NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL

Protection System Maintenance

A Technical Reference

September 13, 2007

Prepared by the
System Protection and Controls Task Force
of the
NERC Planning Committee

Table of Contents

APPENDICES

This report was approved by the Planning Committee on September 13, 2007, for forwarding to the Standards Committee.

1. Introduction and Summary

NERC currently h as five Protection and Control (PRC) reliability standards that are mandatory and enforceable in the United States. These standards are:

- 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*

While these standards require that applicable entities have a maintenance program for Protection Systems, and that these entities must be able to demonstrate they are carrying out such a program, there are no specifics regarding the technical requirements for Protection System maintenance programs. Furthermore, FERC Order 693 directed additional modifications respective to Protection System maintenance programs. The System Protection and Control Task Force (SPCTF) developed assessments of these standards (Appendices A and B), which included respective technical information discussed in FERC Order 693[1]. The FERC Order 693 and the SPCTF technical assessments encourage a single, merged standard, and SPCTF assessment calls for more specific and measurable requirements.

The SPCTF recognizes that all four types of Protection Systems addressed by the legacy standards utilize the same types of protective relays, instrument transformers, communications systems, programmable logic controllers, and battery power supply systems. Therefore, the program of maintenance requirements given in this technical reference applies to all four types of protection systems. A few specific implementation details that apply to only certain system types are highlighted in the requirements.

2. Need for Verifying Protection System Performance

Protective relays have been described as silent sentinels, and do not generally demonstrate their performance until a fault or other power system problem requires that they operate to protect power system elements, or even the entire Bulk Electric System. Lacking faults or system problems, the protection systems may not operate for extended periods. A misoperation - a false operation of a protection system or a failure of the protection system to operate when needed - can result in equipment damage, personnel hazards, and wide area disturbances or unnecessary customer outages. A maintenance or testing program is used to determine the performance and availability of protection systems.

Typically, utilities have tested protection systems at fixed time intervals, unless they had some incidental evidence that a particular protection system was not behaving as expected. Testing practices vary widely across the industry. Testing has included system functionality, calibration of measuring relays, and correctness of settings. Typically, a protection system must be visited at its substation installation site and removed from service for this testing.

2.1 Existing NERC Standards for Protection System Maintenance and Testing

For critical transmission system protection functions, NERC rules have required that each utility or asset owner define a testing program. The starting point is the existing Standard PRC-005, briefly restated as follows:

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1 The Planning Committee approved these documents in March 2007 and June 2007.

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

  PRC-005 is not specific on where the boundaries of the Protection Systems lie. However, the definition of Protection System in the NERC Glossary of Terms indicates what must be included as a minimum.

Definition of *Protection System* (excerpted from the NERC Standards Glossary of Terms): Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.

- *Applicability:* Owners of generation, transmission, and transmission Protection Systems.
- *Requirements:* The owner shall have a documented maintenance program, with procedures, and with test intervals supported by some basis. The owner must keep records showing that the maintenance and testing was actually performed per procedures at the specified intervals, for at least three years.

For proposed new maintenance requirements defined below, the term Bulk Electric System (BES) is replaced by a specification of Protection Systems for which the requirements apply as given in Section 2.2 below.

The purpose and applicability of PRC-005 and the other maintenance standards will remain valid for the foreseeable future. Furthermore, it will still be required to have a documented maintenance program, with procedures and records. The present document looks at setting maximum allowable time intervals and allowing continuation of existing programs conducted on a technically sound basis, while opening new options for how this maintenance program can take advantage of features of new relays. The newest relays have self-monitoring capabilities that open new options for verifying relay performance with reduced on-site testing.

2.2 Applicability of New Protection System Maintenance Standards

Maintenance requirements and approaches presented in Sections 8 through 14 below are intended to apply to all of the following facilities:

1. Protection Systems for transmission equipment operated at 200 kV and above.
2. Protection Systems for transmission equipment operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the electric system.
3. Protection Systems for transformers with low voltage terminals connected at 200 kV and above.
4. Protection Systems for transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the electric system.
5. Protection Systems of generator step-up transformers for individual generators of greater than 20 MVA (gross nameplate rating) with high-side terminals connected to facilities defined in items 1 or 2 above, and all generator step-up transformers in generation plants greater than 75 MVA (gross aggregate nameplate rating).
6. Protection Systems of generator auxiliary load transformers (regardless of where they are connected) in generation plants greater than 75 MVA (gross aggregate nameplate rating).
7. Protection Systems for individual generators of greater than 20 MVA (gross nameplate rating) connected through step-up transformers as described in (5) and all generators greater than 20 MVA (gross nameplate rating) in generation plants greater than 75 MVA (gross aggregate

nameplate rating). The following generator protection functions and system interface protection functions are included:

a. Fault protective functions, including distance functions, voltage-restrained overcurrent functions, or voltage-controlled overcurrent functions
b. Loss-of-field relays
c. Volts-per-hertz relays
d. Negative sequence overcurrent relays
e. Overvoltage and undervoltage protection relays
f. Stator ground relays
g. Communications-based protection systems such as transfer-trip systems
h. Generator differential relays
i. Reverse power relays
j. Frequency relays
k. Out-of-step relays
l. Inadvertent energization protection
m. Breaker failure protection

8. The protection systems, including all applicable protection systems from item 7 above, for the system interface facilities for installations such as wind farms which are aggregated through a single connection point to the system, greater than 75 MVA (gross aggregate nameplate rating).
9. Protection Systems for underfrequency load shedding (UFLS) and undervoltage load shedding (UVLS), and special protection schemes (SPS) which are subject to the various NERC Standards, even if connected to the power system at voltages lower than those stated in (1) and (2) above.

3. Relay Product Generations

The likelihood of failure, and the ability to observe the operational state of a critical protection system, both depend on the technological generation of the relays as well as how long they have been in service. Unlike many other transmission asset groups, protection and control systems have seen dramatic technological changes spanning several generations. During the past 20 years, major functional advances are primarily due to the introduction of microprocessor technology for power system devices such as primary measuring relays, monitoring devices, control systems, and telecommunications equipment.

Modern microprocessor based relays have six significant traits that impact a maintenance strategy:

1. Self monitoring capability – the processors can check themselves, peripheral circuits, and some connected substation inputs and outputs such as trip coil continuity. Most relay users are aware that these relays have self monitoring, but are not focusing on exactly what parts are actually monitored. As explained further below, every element critical to the protection system must be monitored, or else verified periodically.
2. Ability to capture fault records showing how the protection system responded to a fault in its zone of protection, or to a nearby fault for which it is required not to operate.

3. Ability to meter currents and voltages, as well as status of connected circuit breakers, continuously during non-fault times. The relays can compute values such as MW and MVAR line flows that are sometimes used for operational purposes such as SCADA.
4. Data communications via ports that provide remote access to all of the results of protection system monitoring, recording, and measurement.
5. Ability to trip or close circuit breakers and switches through the protection system outputs, on command from remote data communications messages or from relay front panel button requests.
6. Construction from electronic components some of which have shorter technical life or service life than electromechanical components of prior protection system generations.

4. Definitions

We explain how five key words are defined for use in the following:

- Maintenance – An ongoing program by which Protection System function is proved, and restored if needed. A maintenance program comprises verification of individual protection systems, which in turn is achieved by of a combination of monitoring, testing, and calibration.
- Verification – A means of determining that the Protection System or component is functioning correctly and is fit for service.
- Monitoring – Observation of the correctness of routine in-service operation of the Protection System or component.
- Testing – Application of signals to a Protection System or component removed from service, to observe functional performance or output behavior.
- Calibration – Adjustment of the operating threshold or measurement accuracy of a Protection System measuring element to meet manufacturer's specifications or an application accuracy requirement.

Thus, this document will discuss requirements for a maintenance program. Repairs and adjustments are carried out when required. PRC-005-1 language of "maintenance and testing" is no longer used.

5. Time Based Maintenance (TBM) Programs

Time based maintenance is the process in which protection systems are verified according to a time schedule. The scheduled program often calls for relay technicians to travel to the physical site of the relay installation and perform a functional test on protection system components. However, some components of a TBM testing program may be conducted from a remote location – for example, tripping a circuit breaker by communicating a trip command to a microprocessor relay to determine if the entire protection system tripping chain is able to operate the breaker.

6. Condition Based Maintenance (CBM) Programs

Condition based maintenance is the process of gathering and monitoring the information available from modern microprocessor-based relays and other intelligent electronic devices (IEDs) that monitor protection system elements. These relays and IEDs generate monitoring information during normal operation, and the information can be assessed at a convenient location remote from the substation. The information from these relays and IEDs is divided into two major categories:

- Results from background self-monitoring processes, programmed by the manufacturer, or by the user in relay logic settings. The results are presented by alarm contacts or points, front panel indications, and by data communications messages.
- Event logs, captured files, and/or oscillograph records for faults and disturbances, metered values, and binary input status reports. Some of these are available on the relay front panel display, but may be available via data communications ports. Large files of fault information can only be retrieved via data communications. These results comprise a mass of data that must be further analyzed for evidence of the operational condition of the protection system.

Using these two categories of information, the user can develop an effective maintenance program carried out mostly from a central location remote from the substation. This approach offers the following advantages:

- **Non-invasive Maintenance:** The system is kept in its normal operating state, without human intervention for checking. This reduces risk of damage, or risk of leaving the system in an inoperable state after a manual test. Experience has shown that keeping human hands away from equipment known to be working correctly enhances reliability.
- **Virtually Continuous Monitoring:** CBM will report many hardware failure problems for repair within seconds or minutes of when they happen. This reduces the percentage of problems that are discovered through incorrect relaying performance. By contrast, a hardware failure discovered by TBM may have been there for much of the time interval between tests, and there is a good chance that some relays will show health problems by incorrect relaying before being caught in the next test round. The frequent or continuous nature of CBM makes the effective verification interval far shorter than any required TBM maximum interval.

7. Time Based versus Condition Based Maintenance

Time based and condition based maintenance programs are both acceptable, if implemented according to technically sound requirements. Practical programs can employ a *combination of time based and condition based maintenance*. The standard requirements proposed in Sections 8 and 13 introduce the concept of optionally using condition monitoring as a documented element of a maintenance program.

The Federal Energy Regulatory Commission (FERC), in its Order Number 693 Final Rule dated March 16, 2007 (18 CFR Part 40, Docket No. RM06-16-000) on Mandatory Reliability Standards for the Bulk-Power System, directed NERC to submit a modification to PRC-005-1 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. Accordingly, this White Paper proposes specific maximum allowable intervals in Section 8. These maximum intervals define requirements for a time-based maintenance program, and different intervals when specific types of condition monitoring are used.

A key feature of condition-based monitoring is that it effectively reduces the time delay between the moment of a protection failure and time the protection system owner knows about it, for the monitored segments of the protection system. In some cases, the verification is practically continuous – the time interval between verifications is minutes or seconds. Thus, technically sound condition-based verification as specified in Table 1 of Section 8 below meets the time-based verification requirements of the FERC order even more effectively than time-based tests of the same system elements.

The result is that:

- Future NERC standards should permit utilities to use a technically sound approach to testing relays and components by on-site technicians with test sets. This periodic testing should be conducted within maximum time intervals specified in Table 1 below.
- TOs or GOs that wish to take advantage of remote monitoring, data analysis, and control capabilities of modern protection systems can reduce periodic site visits and invasive testing as a maintenance approach. The focus in this case is on defining and documenting a technically complete program according to recommendations made in this document.

8. Maximum Allowable Verification Intervals

The following verification interval requirements show how CBM with newer relay types can reduce the need for many of the tests and substation site visits that older protection systems require. As explained in Appendix D, there are some segments of the protection system that monitoring or data analysis may not verify. Verifying these requires some persistent TBM activity in the maintenance program. However, much of this TBM can be carried out remotely – for example, exercising a circuit breaker through the relay tripping and closing circuits using the relay remote control capabilities via data communications, if there has been no fault or routine operation to demonstrate performance of relay tripping circuits.

8.1 Table of Maximum Allowable Verification Intervals

Table 1 below specifies maximum allowable verification intervals for various generations of protection systems, and categories of equipment that comprise protection systems. The right column indicates verification or testing activities required for each category.

Categories of equipment are illustrated in Figure 1, which shows an example telecommunications-assisted line protection system comprising substation equipment at each terminal, and a telecommunications channel for relaying between the two substations. The numbers in brackets show the categories of subsystems to be verified within the protection system, corresponding to Rows 1 to 5 of Table 1. UFLS and UVLS protection systems and SPS are additional categories in Rows 6 and 7 of Table 1 that are not illustrated in Figure 1.

For each category, Table 1 shows maximum allowable testing intervals for unmonitored, partially monitored, thoroughly monitored, and fully monitored protection systems:

- ***Unmonitored*** – Applies to electromechanical and analog solid state protection systems. However, the telecommunications equipment (Category 5 of Table) used with these legacy systems frequently includes partial or full monitoring capabilities, allowing longer testing intervals for that category of equipment as shown in Row 5
- ***Partially Monitored*** – Applies to microprocessor relays (defined in Note 6 under the Table) and associated protection system components whose self-monitoring alarms are transmitted to a location where action can be taken for alarmed failures. Note 1 under the Table gives the specific monitoring actions required for partial monitoring, to take advantage of these longer allowable

verification intervals. Trip voltage and trip coil continuity is also monitored in partially-monitored protection systems.

- ***Thoroughly Monitored*** – Applies to microprocessor relays and associated protection system components that meet partial monitoring requirements of Note 1, plus additional monitoring of alarms and performance measurement values as specified in Note 2. With these additional monitoring actions, the bulk of the protection system elements that are likely to fail are monitored continuously or frequently, so that maximum allowable verification intervals may be significantly extended. However, even these additional monitoring steps do not assure that every possible failure is detected, so infrequent periodic verification is still required.
- ***Fully Monitored*** – Applies to microprocessor relays and associated protection system components in which every element or function required for correct operation of the protection system is monitored continuously or verified, including verification of the means by which failure alarms or indicators are transmitted to a central location for immediate action. Full monitoring includes all elements of thorough monitoring. For fully-monitored systems or segments, documentation is required that shows how every possible failure, including a failure in the verification or monitoring system or alarming channel, is detected.

Section 9 describes a performance-based maintenance program which can be used to justify maintenance intervals other than those described in Table 1.

Section 10 describes segments of the protection system, and overlapping considerations for full verification of the protection system by segments. Segments refer to pieces of the protection system, which can range from a single device to a panel to an entire substation.

Section 11 describes how relay operating records can serve as a basis for verification, reducing the frequency of manual testing.

Section 13 describes how a cooperative effort of relay manufacturers and protection system users can improve the coverage of self-monitoring functions, leading to full monitoring of for the bulk of the protection system, and eventual elimination of manual verification or testing.

8.2 Retention of Records

PRC-005-1 describes a reporting or auditing cycle of one year and retention of records for three years. However, with a three year retention cycle, the records of verification for a protection system will typically be discarded before the next verification, leaving no record of what was done if a misoperation or failure is to be analyzed. Therefore, verification records for a particular protection system or component should be retained at least until successful completion of the next verification of that system or component.

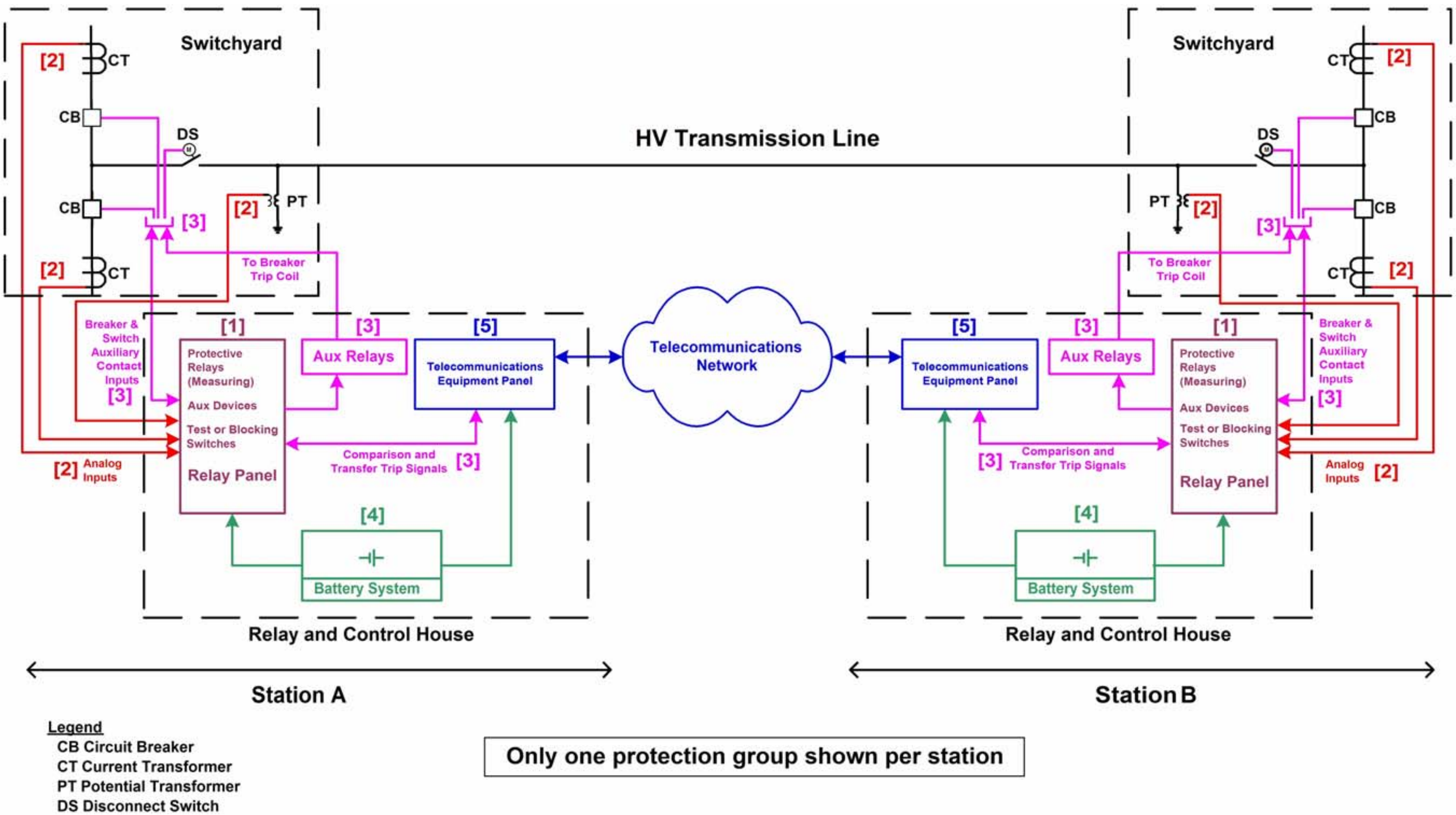

Figure 1 – Transmission Line Protection System with Identification of Equipment Categories

Table 1 – Maximum Allowable Testing Intervals by Equipment Category

Category	Component	Maximum Verification Interval				Verification Activities
Reference Figure 1		Un-monitored	Partial Monitoring Note 1	Thorough Monitoring Note 2	Full Monitoring Note 3	
1.	Testing and calibration of protective relays, per Note 7.	5 years	7 years (Notes 1a, 1e, 1f)	10 years (Note 2a)	Continuous Monitoring and Verification	Test the functioning of relays with simulated inputs, including calibration per Note 7. Verify that settings are as specified. See Section 12 for a discussion of verifying settings.
2.	Verification of instrument transformer outputs and correctness of connections to protection system.	7 years	7 years (Notes 1a, 1f)	10 years (Note 2a)	Continuous Monitoring and Verification	Verify the current and voltage signals to the protection system, and instrument transformer circuit grounding
3.	Verification of protection system tripping including circuit breaker tripping, auxiliary tripping relays and devices, lockout relays, telecommunications-assisted tripping schemes, and circuit breaker status indication required for correct operation of protection system.	5 years	7 years (Notes 1a, 1b, 1d, 1e, 1f)	10 years (Note 2b)	Continuous Monitoring and Verification	Perform trip tests for the whole system at once, and/or component operating tests with overlapping of component verifications as explained in Section 10. Every operating circuit path must be fully verified, although one check of any path is sufficient. A breaker only need be tripped once per trip coil within the specified Table 1 time interval. Telecommunications-assisted line protection systems may be verified either by end-to-end tests, or by simulating internal or external faults with forced channel signals.
4.	Station battery supply (Note 12)	1 month	7 years (Notes 1b, 1d, 1f)	Continuous Verification (Notes 2b, 2d)	Continuous Monitoring and Verification	Verify voltage of the station battery once a month if not monitored.

Category	Component	Maximum Verification Interval				Verification Activities
Reference Figure 1		Un-monitored	Partial Monitoring Note 1	Thorough Monitoring Note 2	Full Monitoring Note 3	
5.	Protection system telecommunications equipment and channels required for correct operation of protection systems.	6 months	7 years (Notes 1c, 1f)	10 years (Note 2c)	Continuous Monitoring and Verification	Check signal level, signal to noise ratio, or data error rate within the specified interval. This includes testing of any function that inhibits undesired tripping in the event of communications failure detected by partial or thorough monitoring. For partially or thoroughly monitored communications, verify channel adjustments and monitors not verified by telecommunications self-monitoring facilities (such as performance and adjustment of line tuners and traps in power line carrier systems). For thoroughly monitored systems, check for proper functioning of alarm notification.
6.	Testing and calibration of UVLS and UFLS relays that comprise a protection scheme distributed over the power system.	10 years	10 years	10 years	Continuous Monitoring and Verification	Test the functioning of relays with simulated inputs, including calibration per Note 7. Verify that settings are as specified. See Section 12 for a discussion of verifying settings. Verification does not require actual tripping of loads. Verification of the population of load shedding relays is to be distributed over the years of the applicable maximum testing interval See Category 7 (SPS) for verification intervals for UVLS systems which are not distributed, even though UVLS are specifically excluded from the definition of SPS systems.

Category	Component	Maximum Verification Interval				Verification Activities
Reference Figure 1		Un-monitored	Partial Monitoring Note 1	Thorough Monitoring Note 2	Full Monitoring Note 3	
7.	SPS, including verification of end-to-end performance, or relay sensing for centralized UFLS or UVLS systems. See Note 8.	5 years	7 years	10 years	Continuous Monitoring and Verification	Perform all of the verification actions for Categories 1 through 5 above as relevant for components of the SPS, UFLS or UVLS systems. The output action may be breaker tripping, or other control action that must be verified. A grouped output control action need be verified only once within the specified time interval, but all of the SPS, UFLS, or UVLS components whose operation leads to that control action must each be verified.

Notes on Table 1

1. Partial monitoring comprises:

    a. Monitoring of the internal self-monitoring alarm contact of a microprocessor relay as detailed in Note 1 (f) below. A microprocessor relay is defined in Note 6. The alarm must assert in real-time for dc supply or power supply failures.

    b. Monitoring of trip coil continuity and trip voltage by periodic checking of a monitoring light or by an automatic continuity-monitoring means such as the trip coil monitor of the microprocessor relay.

    c. Monitoring and alarming of the functioning of a protection telecommunications system, if used, as detailed in Note 1 (f) below, by periodic checkback test, guard signal, or channel messaging functional indication.

    d. Monitoring of the station battery voltage with associated alarms as detailed in Note 1 (f) below.

    e. Documented confirmation of the correctness of the settings file immediately after any maintenance event that could possibly influence settings:

        i. One or more settings are changed for any reason.
        ii. A relay fails and is repaired or replaced with another unit.
        iii. A relay is upgraded with a new firmware version.

    f. Alarms are supplied to an operations center or a maintenance monitoring center in real time for appropriate action.

2. Thorough monitoring comprises partial monitoring elements of Note 1, plus the following monitoring processes:

    a. Verification of the ac analog values measured by the microprocessor relay, by comparing against other measurements using other instrument transformers. This checking may use relay front panel value displays, or values gathered via data communications. Groupings of other measurements (such as vector summation of bus feeder currents) can be used for comparison if calibration requirements of Note 7 are met.

    b. Monitoring of the continuity of breaker trip circuits, along with the presence of tripping voltage supply all the way from relay terminals (or from inside the relay) though the trip coil, along with each required tripping voltage. If a trip circuit comprises multiple paths that operate in a sequence, each of the paths must be monitored in this way. This includes monitoring of both the operating coil circuit and the tripping circuits of auxiliary tripping relays and lockout relays.

    c. Monitoring of the channel quality for a protection telecommunications system, if used, by monitoring or alarming the signal level, signal to noise ratio, or error rate.

    d. Alarms are supplied in real time to an operations center or a maintenance monitoring center for appropriate action. Specified monitoring or measurement values are either supplied to the operations center or maintenance monitoring center either in real time, or gathered for checking and appropriate action within the unmonitored maximum time interval.

3. Full monitoring of a specific segment requires that every element or function required for correct operation of the protection system is monitored continuously or verified, including verification of the means by which failure alarms and indicators are transmitted to a central location for immediate action. Full monitoring includes all elements of thorough monitoring. Documentation is required that shows how every possible failure, including a failure in the verification or monitoring system or alarming channel, is detected.
4. Every component of the protection system that can impact tripping, including components not named in Table 1, must be verified within the required time interval for Category 3 components.
5. The prescriptive establishment of maximum allowable intervals must include allowance for extensions due to difficulties in obtaining outages to do the necessary testing. This allowance must be carefully developed to assure that it does not, in essence, extend the maximum allowable intervals themselves in the long term. For example, a six-month grace period could be permitted for the protection system owner to accomplish the scheduled program without being found non-compliant; further extensions would require regional approval before the end of the grace period. Another alternative could be to craft an allowance to permit a 1-year extension with the caveat that the average actual testing interval over multiple testing cycles must be no longer than the prescribed interval.
6. Microprocessor relays are defined as those with 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. In particular, note that relays combining comparator-based analog measurement circuits with microprocessors for system logic or timing are classified as analog solid state (or static) relays that are not capable of self-monitoring.
7. Microprocessor relays typically are specified by manufacturers as not requiring calibration, but acceptable measurement of power system input values must be verified within the Table intervals. For other relays, adjustment is required only to bring measurement accuracy within the tolerance stated by the relay manufacturer. Alternatively, the asset owner may document the technical basis for a larger permissible calibration tolerance based on the specific application of the relay.
8. Any Phasor Measurement Unit (PMU) function whose output is used in a protection system or SPS (as opposed to a monitoring task) must be verified as a component in a protection system.
9. Maximum intervals should be substantially reduced, or effective remedial action taken, for problem populations of equipment whose abnormal levels of failures are found by testing or misoperation experience.
10. It is acceptable to use a single test procedure that covers multiple categories of equipment in a protection system. Fault or operating data may be used to achieve some of the verification goals, as explained in Section 11 below.
11. A PRC standard does not require testing of circuit breakers. However, utilities have found that breakers often show problems during relay tests. It is recommended that protection system verification include periodic testing of the actual tripping of connected circuit breakers.
12. In addition to verifying the circuitry that supplies dc to the protection system, the owner must maintain station batteries in accordance with industry standards, or use a performance-based process as Section 9 describes. Battery systems used for UFLS or UVLS systems (but not for any other protection systems addressed within this paper) need be checked only when the associated protection systems are verified.

8.3 Basis for Table 1 Intervals

SPCTF authors collected all available data from Regional Entities (REs) on time intervals recommended for maintenance and test programs. The recommendations vary widely in categorization of relays, defined maintenance actions, and time intervals, precluding development of intervals by averaging. SPCTF also reviewed the 2005 Report [2] of the IEEE Power System Relaying Committee Working Group I-17 (Transmission Relay System Performance Comparison). Review of the I-17 report shows data from a small number of utilities, with no company identification or means of investigating the significance of particular results.

To develop a solid current base of practice, SPCTF surveyed its members regarding their maintenance intervals for electromechanical and microprocessor relays, and asked the members to also provide definitively-known data for other entities. The survey represented 470 GW of peak load, or 64% of the NERC peak load. Maintenance interval averages were compiled by weighting reported intervals according to the size (based on peak load) of the reporting utility. Thus, the averages more accurately represent practices for the large populations of protection systems used across the NERC regions.

The results of this survey with weighted averaging indicate maintenance intervals of 5 years for electromechanical or solid state relays, and 7 years for microprocessor relays.

A number of utilities have extended maintenance intervals for microprocessor relays beyond 7 years, based on favorable experience with the particular products they have installed. To provide a technical basis for such extension, SPCTF authors developed a recommendation of 10 years using the Markov modeling approach from [1] as summarized in Appendix C. The results of this modeling depend on the completeness of self-testing or monitoring. Accordingly, this extended interval is allowed by Table 1 only when such relays are thoroughly monitored as specified in Notes 1 and 2. Thorough monitoring is capable of reporting protection system health issues that are likely to affect performance within the 10 year time interval between verifications.

It is important to note that, according to modeling results, protection system availability barely changes as the maintenance interval is varied below the 10-year mark. Thus, reducing the maintenance interval does not improve protection system availability. With the assumptions of the model regarding how maintenance is carried out, reducing the maintenance interval actually degrades protection system availability.

9. Performance-Based Maintenance Process

In lieu of using the Table 1 intervals, a performance-based maintenance process may be used. A performance-based maintenance process may justify longer maintenance intervals, or require shorter intervals relative to Table 1. In order to use a performance-based maintenance process, the documented maintenance program must include records of repairs, adjustments, and corrections to covered protection systems. Furthermore, the system owner must regularly analyze these records of corrective actions to develop a ranking of causes. Recurrent problems are to be highlighted, and remedial action plans are to be documented to mitigate or eliminate recurrent problems.

Utilities with performance-based maintenance track performance of protection systems, demonstrate how they analyze findings of performance failures and aberrations, and implement continuous improvement actions. Since no maintenance program can ever guarantee that no malfunction can possibly occur, documentation of a performance- based maintenance program would serve the utility well in explaining to regulators and the public a misoperation leading to a major system outage event.

A performance-based maintenance program requires auditing processes like those included in widely used industrial quality systems (such as ***ISO 9001-2000, Quality management systems — Requirements***; or applicable parts of the NIST Baldridge National Quality Program). The audits periodically evaluate:

- The completeness of the documented maintenance process
- Organizational knowledge of and adherence to the process
- Performance metrics and documentation of results
- Remediation of issues
- Demonstration of continuous improvement.

10. Overlapping the Verification of Segments of the Protection System

Table 1 requires that every protection system element be periodically verified. One approach is to test the entire protection scheme as a unit, from voltage and current sources to breaker tripping. For practical ongoing verification, *segments* of the protection system may be tested or monitored individually. The boundaries of the verified segments must *overlap* to insure that there are no gaps in the verification.

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

Appendix D gives an example of how the overlapping of monitoring and tests might be accomplished in a carrier blocking pilot line protection system; it demonstrates monitoring gaps that must be covered by testing.

All of the methodologies expressed within this report may be combined by an entity, as appropriate, to establish and operate a maintenance program. For example, a protection system may be divided into four or more overlapping segments with a different maintenance methodology for each segment:

- Time based maintenance with appropriate maximum verification intervals for categories of equipment as given in the Unmonitored, Partial Monitoring, or Thorough Monitoring columns of Table 1;
- Full monitoring as described in Note 3 of Table 1;
- A performance-based maintenance program as described in Section 9;
- Opportunistic verification using analysis of fault records as described in Section 11

11. Monitoring by Analysis of Fault Records

Many users of microprocessor relays retrieve fault event records and oscillographic records by data communications after a fault. They analyze the data closely if there has been an apparent misoperation, as NERC standards require. Some advanced users have commissioned automatic fault record processing systems that gather and archive the data. They search for evidence of component failures or setting problems hidden behind an operation whose overall outcome seems to be correct. The relay data may be augmented with independently captured digital fault recorder (DFR) data retrieved for the same event.

Fault data analysis comprises a legitimate CBM program that is capable of reducing the need for a manual time-interval based check on protection systems whose operations are analyzed. Even electromechanical protection systems instrumented with DFR channels may achieve some CBM benefit. The completeness of the verification then depends on the number and variety of faults in the vicinity of the relay that produce relay response records, and the specific data captured.

A typical fault record will verify particular parts of certain protection systems in the vicinity of the fault. For a given protection system installation, it may or may not be possible to gather within a reasonable amount of time an ensemble of internal and external fault records that completely verify the protection system.

For example, fault records may verify that the particular relays that tripped are able to trip via the control circuit path that was specifically used to clear that fault. A relay or DFR record may indicate correct operation of the protection communications channel. Furthermore, other nearby protection systems may verify that they restrain from tripping for a fault just outside their respective zones of protection. The ensemble of internal fault and nearby external fault event data can verify major portions of the protection system, and reset the time clock for the Table 1 testing intervals *for the verified components only*.

What can be shown from the records of one operation is very specific and limited. In a panel with multiple relays, only the specific relay(s) whose operation can be observed without ambiguity in the record and the associated wiring paths are verified. Be careful about using fault response data to verify that settings or calibration are correct. Unless records have been captured for multiple faults close to either side of a setting boundary, setting or calibration could still be incorrect.

If fault record data is used to show that portions or all of a protection system have been verified to meet Table 1 requirements, the owner must retain the fault records used, and the maintenance related conclusions drawn from this data and used to defer Table 1 tests, for at least the retention time interval given in Section 8.2.

12. Importance of Relay Settings in Maintenance Programs

In manual testing programs, many utilities depend on pickup value or zone boundary tests to show that the relays have correct settings and calibration. Microprocessor relays, by contrast, provide the means for continuously monitoring measurement accuracy. Furthermore, the relay digitizes inputs from one set of signals to perform all measurement functions in a single self-monitoring microprocessor system. These relays do not require testing or calibration of each setting.

However, incorrect settings may be a bigger risk with microprocessor relays than with older relays. Some microprocessor relays have hundreds or thousands of settings, many of which are critical to protection system performance.

Monitoring does not check measuring element settings. Analysis of fault records may or may not reveal setting problems. To minimize risk of setting errors after commissioning, the user should enforce strict settings data base management, with reconfirmation (manual or automatic) that the installed settings are correct whenever maintenance activity might have changed them. For background and guidance, see [5].

Note 1 (e) of Table 1 requires that for partial or full monitoring, settings must be verified to be correct after a maintenance event that could have disturbed them. To meet this requirement, a settings management process must be established and documented that confirms the correctness of the settings file immediately after any maintenance event that could possibly influence settings:

- One or more settings are changed for any reason.

- A relay fails and is repaired or replaced with another unit.
- A relay is upgraded with a new firmware version.

It is recommended that the managed settings data base also be used for relay coordination studies. In this way, many erroneous settings will show up as apparent misbehavior in a coordination check, and can be corrected before a protection system misbehaves in service.

13. Self-Monitoring Capabilities and Limitations

Microprocessor relay proponents have cited the self-monitoring capabilities of these products for nearly 20 years. Theoretically, any element that is monitored does not need a periodic manual test. A problem today is that the community of manufacturers and users has not created clear documentation of exactly what is and is not monitored. Some unmonitored but critical elements are buried in installed systems that are described as self-monitoring.

Until users are able to document how all parts of a system which are required for the protective functions are monitored or verified (with help from manufacturers), they must continue with the unmonitored, partially monitored, or thoroughly monitored intervals established in Table 1.

Going forward, manufacturers and users can develop mappings of the monitoring within relays, and monitoring coverage by the relay of user circuits connected to the relay terminals. The user-generated monitoring maps and documents are the basis for Full Monitoring as shown in Table 1 and defined in Note 3. With full monitoring, settings integrity must still be managed as described in Section 12.

To enable the use of full monitoring, the manufacturers of the microprocessor-based self-monitoring components in the protection system should publish for the user a document or map that shows:

- How all internal elements of the product are monitored for any failure that could impact protection system performance.
- Which connected circuits are monitored by checks implemented within the product – how to connect and set the product to assure monitoring of these connected circuits, and what circuits or potential problems are not monitored.

With this information in hand, the user can document full monitoring for some or all segments by:

1. Presenting or referencing the product manufacturer documents.
2. Explaining in a system design document the mapping of how every component and circuit that is critical to protection is monitored by the microprocessor product(s) or by other design features.
3. Extending the monitoring to include the alarm transmission facilities through which failures are reported to remote centers for immediate action, so that failures of monitoring or alarming systems also lead to alarms and action.
4. Documenting the plans for verification of any unmonitored elements according to the requirements of Table 1.

14. Notification of Protection System Failures

When a failure occurs in a protection system, power system security may be compromised, and notification of the failure must be conducted in accordance with relevant NERC Standard(s). Knowledge of the failure may impact the system operator's decisions on acceptable loading conditions.

This formal reporting of the failure and repair status to the system operator by the protection system owner also encourages the system owner to execute repairs as rapidly as possible. In some cases, a microprocessor relay or carrier set can be replaced in hours; wiring termination failures may be repaired in a similar time frame. On the other hand, a component in an electromechanical or early generation electronic relay may be difficult to find and may hold up repair for weeks. In some situations, the owner may have to resort to a temporary protection panel, or complete panel replacement.

15. References

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7. "Analysis And Guidelines For Testing Numerical Protection Schemes," Final Report of CIGRE WG 34.10, August 2000.
8. "Use of Preventative Maintenance and System Performance Data to Optimize Scheduled Maintenance Intervals," H. Anderson, R. Loughlin, and J. Zipp, Georgia Tech Protective Relay Conference, May 1996.

Appendix A — Assessment of PRC-005 by SPCTF

The following is the main text of *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*, approved by the Planning Committee on March 21, 2007, for forwarding to the Standards Committee.

Introduction

When the original scope for the System Protection and Control Task Force was developed, one of the assigned items was to review all of the existing PRC-series Reliability Standards, to advise the Planning Committee of our assessment, and to develop Standards Authorization Requests, as appropriate, to address any perceived deficiencies.

This report presents the SPCTF's assessment of PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing. The report includes the SPCTF's understanding of the intent of this standard and contains specific observations relative to the existing standard.

The SPCTF sees the parallel intent for each of the PRC-005, PRC-008, PRC-011, and PRC-017 as being maintenance and testing standards for different protective systems. In fact, PRC-005 & PRC-008, and PRC-011 & PRC-017 have very similar format respectively. Since all protective relay systems require some means of maintenance and testing, it would seem that all protective system maintenance and testing could be included in one standard regardless of scheme type. The SPCTF recommends that these four standards be reduced to one standard covering the issues detailed for PRC-005 on maintenance and testing.

These four standards were developed primarily by translating the requirements of an earlier Phase I Planning Standard; thus they have not been previously subjected to a critical review of the Requirements.

Executive Summary

Reliability standards PRC-005, 008, 011, and 017 are intended to assure that Transmission & Generation Protection Systems are maintained and tested so as to provide reliable performance when responding to abnormal system conditions. It is the responsibility of the Transmission Owner, Generation Owner, and Distribution Provider to ensure the Transmission & Generation Protection Systems are maintained and tested in such a manner that the protective systems operate to fulfill their function.

Only PRC-005 will be commented on in detail although the other three standards have the same concerns.

SPCTF concluded that:

- Applicable to all four standards — The listed requirements do not provide clear and sufficient guidance concerning the maintenance and testing of the Protection Systems to achieve the commonly stated purpose which is "To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested."
- Applicable to PRC-017 — Part of the stated purpose in PRC-017 states: "To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected." The phrase "and misoperations are analyzed and corrected" is not clearly appropriate in a maintenance and testing standard. That is, the purpose is more appropriate in PRC-003 and PRC-004, which relate to the analysis and mitigation of protection system misoperations. Analysis of

correct operations or misoperations may be an integral part of condition-based maintenance processes, but need not be mandated in a maintenance standard.

- Applicable to all four standards — The standards should clearly state which power system elements are being addressed.
- Applicable to all four standards — The requirements should reflect the inherent differences between different technologies of protection systems.
- Applicable to all four standards — The terms maintenance programs and testing programs should be clearly defined in the glossary. The terms “maintenance” and “testing” are not interchangeable, and the requirements must be clear in their application. Additional terms may also have to be added to the glossary for clarity.
- Applicable to all four standards — The requirements of the existing standards, as stated, support time-based maintenance and testing, and should be expanded to include condition-based and performance-based maintenance and testing. The R1.2 summary of maintenance and testing procedures needs to have some minimum defined sub-requirements to insure that the stated intent of the standards is met to support review by the compliance monitor.

Assessment of PRC-005-1

Purpose

R1.	To ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

A review of PRC-005 indicates that this standard is intended to assure that all affected entities have adequate maintenance and testing programs for their Protection Systems to ensure reliability. SPCTF agrees with the Purpose statement of PRC-005-1.

General Comments

The SPCTF offers the following general comments:

- None of the requirements within PRC-005-1 specifically indicate what minimum attributes should be included in protective system maintenance and testing procedures.
- For interval-based procedures, no allowable maximum interval is prescribed.
- None of the requirements in the existing PRC-005-1 reflect condition-based or performance-based maintenance and testing criteria.

Standard PRC-005 should clarify that two goals are being covered:

- The maintenance portion should have requirements that keep the protection system equipment operating within manufacturers’ design specification throughout the service life.
- The testing portion should have requirements that verify that the functional performance of the protection systems is consistent with the design intent throughout the service life.

Applicability

Applicability 4.3 suggests that the definition of a Protection System in the Glossary of Terms should

> **4.1.** Transmission Owners
>
> **4.2.** Generation Owners
>
> **4.3.** Distribution Providers that owns a transmission Protection System

clarify how a Distribution Provider may be the owner of a transmission Protection System.

Requirements

R1

> **R1.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
>
> **R1.1.** Maintenance and testing intervals and their basis.
>
> **R1.2.** Summary of maintenance and testing procedures.

The following clarifications should be made to Requirement R1:

1. How is the phrase "that affect the reliability of the BES" to be interpreted? The standard should clearly specify which Protection Systems are subject to the requirements.
2. The standard should clearly specify which components of the Generation Protection System are subject to the requirements.

The following clarifications should be made to Subparts R1.1 & R1.2:

1. Interval-based, condition-based, or performance-based maintenance and testing minimum criteria should be established within R1.1, including, but not limited to the following:
    a. For time-based maintenance and testing programs, maximum maintenance intervals should be specified.
    b. For condition-based or performance-based maintenance and testing programs, the program should have sufficient justification and documentation.
2. Definitions should be established for the terms "maintenance programs" and "testing programs."
3. A minimum set of attributes to be included in maintenance and testing programs should be established within R1.2.

R2

> **R2.** Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall provide documentation of its Protection System maintenance and testing program and the implementation of that program to its Regional Reliability Organization on request (within 30 calendar days). The documentation of the program implementation shall include:
>
> **R2.1.** Evidence Protection System devices were maintained and tested within the defined intervals.
>
> **R2.2.** Date each Protection System device was last tested/maintained

The following clarification should be made to requirement R2:

- The appropriate entity should have their Protection System maintenance program and testing program and associated documentation, including maintenance records and testing records, available to its Regional Reliability Organization and NERC during audits or upon request within 30 days.

FERC Assessment of PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0

In the October 20, 2006 Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000), the Federal Energy Regulatory Commission commented on these four standards and proposed changes. The observations and proposals are excerpted from the NOPR and included below.

PRC-005-1

> The Commission proposes to approve PRC-005-1 as mandatory and enforceable. In addition, we propose to direct that NERC develop modifications to the Reliability Standard as discussed below.
>
> Proposed Reliability Standard PRC-005-1 does not specify the criteria to determine the appropriate maintenance intervals, nor do it specify maximum allowable maintenance intervals for the protections systems. The Commission therefore proposes that NERC include a requirement that maintenance and testing of these protection systems 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.
>
> Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC-005-1 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to PRC-005-1 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.

PRC-008-0

The Commission notes that the commenters generally share staff's concern that the proposed Reliability Standard does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protection systems. The Commission agrees and proposes to require NERC to modify the proposed Reliability Standard to include a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval that is appropriate to the type of relay used and the impact on the reliability of the Bulk-Power System.

Accordingly, the Commission proposes to approve Reliability Standard PRC-008-0 as mandatory and enforceable. In addition, the Commission proposes to direct that NERC submit a modification to PRC-008-0 that includes a requirement that maintenance and testing of UFLS programs must be carried out within a maximum allowable interval appropriate to the relay type and the potential impact on the Bulk-Power System.

PRC-011-0

PRC-011-0 does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protections systems. The Commission proposes that NERC include a Requirement that maintenance and testing of these UFLS programs must be carried out within a maximum allowable interval that is appropriate to the type of the relay used and the impact of these UFLS on the reliability of the Bulk-Power System.

The Commission believes that Reliability Standard PRC-011-0 serves an important purpose in requiring transmission owners and distribution providers to implement their UVLS equipment maintenance and testing programs. Further, the proposed Requirements are sufficiently clear and objective to provide guidance for compliance.

Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC-011-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to PRC-011-0 that includes a requirement that maintenance and testing of UVLS programs must be carried out within a maximum allowable interval appropriate to the applicable relay and the impact on the reliability of the Bulk-Power System.

PRC-017-0

PRC-017-0 does not specify the criteria to determine the appropriate maintenance intervals, nor does it specify maximum allowable maintenance intervals for the protections systems. The Commission proposes to require NERC to include a requirement that maintenance and testing of these special protection system programs must be carried out within a maximum allowable interval that is appropriate to the type of relaying used and the impact of these special protection system programs on the reliability of the Bulk-Power System.

Accordingly, giving due weight to the technical expertise of the ERO and with the expectation that the Reliability Standard will accomplish the purpose represented to the Commission by the ERO and that it will improve the reliability of the nation's Bulk-Power System, the Commission proposes to approve Reliability Standard PRC-017-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission proposes to direct that NERC submit a modification to PRC-017-0 that: (1) includes a requirement that maintenance and testing of these special protection system programs must be carried out within a maximum allowable interval that is appropriate to the type of relaying used; and (2) identifies the impact of these special protection system programs on the reliability of the Bulk-Power System.

Other Activities Related to PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0

These four Standards are contained in several projects and draft SARs as part of the "Draft Reliability Standards Development Plan: 2007–2009", which was approved by the NERC Board of Trustees.

The SPCTF recommends that standards PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 be removed from the separate SARS in the Standards Development Plan, and that they be included in a new Standard Authorization Request for a single Protection System maintenance and testing standard.

Conclusions and Recommendations

PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 require additions, clarifications, and definitions to ensure that the Protection Systems are properly maintained and tested.

The SPCTF recommends that standards PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 be removed from the separate SARS in the "Draft Reliability Standards Development Plan: 2007–2009," and that they be included in a new Standard Authorization Request for a single Protection System maintenance and testing standard.

SPCTF submits the attached SAR for that purpose of consolidating PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0 into a single standard to the Planning Committee for endorsement.

Appendix B — NERC SPCTF Supplemental Assessment of FERC Order 893

The following is the main text of the *NERC SPCTF Supplemental Assessment Addressing FERC Order 693 Relative to: 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*, which was approved by the Planning Committee on June 7, 2007, for forwarding to the Standards Committee.

Introduction and Summary

On March 8, 2007, the SPCTF issued a technical review report on Reliability Standard:

- 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*

Within that report, the SPCTF included a summary of the Federal Energy Regulatory Commission's October 20, 2006 Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000). The Federal Energy Regulatory Commission has since promulgated Order 693, in which they approved PRC-005-1 as mandatory and enforceable, and provided specific direction regarding needed changes.

At their March 2007 meeting, the Planning Committee endorsed the SPCTF technical report and an associated Standards Authorization Request (SAR) developed by the SPCTF to modify PRC-005-1 and consolidate the other protection equipment maintenance standards into a single standard. That SAR and the report have been presented to the NERC Standards Committee for consideration, but no action has yet occurred.

This report supplements the observations from the March 8, 2007 technical report on PRC-5, PRC-008, PRC-011, and PRC-017 with FERC's Order 693 determinations regarding those standards.

FERC Order 693 on PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing

In Order 693, FERC presented considerable discussion regarding PRC-005-1. Their discussion completely revolved around the operating-time-horizon issues that were also included in the March 8, 2007 SPCTF assessment of PRC-001-0. These issues were also introduced within the FERC October 20, 2006 Notice of Proposed Rulemaking for adoption of NERC Standards (Docket Number RM06-16-000).

Commission Determination

The following is the determination portion of FERC Order 693 regarding PRC-005-1.

> ¶1475 For the reasons stated in the NOPR, the Commission approves Reliability Standard PRC–005–1 as mandatory and enforceable.

¶1476 In addition, for the reasons discussed in the NOPR, the Commission directs the ERO to develop a modification to PRC–005–1 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. We further direct the ERO to consider FirstEnergy's and ISO–NE's suggestion to combine PRC–005–1, PRC–008–0, PRC–011–0, and PRC–017–0 into a single Reliability Standard through the Reliability Standards development process.

SPCTF Conclusion and Recommendation

SPCTF made similar comments on these and many other issues in its review of the NERC Maintenance Reliability Standards PRC–005–1, PRC–008–0, PRC–011–0, and PRC–017–0, and agrees with FERC's determination. The SPCTF recommends that those changes be made in consolidating the Standards.

FERC Order 693 on PRC-008-0 — Underfrequency Load Shedding Equipment Maintenance Programs

Discussion of PRC-008 in Order 693 included two supporting comments to the Commission's position on testing of UFLS systems (from FirstEnergy and Entergy), and a comment from APPA requesting the ERO to determine whether or not this standard is needed.

Also, the ISO/RTO Council and others commented that the approval and enforcement of PRC-008-0 be linked to the approval of PRC-006-0, which directs the regions to develop and maintain a regional UFLS program requiring specific elements.

Commission Determination

The following is the determination portion of FERC Order 693 regarding PRC-008-0.

¶1491. FirstEnergy and Entergy agree with the Commission's proposed directive, whereas APPA suggests that the need for the proposal should be established first via the Reliability Standards development process.

¶1492. We disagree with ISO/RTO Council and others that approval or enforcement of PRC–008–0 is linked to approval of PRC–006–0. PRC–008–0 requires that a ''transmission provider or distribution provider with a UFLS program (as required by its Regional Reliability Organization) shall have a UFLS equipment and maintenance testing program in place.'' PRC–006–0 requires each regional reliability organization to develop, coordinate and document a UFLS program that includes specified elements. Again, we proposed to neither approve nor remand PRC–006–0 because it applies to a regional reliability organization and the Commission was not persuaded that a regional reliability organization's compliance with a Reliability Standard can be enforced as proposed by NERC. That is not the case with PRC–008–0, which applies to transmission owners and distribution providers. Since PRC–008–0 is an existing Reliability Standard that has been followed on a voluntary basis, transmission owners and distribution providers are aware whether they are required to have a UFLS program in place. We approve PRC–008–0 as mandatory and enforceable because it requires entities to have equipment maintenance and testing of their UFLS programs. As stated in the Common Issues section, a reference to an unapproved Reliability Standard may be considered in an enforcement action, but is not a reason to delay approving and enforcing this Reliability Standard. The Commission expects that the program results will be sent to the Regional Entities (instead of the regional reliability organizations) after they are approved.

¶1493. The Commission approves Reliability Standard PRC–008–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–008–0 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.

SPCTF Conclusion and Recommendation

The SPCTF agrees with the Commission's determination on PRC-008-0. Existing UFLS systems must be maintained regardless of the status of PRC-006; the maintenance & testing of the UFLS is independent of the development of a regional UFLS program or the individual requirements for the program. SPCTF made similar comments on these and many other issues in it March 2007 technical review of NERC Maintenance Reliability Standards PRC–005–1, PRC–008–1, PRC–011–0, and PRC–017–0.

The SPCTF recommends incorporation of FERC's and the SPCTF proposed changes in modifications to PRC-008-0.

FERC Order 693 on PRC-011-0 — UVLS System Maintenance and Testing

Discussion of PRC-011 in Order 693 included two supporting comments to the Commission's position on testing of UVLS systems (from FirstEnergy and Entergy), and a comment from APPA requesting the ERO to determine whether or not this standard is needed.

Commission Determination

The following is the determination portion of FERC Order 693 regarding PRC-011-0.

¶1515. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, we direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process as discussed below.

¶1516. The Commission disagrees with APPA that the decision whether a modification is needed should be established first by the ERO in its Reliability Standards development process. Our direction identifies an appropriate goal necessary to assure the reliable operation of the Bulk-Power System. The details should be developed through the Reliability Standards development process.

¶1517. The Commission believes that the proposal is presently part of the process. The Commission approves Reliability Standard PRC–011–0 as mandatory and enforceable. In addition, the Commission directs the ERO to submit a modification to PRC–011–0 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.

SPCTF Conclusion and Recommendation

The SPCTF agrees with the Commission's determination on PRC-011-0. SPCTF made similar comments on these and many other issues in it review of the NERC Maintenance Reliability Standards PRC–005–1, PRC–008–0, PRC–011–0, and PRC–017–0.

The SPCTF recommends incorporation of FERC's and the SPCTF proposed changes in modifications to PRC-011-0.

FERC Order 693 on PRC-017-0 — Special Protection System Maintenance and Testing

Commission Determination

The following is the determination portion of FERC Order 693 regarding PRC-017-0.

¶1546. The commenters agree with the Commission's proposed directive on a maximum allowable interval for maintenance and testing of protection system equipment and we conclude that such a modification is beneficial. However, we agree with APPA's view on our second proposed directive assuming that the documentation is requested by either the regional reliability organization or NERC. Therefore, we will modify our direction to require that the documentation be routinely provided to the ERO or Regional Entity and not only when it is requested.

¶1547. The Commission approves Reliability Standard PRC–017–0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to PRC–017–0 through the Reliability Standards development process, that includes: (1) a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system and (2) a requirement that documentation identified in Requirement R2 shall be routinely provided to the ERO or Regional Entity.

SPCTF Conclusion and Recommendation

The SPCTF agrees with the Commission's determination on PRC-011-0. SPCTF made similar comments on these and many other issues in it review of the NERC Maintenance Reliability Standards PRC–005–1, PRC–008–0, PRC–011–0, and PRC–017–0.

The SPCTF recommends incorporation of FERC's and the SPCTF proposed changes in modifications to PRC-017-0.

Appendix C – Extended Maintenance Interval Assessment for Microprocessor Relays Based on Markov Modeling

Table 1 in Section 8 allows maximum verification intervals that are extended based on partial or thorough monitoring. The industry has experience with self-monitoring microprocessor relays that leads to the Table 1 value for partial monitoring as explained in Section 8.3. To develop a basis for the maximum interval for thoroughly monitored relays, SPCTF used the methodology of Reference [1], which specifically addresses optimum routine maintenance intervals. The Markov modeling approach of [1] is judged to be valid for the design and typical failure modes of microprocessor relays.

The SPCTF authors ran test cases of the Markov model to calculate two key probability measures:

- Relay Unavailability - the probability that the relay is out of service due to failure or maintenance activity while the power system element to be protected is in service.
- Abnormal Unavailability - the probability that the relay is out of service due to failure or maintenance activity when a fault occurs, leading to failure to operate for the fault.

The parameter in the Markov model that defines self-monitoring capability is ST (for self test). ST = 0 if there is no self-monitoring; ST = 1 for full monitoring. Practical ST values are estimated to range from .75 to .95. The SPCTF simulation runs used constants in the Markov model that were the same as those used in [1] with the following exceptions:

S_n, Normal tripping operations per hour = 21600 (reciprocal of normal fault clearing time of 10 cycles)

S_b, Backup tripping operations per hour = 4320 (reciprocal of backup fault clearing time of 50 cycles)

R_c, Protected component repairs per hour = 0.125 (8 hours to restore the power system).

R_t, Relay routine tests per hour = 0.125 (8 hours to test a protection system)

R_r, Relay repairs per hour = 0.08333 (12 hours to complete a protection system repair after failure)

Experimental runs of the model showed low sensitivity of optimum maintenance interval to these parameter adjustments.

The resulting curves for Relay Unavailability and Abnormal Unavailability versus maintenance interval showed a broad minimum (optimum maintenance interval) in the vicinity of 10 years – the curve is flat, with no significant change in either unavailability value over the range of 9, 10, or 11 years. This was true even for a relay MTBF of 50 years, much lower than MTBF values typically published for these relays. Also, the Markov modeling indicates that the both the relay unavailability and abnormal unavailability actually become higher with more frequent testing. This shows that the time spent on these more frequent tests yields no failure discoveries that approach the negative impact of removing the relays from service and running the tests.

Appendix D — Example of Overlapping the Verification of Protection System Segments

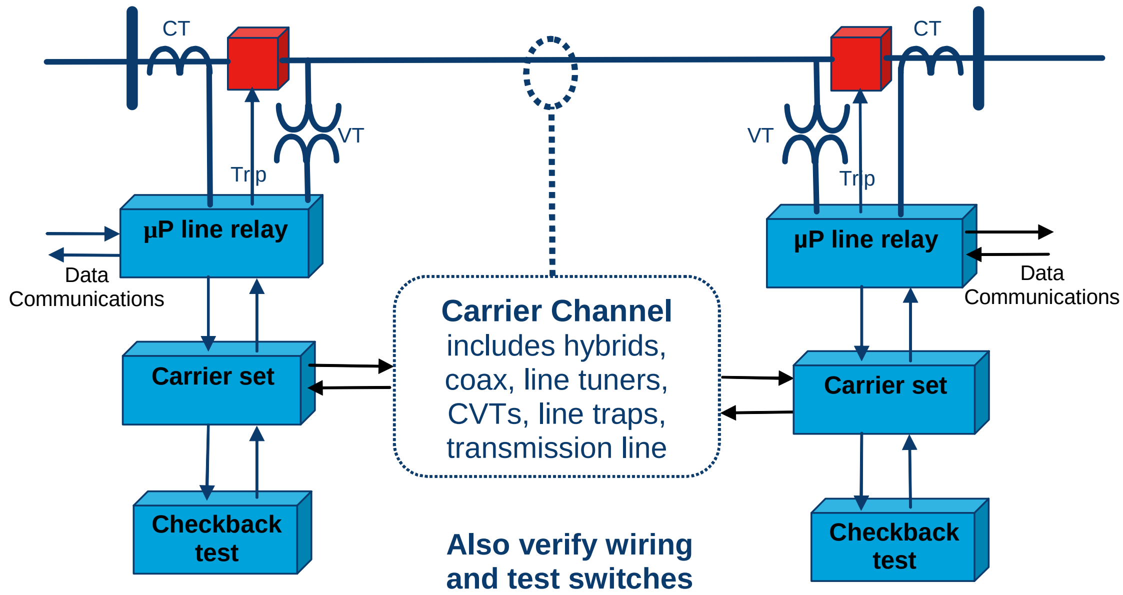

Figure D-1 — Pilot or Unit Transmission Line Protection System Using Power Line Carrier Blocking Channel

The following illustrates the concept of overlapping verifications and tests as summarized in Section 10 of the paper. As an example, Figure D-1 shows protection for a critical transmission line by carrier blocking directional comparison pilot relaying. The goal is to verify the ability of the entire two-terminal pilot protection scheme to protect for line faults, and to avoid over-tripping for faults external to the transmission line zone of protection bounded by the current transformer locations.

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. The relay has a data communications port that can be accessed from remote locations.
2. The relay has internal self-monitoring programs and functions that report failures of internal electronics, via communications messages or alarm contacts to SCADA.
3. The relays report loss of dc power, and the relays themselves or external monitors report the state 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. For maintenance, the user elects to compare these readings to those of other relays, meters, or DFRs. The other readings may be from redundant relaying or measurement systems or they may be derived from values in other protection zones. 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, where they can be compared with other references or state estimator values.

5. Breaker status indication from auxiliary contacts is verified in the same way as in (2). 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 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.

These monitoring activities plus the checkback test comprise automatic verification of all the protection system elements that experience tells us are the most prone to fail. But, does this comprise a complete verification?

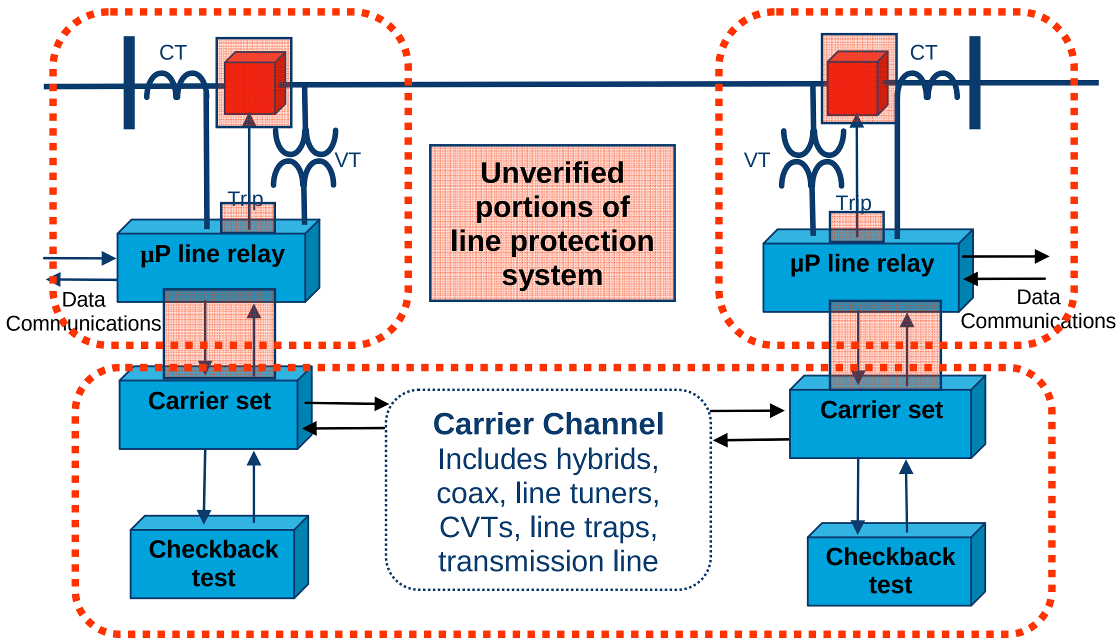

Figure D-2 — Zones of Verification for the Line Protection System of Figure D-1

The dotted boxes of Figure D-2 show the segments of verification defined by the monitoring and verification practices just listed. These segments are not completely overlapping, and the shaded regions show elements that are not verified:

1. The continuity of trip coils is verified, but no means is provided for validating the ability of the circuit breaker to 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. There is no monitoring of the output port, driver circuit, ice cube relay, or contacts of that relay. These components are critical for tripping the circuit breaker for a fault.

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 observe actual breaker tripping, with a specified maximum time interval between trip tests. Clearing of naturally-occurring faults are demonstrations of operation that reset the time interval clock for testing of each breaker tripped in this way. If faults do not occur, manual tripping of the breaker through the relay trip output via data communications to the relay microprocessor meets the requirement for periodic testing.

PRC-005 does not address breaker maintenance, and its protection system test requirements can be met by energizing the trip circuit in a test mode (breaker disconnected) through the relay microprocessor. This can be done via a front-panel button command to the relay logic, or application of a simulated fault with a relay test set. However, utilities have found that breakers often show problems during protection system tests. It is recommended that protection system verification include periodic testing of the actual tripping of connected circuit breakers.

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. If the checkback test sequence were incorporated in the relay logic, the carrier sets and carrier channel are then included in the overlapping segments monitored by the two relays, and the monitoring gap is completely eliminated.

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