the Maintenance activities listed above as established for components of the UFLS or UVLS systems at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the UFLS or UVLS components whose operation leads to that control action must each be verified.
SPS	See the attributes of Level 3 Monitoring for the individual components of the SPS	See Maintenance Activities	Perform all of the Maintenance activities listed above as established for components of the SPS at the intervals established for those individual components. The output action may be breaker tripping, or other control action that must be verified, but may be verified in overlapping segments. A grouped output control action need be verified only once within the specified time interval, but all of the SPS components whose operation leads to that control action must each be verified.

Notes for Table 1a, Table 1b, and Table 1c

1. For some Protection System components, adjustment is required to bring measurement accuracy within parameters established by the asset owner based on the specific application of the component. A calibration failure is the result if testing finds the specified parameters to be out of tolerance.
2. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but power system input values must be verified as correct within the Table intervals. The integrity of the digital inputs and outputs will be verified with the Protection System Control Circuitry.

PRC-005 — Attachment A

Criteria for a Performance-Based Protection System Maintenance Program

Purpose: To establish a technical basis for initial and continued use of a performance-based Protection System Maintenance Program (PSMP).

Segment: In this procedure, the term, "segment" is a grouping of Protection Systems or component devices from a single manufacturer, with common factors such that consistent performance is expected across the entire population of the segment, and shall only be defined for a population of 60 or more individual components.[3]

To establish the technical justification for the initial use of a performance-based PSMP:

1. Develop a list with a description of components included in each designated segment of the Protection System component population.
2. Maintain the components in each segment according to the time-based maximum allowable intervals established in Table 1 until results of maintenance activities for the segment are available for a minimum of 30 individual components of the segment.
3. Document the maintenance program activities and results for each segment, including maintenance dates and countable events[4] for each included component.
4. Analyze the maintenance program activities and results for each segment to determine the overall performance of the segment and develop maintenance intervals.
5. Determine the maximum allowable maintenance interval for each segment such that the segment experiences countable events on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or all components maintained in the previous year.

To maintain the technical justification for the ongoing use of a performance-based PSMP:

1. At least annually, update the list of Protection System components and segments and/or description if any changes occur within the segment.
2. Perform maintenance on the greater of 5% of the components (addressed in the performance based PSMP) in each segment or 3 individual components within the segment in each year.
3. For the prior year, analyze the maintenance program activities and results for each segment to determine the overall performance of the segment.
4. If the components in a Protection System segment maintained through a performance-based PSMP experience 4% or more countable events, develop, document, and

[3] Entities with smaller populations of component devices may aggregate their populations to define a segment and shall share all attributes of a single performance-based program for that segment.

[4] Countable events include any failure of a component requiring repair or replacement, any condition discovered during the verification activities in Table 1a through Table 1c which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure.

implement an action plan to reduce the countable events to less than 4% of the segment population within 3 years.

5. Using the prior year's data, determine the maximum allowable maintenance interval for each segment such that the segment experiences countable events on no more than 4% of the components within the segment, for the greater of either the last 30 components maintained or all components maintained in the previous year.