Development of Low-Maintenance Protection and Control Systems

1021915

Development of Low-Maintenance Protection and Control Systems

1021915

Technical Update, December 2011

EPRI Project Manager

Y. Lu

ELECTRIC POWER RESEARCH INSTITUTE
3420 Hillview Avenue, Palo Alto, California 94304-1338 ▪ PO Box 10412, Palo Alto, California 94303-0813 ▪ USA
800.313.3774 ▪ 650.855.2121 ▪ askepri@epri.com ▪ www.epri.com

THE FOLLOWING ORGANIZATIONS PREPARED THIS REPORT:

Quanta Technology, LLC

Electric Power Research Institute (EPRI)

This is an EPRI Technical Update report. A Technical Update report is intended as an informal report of continuing research, a meeting, or a topical study. It is not a final EPRI technical report.

NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organizations prepared this report:

Quanta Technology, LLC
Suite 300
4020 Westchase Blvd.
Raleigh, NC 27607

Principal Investigator
E. A. Udren

Electric Power Research Institute
1300 West W.T. Harris Blvd.
Charlotte, NC 28262

Principal Investigator
Y. Lu

This report describes research sponsored by EPRI.

EPRI would like to express its gratitude to all advisors in Protection and Control Task Force for the support and guidance on the project. In addition, EPRI would like thank the following advisors for their active participation and invaluable contribution of this technical update report:

Jim Vespalec	American Transmission Company, United States
Aaron Martin	Bonneville Power Authority, United States
Thomas Roseburg	Bonneville Power Authority, United States
William Winters	Con Edison of New York, United States
Craig Hiemenz	Great River Energy, United States
Paul Difilippo	Hydro One Networks, Canada
Mohammad Zubair	Hydro One Networks, Canada
Ray Zhang	National Grid, United Kingdom
Michael Cooper	National Grid, United States
Alex Echeverria	New York Power Authority, United States
Frank Ronci	New York Power Authority, United States
Daniel Zhang	New York Power Authority, United States
Ted Warren	Southern Company, United States

This publication is a corporate document that should be cited in the literature in the following manner:

Development of Low-Maintenance Protection and Control Systems. EPRI, Palo Alto, CA: 2011. 1021915.

ABSTRACT

Protection and control (P&C) system maintenance is a critical task and requirement for the reliability of power grid. Traditionally, electro-mechanic devices require regular calibration and maintenance for proper operations. Thus, time-based maintenance programs have been developed by utilities and have not changed much even after the industry migrated to the microprocessor and communication-based digital protection technologies.

The Electric Power Research Institute (EPRI) Protection and Control Task Force has undertaken a research initiative in 2011 for development of new P&C maintenance practices. The goal of this project is to research feasible approaches and technologies for reducing the cost of maintaining protection systems or need of human intervention, while keeping or even improving reliability and performance of protective relaying systems. The core approach is to take advantage of the self-condition monitoring methods and alarming of failures built into modern P&C equipment and systems. Condition monitoring can be implemented within existing components of a protection system or can be achieved by the specific connection and application of those components in a proper system design.

A large population of electromechanical protection still remains in service but is already close to the end of its life cycle. While utilities are embarking on major replacement programs, it could be a good opportunity for these to-be-built protection systems to take advantage of new maintenance approaches and designs being developed in this project.

Designing P&C systems that support low-maintenance attention and yet maintain high protection reliability requires investigation of exactly how the elements of the system operate interactively. Gaps and shortcomings in self-monitoring must be identified and remediated. The EPRI project, over its planned years of execution, will research and develop suggested design approaches and functional specifications to achieve the stated benefits and also support documentation of maintenance practices.

The project will conduct industry surveys to understand the state of the art of condition monitoring for P&C systems and will identify the technical gaps or limits.

This report gives an initial technical overview of protection system components and monitoring opportunities, especially for protective relays and communications systems on which the work is focusing. It reports the results of a survey of EPRI member utilities on maintenance practices and experiences. It reviews the status of development of North American Electric Reliability Corporation (NERC) Protection System Maintenance Standard PRC-005-2, whose requirements will be considered in developing the new low-maintenance designs or practices. The report concludes with a roadmap for project research and development work in 2012 and 2013.

Keywords

Condition-based maintenance (CBM)
Maintenance
Protection system
Relay
Survey

CONTENTS

LIST OF FIGURES

1
INTRODUCTION AND BACKGROUND

Maintenance of Protective Relaying Systems

Protective relaying is critical to reliable operation of all sections of the electric power system. Relaying systems are the watchful monitors of all apparatus and zones, initiating tripping of circuit breakers within milliseconds of a power system fault or malfunction to avoid widespread system collapse, to enable rapid restoration, and to protect expensive primary power equipment from damage.

Generations of electromechanical and analog solid state relays have required periodic testing to detect failures or calibration drift which produce no external symptoms. Malfunctioning protection system components may lead to delayed fault clearing, failure to clear faults, or undesired tripping and system fragmentation for faults not in the zone of protection for the relay that operated. Utilities have thus developed time-based maintenance programs with testing activities and time intervals based on their experience with failure rates of relays or guidelines mandated by power system reliability entities.

Utilities invest significant capital and operating resources to equip maintenance technicians, run protection system maintenance programs across the entire range of protection systems, manage testing program performance data with IT systems, and train personnel. A large utility may own 10,000 to 50,000 relays, not counting the other components of a complete protection system.

Since 2007, utilities have faced a step increase in the costs of protection system maintenance programs, as they work to meet North American reliability standards for the Bulk Electric System (BES) written and audited by regulation entities.

Objectives of the EPRI Project

The goal of the present project, begun in 2011, is to research new approaches and technologies for reducing the cost of maintaining protection systems, while keeping or even improving reliability and performance of protective relaying systems. Existing time-based maintenance practices have not changed much since the electromechanical protection era. These practices are not a good fit for modern microprocessor-based protection and control systems.

At this moment in history, a large population of electromechanical protection remains in service, as utilities are embarking on major replacement programs. Are the new protection system designs taking advantage of new maintenance approaches? It is a critical time for the industry to review the existing maintenance practices and find a better way to achieve reliable protection performance of the microprocessor-based digital P&C infrastructure. In addition, since documentation of the maintenance program and its performance has become a significant request, a related goal is to explore the possibility of simplifying, automating, or reducing documentation of maintenance approach and activities.

New generations of protective relaying offer noteworthy ability to monitor their own performance, as well as that of surrounding connected components and systems. This brings the potential for reduction or complete elimination of periodic maintenance on most components of a protection system. Just replacing electromechanical or solid-state analog relays with microprocessor designs can bring some benefit of self-monitoring. However, designing P&C systems which support low maintenance attention and yet maintain high protection reliability requires a deeper investigation of exactly how the elements of the system operate interactively. Gaps and shortcomings in self-monitoring must be identified and remediated. The EPRI project, over its planned years of execution, will research and develop enabling technologies, suggested design approaches and functional specifications to achieve the stated benefits, and also support proper documentation of maintenance practices. It will identify opportunities for manufacturers of relays and protection system components to help users with documentation components describing features of their products; it will also indentify opportunities for design improvements in the monitoring capabilities of products.

As a central feature, the project includes seminar-based sharing among and education of EPRI Task Force members on technical issues and opportunities in protection system maintenance as the work proceeds. This includes survey of member practices, collaborative development of technical approaches to meet practical needs of members, and information sharing on latest reliability standards development that can directly impact protection system maintenance and design practices.

Relationship to reliability standards

Although the project includes discussion of reliability standards, such as NERC (North American Electric Reliability Corporation) Protection System Maintenance standards PRC-005-1 (presently mandatory and enforceable) and PRC-005-2 (under development, and supportive of low-maintenance strategies), it is not intended to provide direct or specific guidance to EPRI members dealing with NERC compliance or auditing. Rather, the research project will study these standards as they impact the industry environment in which the low maintenance approaches are being developed in this project. The members will each maintain their own individual responsibility for creating company approaches or programs to meet reliability standards compliance.

In general, reliability standards apply to the Bulk Electric System (BES). As of the date of this report was written, distribution, load serving sub-transmission, and some radial facilities are not part of the BES, therefore not subject to the standards. However, utilities still need to maintain non-BES protection systems to insure excellent customer service metrics based on outage frequency and duration, and to minimize damage or hazards caused by protection failures. The project outcomes aims to offer technical guidance that utilities can apply to sub-transmission and distribution protection systems, in order to reduce or eliminate preventive maintenance testing on those systems, even though there is no regulatory focus.

Project Steps in 2011

The first phase of work comprises:

- Presentation of the concepts for developing low maintenance P&C systems to EPRI Task Force members in multiple teleconferences.
- Interactive discussion and presentation at the EPRI Task Force meeting held in August at Consolidated Edison Company in New York.
- Preparation of a questionnaire to survey existing P&C maintenance practices and issues. The survey is to gather critical background information to support research approaches and business case development.
- Interviews of multiple EPRI utilities to gather survey responses.
- Summary of survey results received so far, analysis of the results, and proposal for project directions going forward.
- Roadmap for achieving project goals.
- Update the P&C task force on the latest developments on the new NERC PRC-005-2 Protection System Maintenance Standard

Documentation of results is contained in following chapters of the present report.

2 DEFINITIONS AND TECHNICAL DRIVERS

Protection System Definition and Scope of EPRI Project

Relays are just one element of a complete protection system. The NERC Glossary (see http://www.nerc.com/files/Glossary_of_Terms_2011August4.pdf) defines *Protection System* as comprising:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions,
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

In this EPRI report and project, use of the capitalized term Protection System refers specifically to the array of components as defined in the NERC Glossary.

While EPRI supports research work for maintenance of all of these components, the present project will focus on the first two bullets – protective relays, and communications systems. It is not possible to look at gapless monitoring of the Protection System without analyzing signal sources and interconnections, but these will be treated only in the Protection System context.

Note that EPRI carries out research in other task forces on maintenance of the battery as part of the station dc supply system, and on maintenance issues of circuit breakers. Accordingly, detailed consideration of maintenance procedures for these parts is currently conducted in other EPRI projects and Task Forces.

Circuit breakers

It is important to note that as of the date of this report is written, the NERC definition of Protection System does not include the power circuit breaker that actually interrupts fault current. There is no NERC maintenance requirement for circuit breakers; although they are in fact complex mechanical systems requiring maintenance and testing that most utilities perform vigorously. Meanwhile, EPRI substations program has a number of task forces and research projects working on the subjects and help utilities understand breaker reliability issues and effective maintenance procedures.

The protection system *does* explicitly include the breaker trip coil in its control circuitry. The e electrical continuity and connection of a trip coil can be monitored continuously. However, it is not possible to know that energizing the trip coil will actually produce trip of a breaker operating mechanism, even if it is shown to be continuous before the trip signal is applied. So fully testing a trip coil ultimately requires tripping the breaker.

The current report will point out where relays and communications systems interface to breaker trip coils and consider monitoring opportunities for Protection System maintenance reduction, but major R&D work on circuit breaker maintenance or condition monitoring opportunities is being conducted in the other EPRI research projects and task forces.

While NERC's exclusion of complete breakers from maintenance requirements may seem illogical, breaker failures are in fact seen as unavoidable in the real world. Accordingly, NERC transmission planning (TPL) standards require that failure of a circuit breaker to trip does not lead to a cascading outage under any conditions. This leads the utility to run breaker failure contingencies in planning studies, and to design the transmission system for survival by any combination of remote backup protection, local breaker failure protection, robustness of the surrounding transmission grid, and operating restrictions.

Protection System failures and redundancy

Of course, transmission protection systems can also fail; this possibility is also reflected in power system planning standards as for breaker failures. Isolated dual redundancy of protection systems is a widely used solution to the power system performance impact of a single protection system failure to trip, if time-delayed remote backup protection tripping is to slow or too disruptive to prevent a cascading outage. The NERC System Protection and Control Subcommittee (SPCS) has proposed a in a Technical Reference an approach to a standard for redundant protection – see http://www.nerc.com/docs/pc/spctf/Redundancy_Tech_Ref_1-14-09.pdf. This document discusses criteria for determining when or where dual redundant protection is required, and gives specific requirements for the redundancy design if used.

Classification of Protection System Maintenance Programs

Time Based Maintenance (TBM)

Time Based Maintenance (TBM) describes testing on a periodic time schedule, as the industry has done since its inception with electromechanical and analog solid state relays. Prescribed maximum maintenance or testing intervals are applied for component types or groups of components. The intervals may have been developed from prior experience, from manufacturers' recommendations, or from requirements of a regional reliability organization (RRO). 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. This is sometimes called natural testing. A few utilities have strong programs to gather operating data from every fault and study for evidence of protection system performance, but the majority focus on studying records only when there is an apparent misoperation or defective operation.

Condition Based Maintenance (CBM)

CBM is a program based on equipment which observes its own integrity and performance in service - it is actually monitoring or testing itself as it performs its protection job, and alarming for failures. Continuously reported results from non-disruptive self monitoring show operational status – CBM achieves verification that is as good as or better than that of TBM testing. The owner performs no maintenance until the self-monitoring component reports a failure.

Performance Based Maintenance (PBM)

PBM is a special case of TBM in which the 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 a high failure rate, more frequent maintenance (or remediation of the root cause of these failures) is required. If the group shows documented very low failure rate in TBM tests, the maintenance interval is extended as much as possible while keeping an acceptably low failure rate. Even after time intervals for the group have been extended, some low rate of TBM must be maintained for the group to justify continued use of extended PBM intervals, and to discover any increase in failure rates requiring remediation or more frequent testing.

Relationship of Maintenance Types

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. In CBM, self-monitoring processes are still effectively testing components, with repeated nondisruptive validations whose time intervals can be hours or even milliseconds, as components remain in service.

TBM, PBM, and CBM can be combined for individual components, or within a complete Protection System, to get the most effective and complete overall result.

Self Monitoring by Microprocessor Relays and Data Communications Systems

Modern protective relaying and substation control systems, based on microprocessors and data communications, are capable of monitoring the majority of internal components and alarming for failures. A substantial portion of utilities have had one to two decades of favorable experience with these monitoring capabilities. This experience, combined with the observation that microprocessor relays do not drift or require calibration, has led to widespread lengthening of maintenance test intervals for these types of relays as compared to their electromechanical and analog solid state forbears. As explained in this report, a major portion of microprocessor relay electronic hardware can report its failures, and periodic maintenance testing of this hardware brings no further benefits – it may in fact be a liability as discussed below.

Furthermore, modern networked protective relay and substation IED data communications architectures using a variety of formats or protocols provide new tools for monitoring integrity and performance of connections among communicating devices, and correct operation of functions using the communications. Any data communications path with a heartbeat of routine message exchange can be monitored by the microprocessors at both or all communications connections, alarming for any degradation or failure of expected information exchange. As is true for much of the relay hardware, there is no further benefit from removing the channel from service to perform maintenance tests when the channel is reporting healthy performance.

In spite of the benefits of self monitoring, there are still technical gaps or omissions in the completeness of coverage for functional monitoring of the protection system overall. Accordingly, utilities still carry out significant periodic testing on protection systems. A section appearing later in this chapter discusses an example of a protection system with significant monitoring, showing gaps in coverage, and hinting at strategies for closing some gaps. A major objective of the EPRI project with its multi-year roadmap is to more comprehensively identify gaps for a broad range of system designs and component types, with design techniques or choices for reducing or closing those gaps that can be closed. All of transmission, distribution, and generation are to be considered.

Benefits of Monitoring

This report and project look at the economic benefit of a maintenance program based on monitoring and alarming – condition based maintenance (CBM) - as an alternative to time based maintenance (TBM) testing of components by technicians. We state for now that designing with a system approach to CBM building on the features already included in modern relays and protection system components has the ability to eliminate most human TBM activity, and the costs of that activity. But this may not be the most important benefit.

Benefits of CBM:

1. Immediate exposure and alarming of failures, enabling system operating remediation during stressed conditions, and the most rapid possible repair. With TBM, a component may fail immediately after a scheduled test. The failure is hidden and will not be revealed until misoperation for a fault shows that repair attention was needed.
2. Elimination of human intervention in protection system components that don’t need attention. Maintenance errors are a significant and documented cause of misoperations. There are notable cases of relays and components left in a non-operating state after maintenance testing – settings modified and not returned to correct values, test switches not restored to operating position, concealed mechanical or electrical damage to tested or adjusted components.
3. Substantial savings from avoided testing time, travel time, materials, any operating cost of providing testing outages, and some portion of capital testing equipment cost.
4. Consistent implementation of maintenance monitoring in every protection system designed according to a standard CBM scheme.
5. Reduced gathering and accumulation of test records.
6. Improved ability to focus on Pareto of failure causes, remediate bad-actor components and designs, and manage overall performance and reliability of protection systems.

Drawbacks and Risks of Relying on Monitoring

The investigators believe the benefits to be already accepted and proven, but it is important to think of CBM *risks* that implementers should confront:

1. Routine and repeated TBM gives technicians a high degree of skill and comfort in working on protection system components. Removing this TBM from their work routine means that when they are dispatched to repair alarmed failures, they may be less sure of how to perform the repair, and repair errors or repair time may increase. Managing this significant risk is discussed by itself just below.
2. The scheme designer must be aware of what specific items are not monitored, yet whose failure could impact fault protection. This will require auxiliary monitoring design, or will remain as a residue of TBM activity.
3. The scheme designer must also identify unmonitored items that could cause problems *other* than failure of protective relaying. Users and manufacturers may not have developed as clear a picture of what these items could be. An example, not considered to be a real concern but not investigated for this report, is the synchronization of waveform sampling with the GPS input – a failure would result in publication of synchrophasor streams whose angular values are out of specification and could confuse a WAMS or WAMPAC implementation. Can the relay detect and alarm problematic non-relaying problems? The present EPRI project will consider these topics as the work proceeds.
4. There have been cases of product design issues resulting in a failure that should have been alarmed, but was not alarmed. For example, there were certain relays whose protection processing would cease without producing dropout of the watchdog alarm relay. Manufacturers found and fixed this problem, and have designed its root cause out of products. Fortunately, such problems are exceptional and rare.

   It simply is not possible to guarantee that no such hidden monitoring problem will ever occur in a future product. However, as with any technical evolution, a bad experience leads to new designs and design standards that reduce this risk. The assessment of the EPRI investigators is that the risk is insignificant, especially in comparison to other TBM risks mitigated by the use of CBM. But a designer is always justified in maintaining the focus of manufacturers by asking them how they assure that new products are free of such issues.

Maintaining skills of maintenance technicians

The EPRI investigators have seen from industry experience that the way to manage Risk (1) just above is to build one or more laboratory models of a new protection system design as it is being developed. Laboratory panels are useful for debugging the original design, confirming its CBM features, and preparing it for field commissioning. However, such laboratory systems play multiple crucial roles after the new design is deployed in the field, and must be constantly have its hardware and firmware updated to track changes in the field installations.

An optimum laboratory facility includes sources of steady state and fault ac signals from test sets or power system simulators, and simulations of circuit breakers and other primary power apparatus.

Uses of the laboratory include:

1. Development and testing of relay, communications, and IED programming.
2. Validating design for CBM alarming and repair capabilities by introduction of failures.
3. Engineering development and maintenance team vetting of physical and mechanical design features for safe maintenance including panel layout, displays, indicators, controls, and marking for maintenance error avoidance.
4. Developing wiring and networking configuration for component repair and replacement while the protected primary equipment is in service.
5. Documenting monitoring and maintenance program support information gathering – ability to gather performance management metrics.
6. Training and drill of technicians on operating and maintenance procedures.
7. Replay of field events, including operator actions, for rapid post-mortem analysis of behavior.
8. Trying out unanticipated repair techniques or sequences in the lab before trying them on field installation – arrive at the substation with the proper steps, equipment, and tools.
9. Testing the integration and interoperability of new products, and firmware or hardware revisions to existing products before they are approved for use in working substations. Trials of upgrades and changes to systems in service, including relay vendor firmware upgrades in a system environment.
10. Testing of SCADA/EMS features, and correct operational and/or non-operational interfacing to the enterprise. This is most effective when the laboratory model is connected to live control centers and enterprise systems as a dummy location whose behavior can be remotely observed.
11. Presentations to company management and to visitors.

With a CBM program, the nature of technician training and skill development changes from familiarity through repetition to simulator focused training. This training is like that widely used for system or power plant operators, who are not permitted to damage equipment or impose blackouts in order to learn what to do and what to avoid.

Monitoring Technologies and Capabilities in Specific Relays

Electromechanical relays

In general, any device with a mechanical component that must move for fault protection, but is not moving routinely and observably the rest of the time, can develop a hidden mechanical problem and must be tested. These mechanical assemblies are usually designed so that they don't move frequently during non-fault times, and long idle times degrades their reliability, or at best does not help with assurance of their ability to operate when needed.

Prime examples are lockout switches, clapper-type auxiliary relays, and small ice-cube sized output relays mounted on the circuit boards of relays or components otherwise using electronics.

A strategy which could prove helpful in certain applications is to consider whether there is some way to periodically operate such a device within a larger scheme where its operation can be observed yet it is not producing a trip. Such a monitoring scheme must itself not introduce other unmonitored parts that could actually degrade the reliability of a simple and reliable unmonitored design. Such an approach, if promising, will be presented in later work.

It is only partially helpful to observe operation of electromechanical measuring relays that move in cases where there is no trip decision. For example, the 21P or 21NP trip relay and the 21S or 21NS blocking relay in an electromechanical blocking carrier line protection scheme both pick up for faults outside the zone of protection when the scheme overall does not trip. Digital Fault recorder (DFR) or oscillograph connections may show such operations. We noted that some utilities gather and study these records, and may find failures and problems. But for calibrated measuring elements, the observed operations do not show correct calibration. So some TBM calibration test will still be required.

Analog solid state relays

These relays and components have electronic measuring or operating circuits based on active electronic devices (transistors, operational amplifiers, gate logic devices) in combination with electromagnetic or passive components (resistors, capacitors, inductors, transformers). Multiple individual circuits are logically combined for fault protection decisions. When a specific component fails, the result could be a false trip, failure to trip, or loss of calibration. The latter two failure types are generally hidden as for electromechanical relays, and can be found only by test. Vulnerable sections of these devices may be monitored, but in general the whole relay or component is not monitored.

Note the existence of hybrid relays or communications devices with microprocessor logic fed by analog measuring circuits. Even though the microprocessor part may monitor itself as described next, the critical analog parts remain vulnerable, and require periodic testing of the overall unit that validates each of analog sections.

We further note that some of the most advanced hybrid relays that preceded the early generations of microprocessor relays included a built-in periodic test that automatically switched the analog inputs from power system to internal test source values, blocked trip outputs, and self-checked for correct responses. It would require technical investigation to determine if this periodic internal test really validates all components, and whether the testing and switching circuits themselves introduce failure vulnerabilities. For example, can the relay become locked in test mode, unable to protect, without an alarm? The approach in the NERC maintenance standard PRC-005-2 under development is simply to require periodic testing of such a relay.

Microprocessor relays

Microprocessor relays include comprehensive monitoring that can be used to reduce or eliminate TBM. They can monitor many connected paths and devices external to the relay itself. Some gaps remain, many or most of which can be closed by system design and programming. Closing these gaps is the subject of upcoming project work.

The definition of a microprocessor relay developed by the author of this report and used in the new NERC maintenance standard is a relay with the following features:

- 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.
- Internal self diagnosis and alarming.
- Alarming for power supply failure.

The first bullet requirement has been crafted to include first generation full microprocessor relays from the late 1980's and early 1990's, as well as all successive evolution of this line of products. Examples of widely used first generation products are the Schweitzer Engineering Laboratories© SEL-121 (4 samples per cycle), Westinghouse© or ABB© MDAR (8 samples per cycle), and General Electric© DLP (12 samples per cycle). It excludes all analog solid state and hybrid relays described in the previous subsection.

Monitoring capabilities

The second and third bullets refer to the fact that after the measurement data has been sampled and converted to numeric and digital format, the processing system is readily designed to insert performance integrity monitoring checks in a way that does not impair or disturb the primary protective relaying functionality. Monitoring functions may include:

1. Multiple processors, data buses, peripheral parts communicate constantly & check for failures.
2. Data communications of processors with memory and peripheral devices over data buses and links.
3. Data communications among multiple processors and DSPs in a newer relay design.
4. Rolling checks of every storage location in a data memory device.
5. Checksum validation of the integrity of contents of a program or setting memory.
6. A/D converter calibration and zero checks.
7. Power supply or catastrophic internal failure – failsafe (normally closed) watchdog alarm.
8. Dc supply voltage or internal electronic supply voltage checks.
9. Relay logic checks consistency of ac measurements
10. Relay logic checks consistency of binary state reports from connected power apparatus.
11. Data communications failure – streaming or heartbeat traffic ceases.
12. Monitoring of continuity of trip circuit (TCM) via voltage across trip contacts.
13. Trip indication current monitor in series with trip circuit – can validate trip output operation via trip current flow.

Note that features 9 through 12 comprise cases of the relay intelligence reaching outside of its own box to validate the condition of external components on which protection depends.

Since all relays beyond the first generations possess increasingly sophisticated programmable logic and measurement capability, we can add programming that further enhances or completes the monitoring of external connections and components.

Monitoring gaps

The most obvious monitoring gaps exist for the binary inputs and outputs which are not routinely changing state. The inputs comprise optical isolators, debounce timing, state decision logic, and input ports of the microprocessor system. Contact outputs comprise electromechanical ice-cube relays driven by normally-unchanging microprocessor output ports and driver electronics. These quiescent components are all capable of failing without an indication or alarm, unless we engineer additional monitoring schemes for them. The component most frequently observed to fail is the trip relay, whose contacts are not visible, and may be damaged by slow tripping or stuck circuit breakers.

Relay manufacturers offer optional solid state trip outputs which speed up tripping, and which are resistant to contact damage because they have no contacts and can cut off persistent trip coil current to a malfunctioning breaker. The industry had painful false trip experience with thyristor-based solid state trip outputs in the 1970s and has been hesitant to adopt solid state trip outputs, even though the electronic technology has migrated to MOSFETs and does not have the old vulnerability. But these new solid state outputs still use quiescent drivers and are not inherently monitored.

Early microprocessor relays sampling at 4 per cycle used low cutoff frequency input anti-aliasing filters that had strong attenuation at 120 Hz, and unavoidably introduced noticeable phase shift at 60 Hz. The filters used film capacitors which, while reliable, could show drift of capacitance over many years of service. This could impact the behavior of distance relay characteristics computed from voltages and currents whose phase shifts were not consistent. The result is a characteristic drift rather than failure – mostly a problem only where reach settings are critical. This drift behavior is not monitored in the relay, although comparing metered values with an external accurate reference might reveal the drift. Many of these relays have been retired for other reasons and replaced with newer units having higher sampling rates and higher-cutoff anti-aliasing filters whose drift doesn’t affect power frequency behavior.

A central theme of the EPRI project is to combine overall system design with programming to monitor the entire system in a way that closes gaps, detects problems as well as or better than a time-based maintenance test, and does so as soon as the problem arises.

Monitoring Technologies and Capabilities in Specific Communications Systems

Power line carrier systems

For power line carrier communications used in pilot protection of transmission lines, some functional and performance monitoring is typically included today. Monitoring gaps remain, which are judged by the investigators to be possible to close, as explained below and as explored in project work to come.

On-off carrier

On-off carrier sets used in blocking schemes are silent until a fault occurs behind the terminal whose carrier transmission is under consideration. Due to the relatively high probability of degradation or failure of channel components, these channels have for many decades been monitored by frequent periodic manual keying, or by an automatic checkback test that runs from one to four times a day. The checkback test was formerly provided by an external pair or group of test units connected to the two or more carrier terminals. Newer carrier sets incorporate the checkback test function within the carrier transceiver set.

Furthermore, the test can detect serious degradation in a carrier channel that is still functioning by transmitting the test carrier signal at a lower level (e.g. 10 db transmitted power reduction) than is used for an actual blocking signal.

Frequency shift keyed (FSK) carrier

Unblocking pilot line protection schemes and carrier based transfer tripping use a frequency-shift carrier in which a signal at a guard or monitoring frequency is sent continuously. Loss of guard signal is alarmed, and guard loss is used in protection logic to minimize the chance of misoperation when the carrier channel is lost (as can happen at the moment of an internal fault on the protected line). To send an unblocking signal (allows pilot trip) or transfer trip signal to the other line terminal, the frequency of the continuous carrier is shifted from guard frequency to trip frequency. The transmitted power may also be boosted while trip is sent, so that the guard signal is sent at a lower level to monitor channel performance continuously.

Analog voiceband channels – telephone circuit or microwave

These paths are used for line protection (direct or permissive transfer tripping) and for direct transfer tripping independent of line protection logic. They are subject to failures – microwave paths can fade, and leased telephone circuits are often disabled or interfered with by telecommunications technicians not employed by the electric utility and not trained in the risks of careless maintenance actions.

Historically, signaling has been carried out with an audio tone set comprising one or two FSK audio signals – reception of the guard frequency (or two guard frequencies) monitors that the channel is in service. Loss of guard alarms an outage. However, the audio tone channel may be spoofed into false tripping by inadvertent connection of test signal generators, or by frequency shift disturbances in trunk analog multiplexer modulation systems. Certain design features of a dual frequency FSK audio tone set can minimize this false trip risk. In summary, these obsolescent analog FSK audio tone systems have useful monitoring capability, developed through painful experience of misoperations.

A modern pilot teleprotection set for an analog voice circuit is a modem that transmits repeated binary data messages in both directions between terminals. The specificity of the data messages is such that the risk of false trips from interfering analog signals is eliminated. The constant exchange of messages representing quiescent states monitors the channel for performance and alarms for failures. The teleprotection set can transfer a whole group of binary state changes – from 4 to 16 – so many functions can be carried by one channel and pair of sets (e.g. pilot protection of a line, direct transfer trip, multiple auxiliary controls). The overall channel facility and its terminal equipment is monitored, but note that a single failure can disable all functions operating over that set, so the multiple signals do not provide redundancy against failure.

Monitoring gaps – carrier and analog voiceband channels

All of these channel types communicate with the relays they support via binary I/O points that are unmonitored as for relays, and could benefit from through-system monitoring design as discussed below and in upcoming project work.

There is at least one recent carrier channel set product which is capable of communicating with its associated relays by IEC 61850 GOOSE messaging. This relaying information passes directly between the processor of the relay and that of the carrier set via a fully monitored Ethernet path as explained below, completely closing the monitoring gap between the relay and the carrier set that exists when binary I/O is used for relay-to-carrier status exchange.

Carrier channels have one persistent vulnerability for which any monitoring will prove difficult, and is declared out of scope pending further discussions. Protective air gaps in line tuners and on capacitive voltage transformer drain coils may become contaminated by dirt or spider webs. The insulation level may be adequate for normal carrier isolation, but the gap may break down at lower than rated voltage for transients. During a breakdown discharge, the carrier signal is shorted or may show holes (brief millisecond interruptions). There is no guaranteed effective monitoring technique, and sophisticated monitoring would be needed to give even a chance of catching this problem by observing signals over time. It continues to be necessary for users to periodically inspect these gaps in switchyard equipment. Some utilities have replaced air gaps with gas discharge tubes whose performance is less vulnerable to contamination, but discharge tubes can only maintain performance until they have mitigated a specified total amount of discharge energy over time. So gas tube inspection and replacement may still be required, although specified insulation performance over a reasonable time window is more predictable and not vulnerable to random compromise like an air gap that becomes home for a spider.

Data channels

This category of protective relaying channels includes all communications paths over which data messages pass from one self-monitoring microprocessor system to another. The two systems may be one relay communicating with another on the same panel, or the relays may be communicating over long distances between stations.

Such a communications exchange can be inherently self monitoring if two criteria are met:

- The data messages are sent periodically – with a heartbeat – regardless of whether or not any particular action or information is being exchanged. In other words, there is constant message exchange, and only message *content* changes between quiescent and active situations. Thus, loss of messaging can be quickly noticed by the receiving processor, which can attempt to notify the sender and can alarm the failure for repair.

- The data messages are sent in structures or with added information to support detection of data errors, loss of messages or information, or latency or timing problems. These detection capabilities support alarming for failures more subtle than total channel loss, and are used to report degradation of a channel as it continues to perform its function.

Channels between monitored relays that meet both criteria create a zone that comprises both relays and the full communications path all taken together as one gapless, fully monitored entity not requiring TBM for the core pilot relaying functionality. Where more than two relays exchange messages over a multidrop network, the entire network of devices can become a unified self monitoring entity.

Examples of such channels include:

1. Proprietary current differential relaying values and status between relays over serial path – dedicated optical fiber, or IEEE C37.94 interface to TDM data trunk facility like T1 over SONET or digital microwave.
2. Proprietary control protocols with a heartbeat of exchanges, such as SEL© Mirrored Bits© or GE© Direct I/O©, operating over serial or Ethernet network.
3. Proprietary control protocols as in item (2), operating over interstation path as in (1), for directional comparison protective relaying or for transfer tripping.
4. DNP3, Telegyr, or any other SCADA protocol with periodic polling, over serial or Ethernet channel, among IEDs in a substation or between substation and control center.
5. IEC 61850-8-1 GOOSE messages for binary status, control, or analog values – Ethernet within the substation or over interstation connections as described in TR IEC 61850-90-1.
6. IEC 61850-9-2 sampled values messages for streaming switchyard raw data samples - Ethernet within substation.
7. IEC 61850 client-server exchanges configured for polling (not report-by-exception) – Ethernet within substation (substation to control center exchange under development).
8. IEEE C37.118 or 118.2 streaming synchrophasor messages to phasor data concentrator (PDC) or client – serial or Ethernet, within substation or between sites.
9. IEC 61850-90-5 streaming synchrophasor, network GOOSE, or network sampled values – Ethernet within substation or via wide area network (WAN).

Functional Versus Performance Monitoring

For all of these channels, we will distinguish between *functional* monitoring and *performance* monitoring. Channel performance can and often does degrade gradually, without causing the channel to cease providing its correct function, until the performance reaches a threshold level of unsuitability. While functional monitoring (observing that the channel is communicating and able to transfer states or information) is critically important, we cannot consider eliminating TBM unless the channel *performance* is monitored. Performance monitoring looks at quantities that show degradation - received signal level, consistency of received signal level, out of band noise or signal level, and standing wave ratio or output power at transmission line connection (carrier or radio systems). For data channels, performance metrics might include signal or light level, bit error rate, lost packet or lost message rate, excessive latency, losses of synchronization, incorrect message source identification, or detection of specific message issues (GOOSE packets out of order or aged beyond Time To Live parameter).

Relays and IEDs that are capable of exchanging data messages are generally also capable of alarming and reporting performance degradations, supporting development of thoroughly monitored TBM free designs.

Voltage and Current Signals Required for Protection

While instrument transformers (ITs) are not included in the scope of the EPRI program, the accuracy of the signals they produce are obviously critical to relaying. We must define methods to monitor their presence and accuracy, or else TBM testing of ac inputs to every relay will still be required. This project does not engage the topic of maintaining the instrument transformer itself, but we must use the monitoring facilities of protective relays and their associated communications to monitor the integrity of these signals.

There are four major categories of practical issues seen (or not seen) in service:

1. Correct calibration of voltage and current signals, considering both magnitude and phase angle. Values could be corrupted by shorted turns in transformers (instrument transformers, or isolating transformers inside the relay), wiring problems, or uncommon electronic failures in the relay front end filtering and A/D conversion subsystems. The easiest way to validate ac input accuracy is to compare the readings from two different relays or other measuring systems looking at the same power system values, preferably through other instrument transformers or circuits (if ITs are to be validated along with the rest of the ac input circuits).
   - Easiest is to compare readings of two redundant relays fed from different CTs and different VTs or VT secondary circuits on the same primary circuit.
   - An alternative is to measure values at opposite ends of a line or zone, considering line drops and shunt capacitance where the effect is noticeable. This calls for care in evaluation of phase angles or sign of real and reactive power flows.
   - Voltages around a bus or node are consistent, and currents should add up to nearly zero if there is no problem.
   - Power transformer effects (phase shifts, taps, small losses) can be accounted for to compute useful comparisons in most cases. But monitoring this way brings tap changers into the circle of components whose correct performance is being monitored as a unit.
   - Comparisons can be made in the substation, perhaps by a data concentrator, or all values can be sent to the control center via SCADA

2. Detection of inadvertent rewiring errors in instrument transformer circuits.

   The EPRI investigator has witnessed such inadvertent events over decades of work experience, and takes its detection very seriously even though it has less emphasis in NERC standard compliant programs. NERC interprets the problem as a commissioning care issue, which is correct in principle.

   Most of these problems will be detected by the same techniques as are used for calibration in (1). But note that concern for detection of wiring errors increases the value of checking values between different locations (two ends of a line) or comparing them to the power system state as recorded by the control center. This brings in the SCADA RTU measurements for comparison if independent of the relays, or invokes the state estimator as an arbiter when the relays supply SCADA data.

   Another recurrent wiring problem not necessarily detected by these methods is accidental multiple ground connections in CT circuits. This issue will be addressed in more detailed solution design.

3. Detection of impending insulation failure.

   No monitoring technique is known to detect deterioration of insulation that is not yet impairing the conveyed signals. Utilities limping with dangerously disintegrating wiring or old seaside salt air substations are aware of these issues and must perform insulation tests (Megger© tests) to catch potential failures. But lacking these risk factors, no utility has published information showing that routine or periodic insulation testing has a meaningful chance of catching problems. On the other hand, the investigator has heard anecdotal complaints that insulation tests rarely expose any problem, yet have been known to cause hidden damage to equipment via improper test procedures. Wiring problems often show up when weather problems (e.g. rainwater in trenches) impacts measurement signals in an observable way.

   CT circuits carrying only low burden modern microprocessor relays and measuring devices are not subjected to transient high voltages during faults that might appear with electromechanical relay burdens, or with high impedance bus/transformer relay schemes.

4. Detection of CT remnant flux

   Heavy faults can leave CTs with a high level of remnant flux, close to the saturation knee, so that there is an increased risk of CT saturation for the next fault. Some utilities had a procedure for removing a CT from service and degaussing its core after such a heavy fault.

   In decades of industry work, the investigator has not found a report of a case where a CT with high residual flux was blamed for a protection misoperation. This could be a topic for research, but without a clear benefit. Whether such remanence could be detected or mitigated is not a concern for most maintenance programs, or for the current EPRI project.

Example of Monitoring and Gaps

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 as explained above; failure of a self-monitoring function generates an alarm and may inhibit operation to avoid false trips. Certain internal components such as critical output relay drivers and contacts are not monitored as also explained above, 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.

The following example, created by the EPRI investigator during development of the NERC Technical Reference on Protection System Maintenance, illustrates monitoring coverage and gaps.

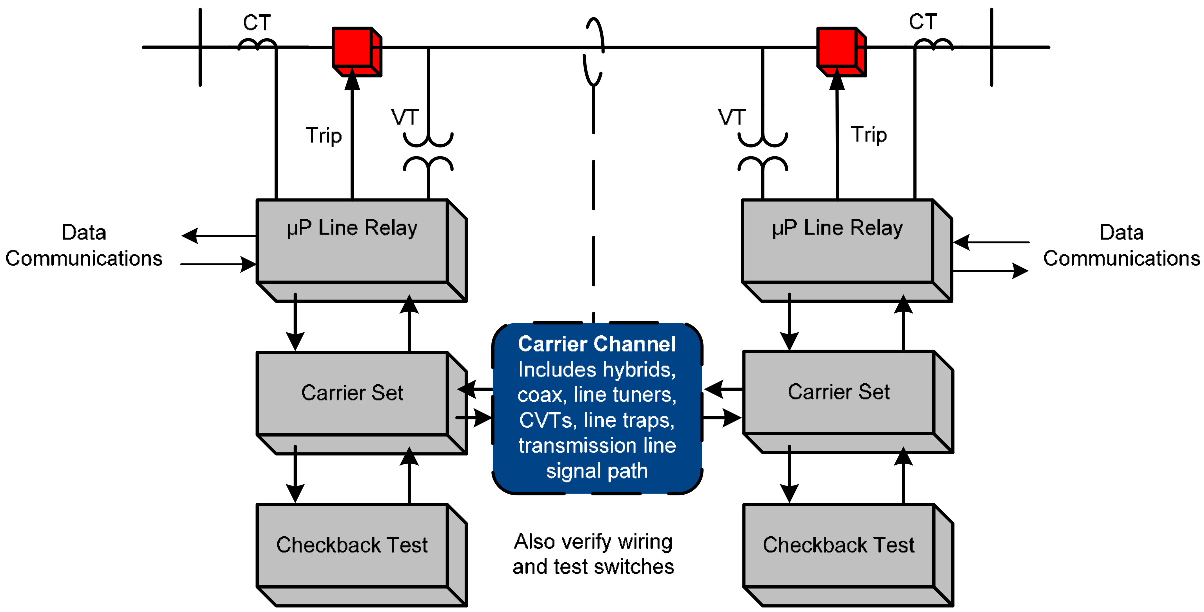

Figure 2-1
Example line protection application

Figure 2-1 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.

CBM verification takes advantage of the previously listed self-monitoring features of microprocessor 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. There are two redundant configurations as in Figure 2-1 so that there are ac measurements and breaker status to compare as described in the last section.
2. The relay has internal self-monitoring functions that report failures of internal electronics via communications messages or via SCADA. Maintenance personnel can see any alarm conditions the relay reports.
3. The CT and VT inputs to the relays are used for continuous calculation of metered values of volts, amperes, plus Watts and VARs on the line. Each relay has a data communications port that can be accessed from the control center, perhaps through a SCADA data concentrator, so EMS computers can check ac current and voltage readings. Comparison with other such readings to within required relaying accuracy verifies instrument transformers, wiring, and analog signal input processing of the relays.
4. Breaker status indication from auxiliary contacts is verified in the same way as in (3). Status indications must be consistent with the flow or absence of current.
5. Continuity of the breaker trip circuit from dc bus through the trip coil is monitored by the relay trip coil monitor (TCM).
6. 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 as shown. 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 5 plus the checkback test 6 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 boundaries of Figure 2-2 show the portions of the line protection system that are verified by monitoring. These segments are not completely overlapping, and within these dotted boundaries 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 an unmonitored output relay as described under Microprocessor Relays above. The components of the trip output whose functional state is unknown must work to trip the circuit breaker for a fault.

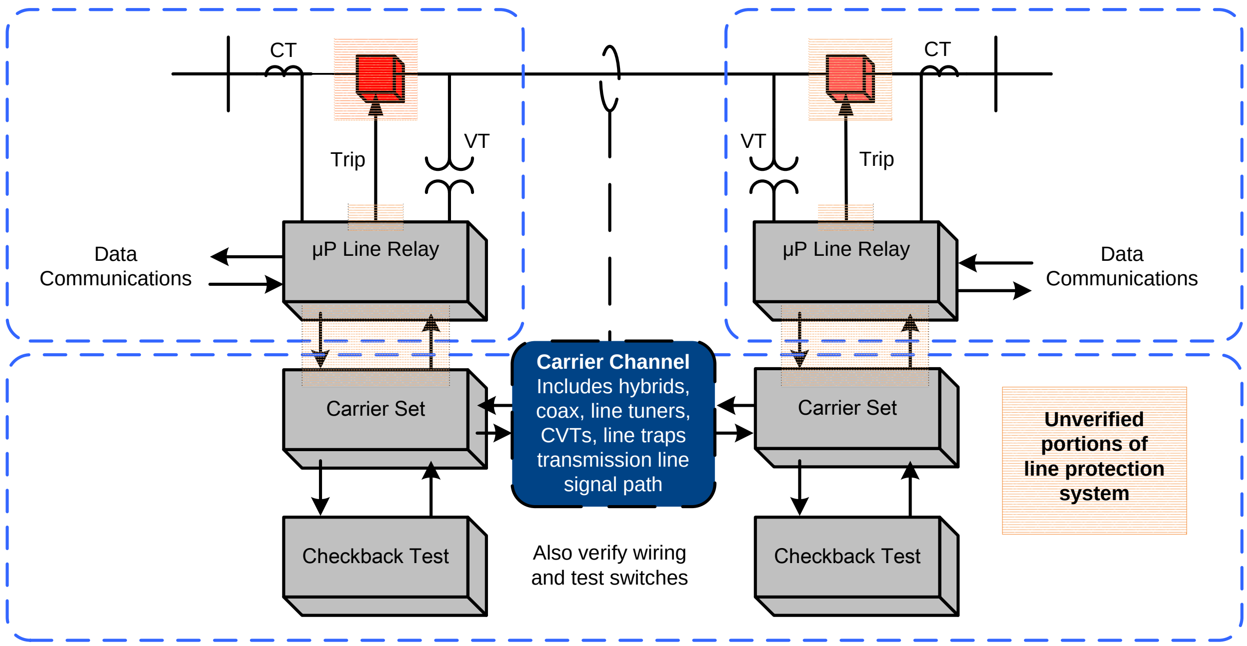

Figure 2-2
Monitoring gaps in example line protection application

3. The checkback test of the carrier channel does not verify the quiescent binary I/O connections between the relaying microprocessor internal decision programs and the carrier transmitter keying circuit or the carrier receiver output state.
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. This project will assume that there is no way to monitor the ability of a circuit breaker to interrupt fault current when commanded via trip coil energization.

Clearing of a naturally-occurring fault shows that the breaker is able to operate and interrupt, 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. We only know that at least one trip coil worked. A manually initiated trip command through each of the two trip coils separately does comprise a valid test of the breaker. This manual test can be done much less often (e.g. 5-6 years) than the normal 1 to 2 year interval for which most utilities want to observe breaker mechanical operation and current interruption.

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 shaded-block relay-to-carrier wired connections at both ends. This 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. This sort of discovery will be at the core of the present EPRI project.

3
SURVEY OF PROTECTION SYSTEM MAINTENANCE PRACTICES AND ISSUES

The project investigators developed a survey of practices and experiences for maintenance of protection systems, and obtained results from volunteers of EPRI Task Force Members. The goals of the survey are:

- To gather benchmarking information for EPRI participants.
- To gather statistics for approaches to maintenance.
- To gather economic data to help with the business case for low maintenance P&C
- To learn of organizational practices and issues that will impact implementation of low maintenance P&C

Survey Presentation to Respondents

The instructions to respondents indicated that the responses of survey participants are to be combined here without identifying individuals or companies. It explained that the survey seeks the following:

- To understand today's protection system maintenance program approaches and issues.
- To share aggregated results with EPRI participants.
- To understand how to develop low-maintenance P&C designs that are useful and serve the real needs of the industry.
- To get feedback and suggestions that improves the program results.

Presentation of Project Overview

The survey presented, in the final Question 18, an overview of the technical and business case for low maintenance protection and control. This case has been thoroughly explored in the prior Chapter 2 of this report; the overview is:

The EPRI project associated with this survey aims to research and demonstrate how a protection and control system can be designed to make the most of the condition monitoring capabilities of protection system components, to reduce or possibly eliminate the bulk of requirements for periodic maintenance testing. This potentially offers the benefits of:

1. Reduced time, effort, and cost of periodic maintenance.
2. More complete coverage of the protection system.
3. Failures are alarmed at once – no hidden failures waiting for discovery by infrequent testing or by a fault misoperation.
4. Reduction in human error induced damage or misoperation.
5. Technicians can focus their efforts where they will accomplish the most benefit.

However, this approach would change the way a utility runs its maintenance program:

6. Settings and configuration management becomes more important.
7. Technicians who are not performing frequent testing on reliable products will see their troubleshooting skills dull for these products – training on simulators becomes more important to insure readiness for fixing failures – more like training of system operators.
8. The components of self-monitoring systems (like communications links for local control) will require some new troubleshooting skills.

Details of Survey Questions and Responses

The full survey document appears in Appendix A.

Raw responses to the survey questions appear question by question in Appendix B.

The following chapter analyzes the grouped responses to each question in turn.

4
ANALYSIS OF SURVEY RESPONSES

This chapter presents summary and analysis of the responses to the questionnaire whose raw results appeared in Chapter 3. These are the investigators selected extracts, including judgment as to what elements of the raw results deserve focus – not all material is brought forward. Additional comments from an April 2011 webinar are included where relevant. The material is organized according to order of questions.

Question 1 Tables

Please give a brief overview of your maintenance program for protective relays and communications systems used with protective relaying systems, using the table at the end of this survey document

Quantities

Electromechanical relays still predominate – from 50% to 90% of relay population. This correlates with other surveys conducted by investigator on EHV protection practices, yielding similar results.

Conclusion

There will be large numbers of protection system replacements going forward that can take advantage of design approaches to be proposed in this work. The huge opportunity will be reduced only by industry effort to maintain the existing large and old electromechanical fleet for another decade.

Intervals

Electromechanical and static relays, lockouts – 2 to 4 years; limited by RRO requirements.

Microprocessor relays – 4 years where specified by RRO; otherwise 6 to 8 year interval yields good results.

Auxiliary relays – when scheme is tested; one respondent tests at 2 years.

Communications – Generally 1 to 4 year performance test. Manual checkback tests performed monthly where not automated. Data channels are monitored and are performance tested with the scheme.

CTs and PTs – generally tested with relays, display or instrument.

Trip coils – 2 to 6 years, with relay testing.

Batteries & dc supplies – 1 to 3 months for routine checks; 1 year impedance test or 5 year load test.

Conclusion

Most consistent are relay testing intervals. Electromechanical relay test intervals are 4 years or less. Respondents are comfortable and have good experience with extending monitored microprocessor relay testing intervals to 6-8 years. There is neither evidence for nor apparent concern about further extension for these relays.

There is little standardization of approaches or intervals for other protection system elements.

Test description

For microprocessor relays, respondents are split on approach. Some limit testing to A/D conversion, trip, alarm, and setting checks. Others perform dynamic tests and automated tests that plot characteristics.

Conclusion

A point of discussion and mutual education going forward is to understand what is being accomplished in testing activities. The investigators assert that dynamic tests or characteristic plotting for microprocessor relays validate the design or vendor programming of the relay, which serves no purpose for maintenance testing – these are not relay features that can break in the field unless settings are uncontrolled. This may be a remnant of practices that were highly relevant for electromechanical and static relays. It is not aligned with the direction and purpose of the low-maintenance strategy.

Triggers for testing

Mostly by spreadsheet or database; one respondent is working towards integration of testing program, plus entry and retention of data, with asset management system.

Other comments

The respondent with the lowest electromechanical relay population (50%) is running a vigorous asset sustainment program to replace these relays; this is consuming most technician time that would be used for maintenance.

A different respondent has installed a large number of substation P&C systems using IEC 61850 and GOOSE messaging for control. One uses vendor serial protocol for tripping via switchyard I/O module and fiber optic communications. Others are thinking about 61850 or about vendor serial protocols for control.

Question 1a

a. What makes your maintenance program testing different from commissioning testing?

All respondents have a thorough commissioning test, and a less comprehensive functional maintenance test, with many specifics shared.

Respondents vary in the degree of functional testing applied to relays. Some check basic I/O and analog interfaces, alarming, and check settings. Others perform a functional or characteristic check to make sure the relay is doing what the engineer expects.

Conclusions

A significant activity for this project going forward, as reported in Question 1 above, is to develop reasons and Pareto of findings driving the thorough functional testing of relays (elements and characteristics) during a maintenance test. The project must achieve a consistent view of how to resolve underlying issues to reach a low maintenance strategy in which such testing is not routinely performed.

Reported problems deserving focus in low maintenance P&C design

- Settings not trusted or found to be incorrect.
- Multiple CT circuit grounds found.
- Meggering and degaussing are specifically viewed as not useful or necessary after commissioning.

Question 2a

2. How is the testing work organized?
    a. Are there different categories of maintenance staff for relays versus communications?
        i. If you have any communication-assisted protection schemes, which group is responsible for the communications part?
        ii. What work rules or union rule constraints impact how work programs are defined and assigned?

Respondents are split – some have at least separation of relay versus communications technicians, while others use the same technicians for all protection system elements.

Union rules may require union personnel to perform maintenance work, but do not seem to impose other constraints on the program.

Conclusion

Project needs to review whether or how a split maintenance organization impacts the design of a low maintenance P&C program

Question 2b

b. Please describe your approach to sending staff to a particular station:
    i. To test all relays and/or communications in the station in one session?
    ii. Or to test specific equipment for which they are trained and equipped?
    iii. Or to test only items with approaching maintenance due dates?
    iv. Or other approach to maintenance dispatch?

Most maintenance testing is driven by scheduling for each protection system. There may be informal effort to group items at one location with similar due dates. One respondent may have technicians focused on maintenance testing versus other repair or testing work, but in general any qualified technician can perform maintenance testing.

Conclusion

We note one respondent's observation that maintenance tests require advance system planning studies to evaluate the impact of the maintenance outage, with 45 day to 6 month lead time for the studies. The cost of these studies is a business case cost to consider, although significant system study is required in any case to insure operation during forced outages.

Question 2c

c. How do maintenance personnel record the results of maintenance testing?
    i. Are specific test results kept?
    ii. Is there any view of maintenance results across populations of similar devices?
    iii. Is there an activity that detects population problems or trends?

Respondents generally retain all records in some electronic format, which may be paper scans or relay test set output result files. One respondent stores results in the asset management software system.

There is no consistent program of analyzing maintenance test results. Results are pass/fail in most cases. Some respondents are driving to achieve this visibility and analysis of results. There may be informal organizational knowledge of problematic products, with increased focus on testing.

Conclusion

Respondents are far from ready to implement a performance-based maintenance program. They may benefit from guidance on how to set up the data collection and analysis process that could possibly support an effective program that is also complaint with coming regulatory requirements.

Question 3

3. What is your *estimate* of the *percentages* of protection and control maintenance staff *time* spent on:
    a. Repairs and troubleshooting with associated travel & overhead work.
    b. Routine scheduled maintenance testing with associated travel & overhead work.
    c. Other – please describe.

Repairs require 10% to 33% of technician time. Routine maintenance takes 40% to 80%, with 20% and 33% estimates from users whose technicians are busy commissioning new installations (33% to 60% for commissioning upgrades).

Conclusion

The sustainable asset strategy of frequent replacement of modern relay types, plus upgrading of old relay installations, provides a lot of work for available technicians. For most respondents, it appears that there can be huge value in reducing the routine maintenance workload. Commissioning and repairs comprise plenty of work for today's pool of technicians, which is known from studies in other EPRI projects to be shrinking in any case. This should comprise a major business case driver for low maintenance P&C design. One respondent said exactly this in response to Question 4.

Question 4

4. Can you provide an estimate of cost for maintenance testing for a typical microprocessor-based transmission line protection system (one of a redundant set, or all redundant sets – please specify)?
    a. How many different groups are involved?
    b. How many man-hours or man-days are required?

Responses varied widely but seem to center around a man-day per protection system. Low estimate – 4 hours plus drive time of up to 12 hours round trip; high estimate 14 hours; one statement of one week for calibration.

Conclusion

Further project discussions should focus on estimating a dollar value on a day of time for a properly equipped technician with transportation, multiplied by the number of tests that might be reduced or eliminated.

Question 5

5. How are relay maintenance personnel trained, and kept up-to-date for skill sets?
    a. How are skills updated with new equipment or requirements?
    b. Do you have any live P&C panel simulators for training?
    c. Can you estimate the training/education cost per person per year?

Most training is handled in-house with ongoing programs and instructors – some centralized, some carried to field sites. Cost estimates range from $7k to $20k per year (latter represents more intensive training during first years of career).

Respondents are split on use of lab panels for training.

Conclusion

This EPRI program does not aim to reduce training; the question is for participant information only. With new technology of relays and data communications in low maintenance designs, continuing training will certainly be needed.

The investigators assert that lab panels will become more important for training and troubleshooting when low-maintenance P&C is deployed. One user looking at IEC 61850 designs seems to accept this and is planning on such panels.

Question 6

6. Please describe your testing approach for microprocessor relays:
    a. What events trigger testing?
    b. For a protection scheme with multiple relays and communications links, do you test component relays, test full panels as a functional unit, test end-to-end, or some combination?
    c. How do you assure that the relay(s) can properly trip breakers?

Respondents are split – some test components; three of five include end-to-end tests. Four use functional testing of systems or subsystems; one separates communications testing but tests the rest of each protection terminal as a unit. Most trip breakers from relays during relay testing.

Conclusion

The focus on testing seems to be functional, although specific approaches vary for practical reasons. Respondents are focused on knowing that relays can trip breakers based on relay test intervals; any mechanical aspects of breaker testing are in the domain of breaker-responsible parts of the organization.

Question 7

7. Please describe your testing approach for relaying communications channels:
    a. Power line carrier
    b. DS0 or other TDM, on SONET or digital microwave
    c. Analog leased circuit or analog microwave
    d. Other

Note that results overlap with responses to Question 8; these should be considered together.

Two on-off carrier users use monthly manual tests rather than automatic checkback. One FSK user does perform an annual shift check along with guard monitoring. Analog channels get annual performance tests. Users who responded on digital channels are taking advantage of self monitoring ability.

Conclusion

There is no apparent roadblock to self-testing and performance monitoring as tools for reduction or elimination of manual communications system maintenance testing. This is a central feature of a cost effective approach.

Question 8

8. Please describe if or how you utilize the self-monitoring or self-testing capabilities of:
    a. Microprocessor relays
    b. Pilot protection channels – carrier
    c. Pilot protection channels – DS0, other TDM, on SONET or digital microwave
    d. Pilot protection channels – analog leased circuit or analog microwave
    e. Other channel or protection system component types

Note that results overlap with responses to Question 7; these should be considered together.

All users connect microprocessor relay alarms to annunciators and/or SCADA. Channel alarms are used as provided by vendors of particular equipment types. One respondent sends performance monitoring outputs of digital channels to a separate monitoring center (perhaps a telecoms operations center).

Conclusions

One respondent made the critical observation that they do not know what the internal monitoring of relays really covers, and wonders if standardization is possible. The investigators feel that standardized disclosure or documentation is the minimum critical result to achieve for the benefit of the industry.

Monitoring and alarms are universally used when provided. Respondent organizations seem to assume that the vendor knows what needs to be monitored. A goal of the present EPRI project is to use the concept of gapless monitoring to document what needs to be monitored, and drive for product or system designs to close any gaps in existing designs.

Question 9

9. Are you using any data communications systems within substations (such serial or Ethernet data connections):
    a. To actually perform a high speed protective function like critical measurement or tripping?
    b. To monitor any part of a protection system?
    c. Others?

One user employs vendor-specific serial communications over fiber to switchyard I/O units for tripping, and plans a GOOSE project. Another already uses IEC 61850 GOOSE messaging in the same way. The GOOSE user raises critical questions:

How to test GOOSE control points?

If we are using GOOSE self-monitoring, or any other 61850 devices with self monitoring – does the modeling (logical nodes) support reporting of failures as part of the automated 61850 system engineering process? Or must these alarms be configured manually?

Conclusions

Both testing and monitoring of status and control points sent on multiplexed digital communications paths should be considered in the EPRI design work.

The investigator is engaged in initiating a project within IEC 61850 standards development to model secondary system (protection and control system) condition monitoring so that reporting is part of 61850 automated engineering and configuration process. This capability does not exist yet. The EPRI project may define needs for which this standards work should respond, once it begins.

Question 10

10. What has been your experience with self-monitoring?
    a. Do you use it to extend testing intervals?
    b. Any experience of undetected problems?
    c. Have you used monitoring to completely eliminate human testing on **any** items of equipment?
    d. How and where are alarms reported and acted upon?
    e. How is the alarming function tested?

Only one respondent overtly extends microprocessor relay maintenance intervals due to monitoring. But RRO limits of others may embed an extension as compared to electromechanical relays. Only one user's SONET is exempt from testing because of its inherent monitoring.

Alarms are transmitted via SCADA for control or operations center action. Alarming output to SCADA is tested at time of relay test.

Respondents reported two cases of relays with failures that did not alarm. Speculation on one case: failed input transformer might have impacted only current measurement on one phase – the relay could not report this, and an external metered value check would be required to catch the problem during a load cycle in service. For the other case, the relay should have alarmed the failure but did not do so and had to be rebooted – this is a vulnerability that would have to be addressed by vendor design correction.

Conclusions

Users have not yet embraced monitoring for elimination of maintenance. The present program aims to provide a basis for them to take advantage of this capability.

While gapless monitoring is clearly defined as described in Chapter 2, one risk is with products having design flaws by which monitoring fails to work. These are not widespread, but the reports given here are not the only ones heard by investigators in their industry work. In particular, cases of relays with locked-up processors but no alarm, needing rebooting, have been heard elsewhere. Vendors must be asked to report on experience and resolution of root causes of such problems.

While needing investigation and action, these vulnerabilities do not outweigh the benefits of monitoring or the risks of *not* taking advantage, as reported under other questions.

Question 11

11. How do you assure that microprocessor relay settings are correct during maintenance?
    a. What is the reference for "correct settings"?

Three or four respondents use an electronic database and compare as-left settings with the database to validate the field installation. One reviews a settings sheet managed by protection engineers. Two respondents are clearly focused on having a version-control archive and settings life cycle management.

Conclusion

Having a version-control archive and settings life cycle management is central to a low-maintenance P&C design approach. Only users with routine manual testing of full relay behavior can assure that relays are set correctly if they are not using tight control and validation of the field settings files themselves. Another EPRI project has investigated version control tools and methods.

Question 12

12. What is your experience with protection system problems or misoperations induced by human errors during testing and maintenance activities?

The respondents all brought additional validation to the assertion of the investigators that human errors during maintenance work are a major cause of misoperations. One said that over 50% of misoperations were caused by maintenance and testing errors. There is significant evidence from other utilities outside the EPRI study showing incidence in the range of 25-33%.

Changing settings to test without correct restoration, opening incorrect test switches, or failing to restore test switches are typical causes that were reported here.

Conclusion

Avoidance of misoperations from human maintenance is a major driver for low-maintenance P&C development. What is a reasonable to use this in the business case? The most recent industry blackout incident in the San Diego area appears to have as one of its elements (not the only element) a human protection system maintenance error. There have been other noteworthy incidents like this in Florida and California over the last two decades.

Question 13

13. What do you feel are the gaps or issues:
    a. In your protection system maintenance program or results?
    b. In your protection communications maintenance program or results?
    c. In the design of products you are maintaining?
    d. In the maintenance tools that are available?
    e. Other issues?

This question brought restatements of issues that respondents had presented under other questions. Notable points:

- Compiling data on results for PBM.
- Lack of understanding of completeness or gaps in monitoring.
- Human challenges due to variety of equipment types and design standards in use.
- Need for strong databases to support maintenance programs and results.
- Design errors (bugs) in microprocessor relays.
- Design for safe and convenient maintenance and testing in systems using data communications for status and control points.
- Need for well understood suite of IEC 61850 tools.

Question 14

14. What are your testing approaches, intervals, and experiences with electromechanical auxiliary relays?
    a. Auxiliaries in the tripping path.
    b. Auxiliaries in roles other than direct tripping.
    c. Lockout switches or multi-trips.

Most respondents test these devices when the protection system is tested. One does not test non-trip auxiliaries after commissioning. One reported never finding a lockout switch problem. Industry experience outside the current survey shows there are problems, which may be dependent on vendor and on generation of design.

One respondent uses a breaker IED (microprocessor based I/O protective relay) as the focus for all breaker tripping, and thus avoids the use of all lockout switches.

Conclusion

There is no obvious roadblock, but not yet much movement, towards P&C designs that eliminate these devices. One respondent with an active relay replacement program uses such a program.

Question 15

15. Do you analyze transmission relay operations when the overall protection operating result is what you expected?
    a. What data do you check?
    b. What data do you retain for future reference?

All respondents check data from every operation – certainly for NERC bulk electric system (BES) operations, and for most non-BES faults. Checking BES operations makes sense, since all misoperations must be reported to RRO or NERC – you must know if you had a misoperation by checking all operations. Checking others is still a good maintenance practice.

Respondents seem to archive all operations data. Indefinite retention seems to go beyond the need for correct operations, but no such distinction is being made.

Conclusions

Low-maintenance P&C system design would be strongly supported by the most convenient possible tools and presentations of results from operations. Operations may expose hidden problems in device installation or settings that escape detection during manual testing or by monitoring functions.

Archiving is beyond the scope of this work, but the need should be considered in design.

Question 16

16. Give a brief overview of differences in protection system maintenance programs among bulk transmission, lower voltage transmission, and distribution systems.
    a. Time intervals
    b. Activities
    c. Use of microprocessor relays or monitoring.

Respondents provided little response to this question. There were a couple of indications that non-BES protection and switchgear installations get less frequent attention.

Conclusion

Users are not as focused on non-BES protection. The investigators suggest that a best practice is to have the same maintenance approach, or at least minimal variations, at all levels of the system. While BES protection is subject to regulatory auditing, customer reliability and avoidance of disastrous primary failures depends on good protection system performance at all levels. Low maintenance P&C strategy makes this more practical – the standard approach is applied in the design phase and via organizational arrangements that serve all levels. This does not add cost in the way that an intensive time-based maintenance program for lower voltages would do.

Question 17

17. How has your protection system maintenance program being changed as a result of regulatory reviews or audits imposed over the last five years?

There was no theme in the responses. One respondent is keeping more documentation than before. Two others have looked for ways to eliminate some testing activities from their programs. One indicated awareness of developing NERC PRC-005-2 and intention to adapt to its requirements.

Conclusion

While responses did not complain of regulatory pressures, the investigators believe that the low maintenance P&C strategy must support compliance with NERC PRC-005 standards to be accepted by users. This does not conflict with the most important drivers – cost savings and increased reliability of protection.

Question 18

18. The EPRI project associated with this survey aims to research and demonstrate how a protection and control system can be designed to make the most of the condition monitoring capabilities of protection system components, to reduce or possibly eliminate the bulk of requirements for periodic maintenance testing. *(Question includes detailed listing of benefits and user changes/issues).*

    a. What is your reaction to this initiative on protection and communications system design?

    b. How do you think others in your organization would react?

    c. What specifics would you like to see included?

    d. What advice or cautions do you offer to the project team?

    e. What do you think is needed to bring about acceptance of the results, assuming they are technically plausible?

Respondents are universally enthusiastic about the work and support continuation by the EPRI team. Responses included "very interested in investigating", "more monitoring", "wonderful thing to research", and "needed and helpful."

Respondents are split on how their organizations will react. Some think this will provide welcome relief for manpower pressures, while others see a steep learning curve and resistance of experienced personnel who may fear impact on their jobs.

Specifics cited here include:

- Need for better understanding of monitoring inside IEDs (also cited above).
- Monitoring in an Ethernet-based IEC 61850 based design.
- Hidden failure modes and detection.
- System-level checking to cover gaps.
- Stay practical – not everything will be replaced at once – what about existing designs? And do not be completely dependent on cutting-edge technology.
- Include a business case that helps with regulatory support of funding for changes.
- Make sure the approach is NERC compliant.
- Can the project document types of failures, types of human errors, and how the new designs will help?

Conclusions

The respondents are enthusiastic about continuing the work defined in the roadmap for the EPRI project.

The bullet list above comprises items that should be recognized in the work plan given below.

Some requests are challenging for the project – in particular, monitoring to eliminate human testing requires certain design upgrades and can't be fully achieved with existing designs. The program should help as much as possible with improvement of existing designs and testing approaches, but this cannot yield the full benefits.

Detailed gathering of failure and human error experience data may be difficult because of organizational publicity concerns or weak record keeping. This would be a significant detective case on its own. NERC or RROs may keep confidential information that is not accessible to project investigators.

5
STATUS OF NERC PRC-005-2 PROTECTION SYSTEM MAINTENANCE STANDARD DEVELOPMENT

Background Information on the NERC Standard

In 2007, NERC System Protection and Control Subcommittee (SPCS), formerly known as System Protection and Control Task Force (SPCTF), developed the technical reference for Protection System Maintenance that serves as the basis for the technical approach of PRC-005-2. NERC Protection System Maintenance and Test Standard Drafting Team that has been creating NERC Reliability Standard PRC-005-2, *Protection System Maintenance*, still in draft form at time of writing This chapter thus gives an brief overview of the progress in development of this NERC Standard.

The SPCTF 2007 Technical Reference is still available at http://www.nerc.com/docs/pc/spctf/Relay_Maintenance_Tech_Ref_approved_by_PC.pdf.

Current public project documents and drafts of PRC-005-2 are available at http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html.

The new PRC-005-2 is one of the most technically complex reliability standards to come from NERC to date. This is driven in part by FERC order 693, specifying that this new standard states complete specifics on required maintenance activities and maximum maintenance time intervals as a function of types and generations of equipment. However, there is additional complexity in the new condition-based and performance-based maintenance approaches the standard allows – these are the escape hatches for utilities who would like to reduce the amount of strict time-based maintenance that FERC ordered.

The new NERC PRC-005-2 will also absorb existing NERC PRC-008-1, PRC-011-1, and PRC-017-1 on maintenance of underfrequency and undervoltage load shedding systems (UFLS/UVLS), and special protection systems (SPS). They are all built from the same types of protective relaying equipment.

PRC-005-1 and PRC-005-2 apply to large generating facilities and to transmission facilities of the Bulk Electric System (BES). The BES is currently defined by the eight regional reliability organizations (RROs) comprising NERC – each RRO has its own definition for its region. Now a separate NERC drafting team is working on a common North American BES definition. See the status of NERC BES definition work at http://www.nerc.com/filez/standards/Project2010-17_BES.html. FERC sees the BES as including all facilities operating above 100 kV, as well as medium to large generation facilities, but this is not the official criterion for determining which Protection Systems are subject to the NERC standards.

Relationship of PRC-005-2 to the EPRI Project

This EPRI research project is not intended to provide members with guidance on compliance of NERC reliability standards. Compliance is out of the scope of this R&D project. However, the project investigators will study the regulatory standards to avoid confliction of the R&D results with the existing or upcoming regulatory standards. If the work does not pay attention to this need, the project results may not be applicable to members.

The EPRI investigators observed that the standard PRC-005-2, which is still at drafting stage, has been specifically conceived to allow the protection system owner to create a program incorporating condition based maintenance (CBM), and to allow extended intervals and reduced work for time-based manual maintenance activities as a result of CBM. In addition, certain maintenance activities may possibly be completely skipped if the condition monitoring meets specified technical requirements for reporting of failures.

Although the draft of the standard provides the CBM option, on the technology side how to leverage the condition monitoring while maintain the same or higher reliability remains an open question for most utilities. Therefore, this project aims to address this technical question and support members in development of their own CBM in future.

It is worth pointing out here that although the relevant regulation standards will be studied, the EPRI project is *not* avoiding any exploration of technology or design features that are *not* compliant with regulatory standards. *Non-compliance* means that some monitoring feature discovered in this work may not bypass or avoid the need for manual testing that the standard requires. However, that monitoring feature may still be valuable in helping the protection system design meet other key objectives – such as immediate discovery and reporting of a malfunction that would otherwise be undiscovered and would lead to failure, damage, or misoperation of a protection system component. Such a technique could be very attractive even without the test-saving benefit.

Overview of PRC-005-2 Development Steps

- February 2007 – FERC issues Order 693 making PRC-005-1, the existing NERC Protection System Maintenance and Test Standard, mandatory and enforceable. PRC-005-1 has no specific requirements for activities or time intervals – it leaves that up to the asset owner. FERC also orders NERC to develop a new version of the standard with specified maintenance activities and times relevant to the equipment being maintained.
- September 2007 – SPCTF issues its Technical Reference on Protection System Maintenance. The authors make specific recommendations for a time based maintenance program that FERC required. But it also includes principles for extending maintenance intervals, reducing activities, or completely eliminating human intervention if monitoring is provided according to specified technical requirements. The Technical Reference also proposes that a performance-based program is acceptable with sufficient data on the reliability of the population being maintained.
- December 2007 – Drafting team begins work on PRC-005-2, starting with SPCTF Technical Reference.

- June 2009 to May 2011 – The drafting team posts first draft of PRC-005-2 for industry comments. The posting also includes Frequently-Asked Questions (FAQ) application guidance documents, and a revision of the Technical Reference according to the Standard as written. The draft did not achieve a two-thirds approval of the balloting body; comments of industry balloters require detailed individual responses. The draft receives multiple rounds of detail improvements and revisions in response to comments until Draft 4 receives industry approval (67%) in May 2011. Draft 4 is accompanied by a combined Supplemental Reference and FAQ document.
- June 2011 – Comments on Draft 4 and resulting revisions require a recirculation ballot. The fifth draft of PRC-005-2 was posted and barely missed two-thirds approval of the balloting body of industry entities. The drafting team revised the standard, and updated the Supplemental Reference and FAQ. Nonetheless, the project required a restart at this point according to NERC rules.
- September 2011 - The NERC Standards Committee authorized re-initiating the project with a posting of the Standards Authorization Request (SAR) and revised standard draft for a 45-day comment period, with an initial ballot of the standard conducted during the last 10 days of the comment period. The Drafting Team was also opened for application of new members. Existing members were reviewed and retained; a few new members joined the team.
- October 2011 – The initial ballot of the recomprised project did not achieve approval. The reformed drafting team is presently responding to comments and revising the standard draft.

The project thus remains on the same development track that it has been on since 2009, with many of the same participants, and a gradually evolving version of the standard draft.

Recent Issues in Standard Development

The NERC Project 2007-17 link above accesses documents giving long catalogs of comments and drafting team responses related to PRC-005-2. Many comments have led to improvements to the standard.

In September of 2011, the Drafting Team presented a webinar to the industry in which it explained the following issues that had drawn comments:

- 3 month maintenance interval for basic dc battery checks – while all the longer maintenance cycles in the standard had built-in grace periods, the 3 month interval was strictly based on IEEE Standard 450 on battery maintenance, which is the actual interval used by many balloters. Since 3 months is the maximum allowed interval, most of the industry would have to adopt shorter intervals like 2 months to avoid any risk of noncompliance. In the latest draft, the interval is extended to 4 months.
- Interpretation of applicability to Protection Systems at the boundary of the bulk electric system (BES) – PRC-005-2 states that it applies to *Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)"* – all terms that are fully defined in the NERC glossary. PRC-005-1 used the term "*transmission* protection systems" which is undefined; and a recent interpretation (NERC Project 2009-17) defined a slightly different boundary at a non-BES transformer connected to the BES. In the interpretation, a Protection System is included "*… only if the protection trips an interrupting*

device that interrupts current supplied directly from the BES and the transformer is a BES element." This interpretation excludes a few protection systems from the maintenance requirements, which PRC-005-2 wording includes in its applicability. This drew complaints and demands for alignment with the PRC-005-1 interpretation. However, PRC-005-2 is properly based on fully defined NERC terms and has not been changed.

- Non BES protection systems for the BES – the tables included numerous exceptions of maintenance requirements for components that are part of a distributed underfrequency or undervoltage load shedding scheme (UFLS or UVLS), or a special protection system (SPS) that trips distribution loads. It was not clear to many readers that these requirements were relaxed. A new table has been added which pulls out requirements for these distribution-level applications and shows clearly what has to be done, which is largely less than for BES protection. Some activities like breaker test tripping can be skipped altogether.
- Changes being made at the time of this report focus on clear definition of what action is required when a failure is discovered, especially when it cannot be corrected on the spot during maintenance. Documented initiation of action is key, rather than complete resolution of the maintenance problem which can be unpredictable.

While there is a vastly longer list of issues and changes over the six drafts of the standard, these examples demonstrate that such changes do not bear on the core approach and direction of this EPRI research project.

Maintenance Tables

Tables 1 through 3 in PRC-005-2 present maximum maintenance intervals and activities as a function of component type and its functional monitoring capabilities. These tables begin on Page 10 of the draft available at http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html. The tables are the central feature of the standard to which the EPRI work will refer when proposing designs.

Each specific Protection System component type has its own table. The tables are organized with three columns listing the functional attributes of the component, the maximum allowed maintenance interval in calendar years or other calendar time units, and the functional activities that must be performed within that time interval.

Table 5-1
The PRC-005-2 tables

Table Number	Table Title
Table 1-1	Protective Relays
Table 1-2	Communications systems
Table 1-3	Voltage and current sensing devices providing inputs to protective relays
Table 1-4(a)	Protection System Station dc Supply Using Vented Lead-Acid (VLA) Batteries
Table 1-4(b)	Protection System Station dc Supply Using Valve-Regulated Lead-Acid (VRLA) Batteries
Table 1-4(c)	Protection System Station dc Supply Using Nickel-Cadmium (NiCad) Batteries
Table 1-4(d)	Protection System Station dc Supply Using Non Battery Based Energy Storage
Table 1-4(e)	Protection System Station dc Supply for non-BES Interrupting Device for SPS and non-distributed UVLS and UFLS
Table 1-4(f)	Exclusions for Protection System Station dc Supply Monitoring Devices and Systems
Table 1-5	Control Circuitry Associated With Protective Functions
Table 2	Alarming Paths and Monitoring
Table 3	Maintenance Activities and Intervals for distributed UFLS and UVLS Systems [Relaxed requirements compared to those in tables above]

Calendar years of maximum maintenance intervals cited in the tables means that the starting and ending activities whose interval is measured can be at anytime within their respective years. For example, if an electromechanical distance relay with a 6 calendar year maximum interval was tested any time in 2006, the next test must be completed by December 31, 2012. There is no grace period after this under any circumstances – January 1, 2013 is not compliant with the standard. So scheduled maintenance dates should well in advance of the deadline – many utilities schedule a year of margin.

A review of the tables shows that they are completely functional – they tell the asset owner what maintenance result must be achieved, but do not specify how to get to that result. The asset owner needs to document how the results are achieved. This latitude leads to EPRI research and development work in low maintenance P&C strategies as this project is conducting.

Supporting Documents

Drafts of the standard have been accompanied by supporting application documents – a Supplemental Technical Reference that updates the 2007 SPCTF document linked above, and a Frequently Asked Questions (FAQ) document explaining how the drafting team intended users to interpret and apply the requirements in practical installations. Since Draft 4 of the standard, the accompanying Supplemental Reference and FAQ have been combined into a single document.

6
PROJECT ROADMAP

The project roadmap has been proposed and presented on a high level to the EPRI P&C Task Force during meetings and webinars at the beginning of 2011 This chapter provides an updated and enriched version of the roadmap, which incorporates the important findings from 2011 survey work.

2011 Activities

The project began in the spring of 2011 with the stated goals of needs assessment, identifying current utility practices, and project planning. The specific activities and requirements are listed here with status update for each.

1. Focus on protective relays and associated communications.

   Chapter 2 of this report explains the particular implementation of this principle. Briefly, the goal is to produce industry perspectives and applicable approaches for developing low maintenance protection systems, while leveraging the work from other EPRI task forces on maintenance of circuit breakers, instrument transformers, and batteries. To get a complete result, this project must look at how protection systems interface with substation dc supplies, circuit breakers, and instrument transformers. EPRI work on these relevant subjects will be referred in the final report.

2. Perform survey of participants' and industry P&C maintenance practices.

   The comprehensive survey is presented in Chapter 3 and Appendices A and B. The responses are analyzed in Chapter 4; the survey is the major task in 2011 work. With survey results in hand, the project investigators will review industry status, perform needs assessment, set project goals and milestones, revise the roadmap, and propose the 2012 work plan to move towards the goals.

   A new survey of maintenance practices of the broader industry is beyond the scope of the EPRI project. The project investigators do note the existence of the 2007 Technical Reference on Protection System Maintenance at http://www.nerc.com/docs/pc/spctf/Relay_Maintenance_Tech_Ref_approved_by_PC.pdf . To support the recommended maintenance intervals, SPCTF surveyed protection system component maintenance intervals for utilities representing about two thirds of the installed generating capacity in North America. The intervals in the maintenance tables of draft PRC-005-2, found at http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html, represent averages for that utility base, rounded to next longer times (in whole months or years) and further augmented to include built-in grace periods.

Relevant information can be found in published reports of IEEE Power and Energy Society (PES) Power System Relaying Committee (PSRC) working groups. A 2001 report of WG I11 at http://www.pes-psrc.org/i/ presents a survey of relay testing practices. At the core of this report are test intervals used for a variety of very specifically identified equipment types. It is important to note that this report is ten years old and predates the current regulatory and auditing environment, as well as many of the microprocessor based protection system components available today.

3. Assess needs for lower maintenance costs.

   This assessment results in particular from the responses to Questions 3 and 18 among others. However, the business case includes more than just the cost of the time, effort, and equipment in use. These drivers have been found or are proposed as more significant that testing cost:

   - Better manage inadequate supply of trained technicians for commissioning of new installations and for troubleshooting work – free up precious manpower by reducing maintenance testing. What is the value of completing planned repairs and replacements on schedule and with high quality of work? What is the demographic trend for maintenance expert population in the future?
   - Reduce misoperations due to maintenance activities that can be avoided. While most of these misoperations are not disastrous, widely publicized major blackouts have resulted from maintenance errors. Avoiding the risk of low-probability high-impact events that degrade revenue and public good will, while bringing invasive regulatory investigation, has significant business value.
   - Alarm failures when they occur, avoiding many of the misoperations that are not caused by human errors in maintenance. Hidden failures may persist for years before discovery by maintenance testing or by misoperation.
   - Develop automated processes for tracking reliability performance of specific equipment types, supporting performance based maintenance programs that optimize maintenance intervals with a minimum of human data collection.

4. Review state-of-the-art for condition monitoring.

   Chapter 2 analyzes opportunities. 2012 and 2013 roadmaps include specific equipment and system design investigations leading to specific solutions.

5. Analyze gaps and present phased plan for developing low maintenance P&C

   Chapter 2 presents the nature of gaps to be addressed in the phased plans of this chapter. The bulk of monitoring design opportunities are straightforward and can be turned into specifications and design guidance. The survey has pointed to some less obvious opportunities not previously considered by the investigators, which may be addressed in developing solutions as the project continues. Examples of ideas for closing subtle gaps are:

   - Detection of multiple grounds in CT or PT circuits.
   - Detection of failure of FSK channel that transmit guard but is not known to be able to execute a required frequency shift.

- Detection of operating state of a transformer sudden pressure relay.
- Detection of instrument transformer or analog value errors and failures in faster time frames than those supported by SCADA.
- Detection of circuit breaker mechanical state via trip current profile behavior – in the scope of other EPRI work and tracked only indirectly in this project.
- Detection of analog or status errors by evaluation of dynamic signals during faults and operations.
- Condition monitoring methods for trip outputs of protective relays.

These may be optionally implemented depending on whether particular users have experienced problems addressed by that particular solution.

6. Create roadmap – the present chapter.
7. Update EPRI Task Force on NERC PRC-005-2 – Chapter 5 and August 2011 meeting presentation to Task Force.
8. Provide status updates & presentations – Two webinar contributions and August 2011 meeting session, plus the present report.
9. Develop multi-year project plans – the contents of the present chapter.

Proposed Project Plans for 2012

The next phase will focus on development of a first draft of system design guidelines and specifications to achieve low maintenance protection and control systems, with analysis of enabling technologies and technical gaps. The guidelines will include a first listing of specifications for products and their integration.

Note that Task Force members indicated in Chapter 4 survey results that they see a need for some degree of standardization of vendor features or practices for monitoring to support their design work, and standardized documentation to support their own design compliance documentation. The first draft guidelines and specifications, and the vendor documentation example of Step 4 below, are aimed directly at pushing the supplier community to meet this need. EPRI does not make industry standards, but these R&D results may have the potential to help the industry develop proper standards that help utilities lower maintenance costs and increase system reliability.

The design guidance and specifications aim to provide the best solution by leveraging the state-of-the-art of condition monitoring technologies for P&C systems. On the other hand, to make the R&D results applicable and useful to utility members, the existing or upcoming regulatory standards on P&C system maintenance requirement will be considered during the development of the guidance and specifications.

The proposed 2012 work plan:

1. Research and categorize typical or widely available product designs and enabling technologies used to build protection systems based on condition monitoring. The planned approach is to sample design specifics for example relays and communications products, and propose their use in Protection System designs that minimize maintenance while assuring reliability. The application scenarios will show major choices between today's widely used practices and those supporting reduced maintenance.
2. Develop first draft of high level design guidance and specifications document based on these products technologies. (Completed document to be developed in 2013.)
3. Identify gaps and current or future technology developments.
4. Draft a first draft example of vendor documentation which utilities can use in conjunction with design standards for documentation of self-monitoring designs.
5. Conduct an industry workshop to review results and to engage product vendors in the development process.
6. Continue to collect and document current industry practices, experiences, needs, and concerns with member utilities.
7. Continue status updates for EPRI Task Force members on project steps described above – webinar contributions and meeting presentations.
8. Begin planning 2013 laboratory demonstration with Task Force member utilities.
9. Produce update report.

Proposed Project Plans for 2013

These steps are subject to change depending on 2012 findings and project progress. Laboratory work completion and any field demonstration will likely carry on into 2014.

The work will fill in the 2012 first draft of system design guidelines to make a proposed first edition, including specifications. Based on these guidelines and specifications, the project will create low maintenance system design test bed or demonstration systems in relay labs of EPRI and/or Task Force members. The specific steps are:

1. Complete the first edition of system design guidelines for Task Force member comments and review, based on 2012 first draft.
2. Specify test bed/demonstration system in laboratory. Obtain Task Force feedback and jointly determine the implementation venue or scenario, as well as equipment sources.
3. Create high level design for test bed/demonstration based on specifications, test bed circumstances, and available equipment.
4. Build test bed/demo system in designated laboratory.
5. Debug lab demo system and harden design documentation.
6. Demonstrate selected monitoring features.
7. Update guidelines and specifications based on experience with demonstration system.
8. Continue status updates for EPRI Task Force members on project steps described above – webinar contributions and meeting presentations as scheduled by EPRI Project Manager and Task Force.

9. Begin planning 2014 activities with Task Force member utilities.
10. Explore plans for field demonstration or implementation in utility substations.
11. Produce update or final report.

7
CONCLUSIONS

This technical update report has described the first steps in a proposed multi-year EPRI project for development of technologies and design approaches for low-maintenance protection and control systems. The goals are:

- To research and ultimately specify new approaches and technologies for reducing the cost of maintaining protection systems;
- To develop condition monitoring approaches to improve protection reliability performance of protective relaying systems as maintenance cost is reduced;
- To base the new designs on actual user circumstances and needs as assessed through surveys, workshops, and presentations;
- To develop new P&C system designs which utilities can include in creating their own new maintenance programs with reduced cost and increased reliability.

The 2011 work has presented the principles to EPRI Task Force members in seminars and webinars. Chapter 2 presents a detailed documentation of the principles of protection system design based on condition monitoring. The Task Force has discussed and is tracking the development of the regulatory standard(s) as summarized in Chapter 5.

A key element of 2011 results is feedback from Task Force members through a detailed survey of protection system maintenance issues and approaches, presented in Chapter 3 and summarized in Chapter 4. Survey results will frame design specifications to be started in 2012.

While the project title focuses on cost reduction, there may be even more important benefits for utility members than savings of maintenance time and effort. Maintenance programs based on condition monitoring substantially reduce the risk of misoperations and damage caused by human error – a major cause of serious outages in recent utility industry history. They also reduce the risk of misoperations due to hidden failures that came about since the last time-based maintenance test – problems are detected and repaired as soon as they occur. Survey results show that there is plenty of work for available maintenance technicians – these design approaches will make technicians available for increasing volumes of needed capital upgrade work.

With the support of P&C task force, the project outcomes can also possibly influence the community of equipment vendors to supply products that include necessary functions and features for easier user implementation and documentation.

Finally, the report presents a roadmap for continuing development work through 2012 and 2013.

A
SURVEY DOCUMENT

The following presents the Survey Document as shared with Task Force members. Appendix B below shows the raw responses to survey questions.

The appearance of the following is modified in compliance with EPRI document formatting standards, but the content is identical to the original document.

Survey Questionnaire

P37.103 Development of Low Maintenance Protection and Control Systems

Rev. 2

Last Update: 06/20/2011

EPRI Project Manager: Yuchen Lu, ylu@epri.com, 704-595-2692

Principal Investigators: Eric Udren (Quanta Technology) and Yuchen Lu (EPRI)

Note: The responses of survey participants will be combined **WITHOUT** identifying individuals or companies. The survey results will be solely used for the EPRI project P37.103 and will not be shared with any third party.

<u>Explanation for respondents</u>

The EPRI project investigators seek:

- To understand today's protection system maintenance program approaches and issues.
- To share aggregated results with EPRI participants.
- To understand how to develop low-maintenance P&C designs that are useful and serve the real needs of the industry.
- To get feedback and suggestions that improve the program results.

In the flow of questions and discussion to follow, final Question 18 frames the low-maintenance P&C system program drivers for you, and seeks your specific feedback on how this approach might impact maintenance activities and organizations.

In all of the following, the investigators want the estimates, judgments, and honest feedback of EPRI utility experts, based on their experience with P&C maintenance. We are **<u>not</u>** asking for precise details or time consuming research. We are using an interview process to capture your responses and reduce your effort – or write answers if you prefer. Please feel free to ask your company colleagues about important points with which you have not had personal contact.

1. Please give a brief overview of your maintenance program for protective relays and communications systems used with protective relaying systems, **using the table at the end of this survey document**. Note that only high-level overview estimates are needed – no detailed maintenance program documents.
    a. What makes your maintenance program testing different from commissioning testing?
2. How is the testing work organized?
    a. Are there different categories of maintenance staff for relays versus communications?
    b. If you have any communication-assisted protection schemes, which group is responsible for the communications part?
    c. What work rules or union rule constraints impact how work programs are defined and assigned?
    d. Please describe your approach to sending staff to a particular station:
    e. To test all relays and/or communications in the station in one session?
    f. Or to test specific equipment for which they are trained and equipped?
    g. Or to test only items with approaching maintenance due dates?
    h. Or other approach to maintenance dispatch?
    i. How do maintenance personnel record the results of maintenance testing?
    j. Are specific test results kept?
    k. Is there any view of maintenance results across populations of similar devices?
    l. Is there an activity that detects population problems or trends?
3. What is your *estimate* of the *percentages* of protection and control maintenance staff *time* spent on:
    a. Repairs and troubleshooting with associated travel & overhead work.
    b. Routine scheduled maintenance testing with associated travel & overhead work.
    c. Other – please describe.
4. Can you provide an estimate of cost for maintenance testing for a typical microprocessor-based transmission line protection system (one of a redundant set, or all redundant sets – please specify)?
    a. How many different groups are involved?
    b. How many man-hours or man-days are required?
5. How are relay maintenance personnel trained, and kept up-to-date for skill sets?
    a. How are skills updated with new equipment or requirements?
    b. Do you have any live P&C panel simulators for training?
    c. Can you estimate the training/education cost per person per year?

6. Please describe your testing approach for microprocessor relays:
    a. What events trigger testing?
    b. For a protection scheme with multiple relays and communications links, do you test component relays, test full panels as functional units, test end-to-end, or some combination?
       Functional test – apply ac and status inputs to a complete panel or system and check for correct responses.
       End-to-end test – perform an overall functional test on a system whose parts are at separated locations – such as a functional test of a pilot transmission line relaying system using multiple test sets at each terminal having GPS test trigger coordination.
    c. How do you assure that the relay(s) can properly trip breakers?
7. Please describe your testing approach for relaying communications channels:
    a. Power line carrier
    b. DS0 or other TDM, on SONET or digital microwave
    c. Analog leased circuit or analog microwave
    d. Other
8. Please describe if or how you utilize the self-monitoring or self-testing capabilities of:
    a. Microprocessor relays
    b. Pilot protection channels – carrier
    c. Pilot protection channels – DS0, other TDM, on SONET or digital microwave
    d. Pilot protection channels – analog leased circuit or analog microwave
    e. Other channel or protection system component types
9. Are you using any data communications systems within substations (such serial or Ethernet data connections):
    a. To actually perform a high speed protective function like critical measurement or tripping?
    b. To monitor any part of a protection system?
    c. Others?
10. What has been your experience with self-monitoring?
    a. Do you use it to extend testing intervals?
    b. Any experience of undetected problems?
    c. Have you used monitoring to completely eliminate human testing on **any** items of equipment?
    d. How and where are alarms reported and acted upon?
    e. How is the alarming function tested?
11. How do you assure that microprocessor relay settings are correct during maintenance?
    a. What is the reference for “correct settings”?
12. What is your experience with protection system problems or misoperations induced by human errors during testing and maintenance activities?

13. What do you feel are the gaps or issues:
    a. In your protection system maintenance program or results?
    b. In your protection communications maintenance program or results?
    c. In the design of products you are maintaining?
    d. In the maintenance tools that are available?
    e. Other issues?
14. What are your testing approaches, intervals, and experiences with electromechanical auxiliary relays? (Define "auxiliary relay" as an electromechanical clapper or rotating contact device whose function is circuit isolation, contact multiplication, or operation latching. Examples are devices 86, 94, and 62. This does not include relays measuring analog quantities, such as solenoid current or voltage relays.)
    a. Auxiliaries in the tripping path.
    b. Auxiliaries in roles other than direct tripping.
    c. Lockout switches or multi-trips.
15. Do you analyze transmission relay operations when the overall protection operating result is what you expected?
    a. What data do you check?
    b. What data do you retain for future reference?
16. Give a brief overview of differences in protection system maintenance programs among bulk transmission, lower voltage transmission, and distribution systems.
    a. Time intervals
    b. Activities
    c. Use of microprocessor relays or monitoring.
17. How has your protection system maintenance program being changed as a result of regulatory reviews or audits imposed over the last five years?
18. The EPRI project associated with this survey aims to research and demonstrate how a protection and control system can be designed to make the most of the condition monitoring capabilities of protection system components, to reduce or possibly eliminate the bulk of requirements for periodic maintenance testing. This potentially offers the benefits of:
    a. Reduced time, effort, and cost of periodic maintenance.
    b. More complete coverage of the protection system.
    c. Failures are alarmed at once – no hidden failures waiting for discovery by infrequent testing or by a fault misoperation.
    d. Reduction in human error induced damage or misoperation.
    e. Technicians can focus their efforts where they will accomplish the most benefit.

However, this approach would change the way a utility runs its maintenance program:

a. Settings and configuration management becomes more important.
b. Technicians who are not performing frequent testing on reliable products will see their troubleshooting skills dull for these products – training on simulators becomes more important to insure readiness for fixing failures – more like training of system operators.
c. The components of self-monitoring systems (like communications links for local control) will require some new troubleshooting skills.

- What is your reaction to this initiative on protection and communications system design?
- How do you think others in your organization would react?
- What specifics would you like to see included?
- What advice or cautions do you offer to the project team?
- What do you think is needed to bring about acceptance of the results, assuming they are technically plausible?

End of the Survey – Table for Question 1 starts on following page.

Thank you for your participation!

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Protective Relays					
Electromechanical measuring relays					Examples: 21, 25, 27, 50, 51, 59, 87
Static relays					Generally multifunction.
Microprocessor relays					Generally multifunction.
Lockout relays/switches					Example: 86 (See question 14)
Auxiliary relays					Examples: 62, 94 (See question 14)
Communications for Protective Functions					
Power line carrier systems					
Data, SONET, or digital microwave					
Analog leased circuit or microwave, copper circuit					
In-substation Ethernet, network, or serial link communications					

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Station Dc Supplies					
Battery banks					
Charger and supply systems					
Voltage/Current Sensing Devices					
CTs					
PTs					
Control Circuitry for Circuit Breakers					
Trip coils (one or multiple coils)					
Other control circuitry between trip outputs and trip coils					

(End of Appendix A)

B
COMPILED SURVEY RESPONSES

The following presents the responses as received for each question in the survey.

Italicized entries were recorded by investigators in personal interviews. Entries in normal font were written by the respondents themselves.

Question 1

1. Please give a brief overview of your maintenance program for protective relays and communications systems used with protective relaying systems, **using the table at the end of this survey document**. Note that only high-level overview estimates are needed – no detailed maintenance program documents.

Responses appear in tables on following pages.

Respondent 1

Respondent 1 did not provide table information.

Other respondents' table results appear on following pages.

Table B-1
Respondent 2

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Protective Relays					
Electromechanical measuring relays	28000	3 years	Routine Maintenance	Periodic Time Intervals	
Static relays	2000	3 years	Routine Maintenance	Periodic Time Intervals	
Microprocessor relays	12000	6 years	Routine Maintenance	Periodic Time Intervals	
Lockout relays/switches	45000	N/A	Routine Maintenance	Not Required	
Auxiliary relays	100000	N/A	Routine Maintenance	Not Required	
Communications for Protective Functions					
Power line carrier systems					
Data, SONET, or digital microwave					
Analog leased circuit or microwave, copper circuit					
In-substation Ethernet, network, or serial link communications	100	None	None	None	
Station Dc Supplies					
Battery banks	300	Not Sure	Not Sure	Not Sure	
Charger and supply systems	600	Not Sure	Not Sure	Not Sure	

Table B-1 (continued)
Respondent 2

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Voltage/Current Sensing Devices					
CTs	Not Sure	Not Sure	Not Sure	Not Sure	
PTs	Not Sure	Not Sure	Not Sure	Not Sure	
Control Circuitry for Circuit Breakers					
Trip coils (one or multiple coils)	700	3 to 6 years – done during relay testing	Trip Tests	Periodic Time Intervals	
Other control circuitry between trip outputs and trip coils					

Table B-2
Respondent 3

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Protective Relays					
Electromechanical measuring relays	90%	2 yr		Time based or caused misoperation	
Static relays	1%	2 yr			
Microprocessor relays	9%	6 yr	More dynamic testing		
Lockout relays/switches					
Auxiliary relays					

Table B-2 (continued)
Respondent 3

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Communications for Protective Functions					
Power line carrier systems		Yearly	Adequacy testing	Routine testing	
Data, SONET, or digital microwave		The same as relays			Both dedicated and leased
Analog leased circuit or microwave, copper circuit					Analog has quite a lot of issues. Go digital
In-substation Ethernet, network, or serial link communications					Traditionally, no peer to peer communications. New design has this.
Station Dc Supplies					
Battery banks		Monthly, Quarterly			
Charger and supply systems		Monthly, three months, yearly load testing.			
Voltage/Current Sensing Devices					
CTs			Load reading/checks		
PTs			Load reading/checks		
Control Circuitry for Circuit Breakers					
Trip coils (one or multiple coils)					Dedicated device for monitoring of trip loop. Not using relay TCM.
Other control circuitry between trip outputs and trip coils					

Table B-3
Respondent 4

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Protective Relays					
Electromechanical measuring relays	3850	4 yr	Per manual		
Static relays	850	4yr	Per manual		
Microprocessor relays	4500	8 yr	I/O and A/D verifications and alarms		
Lockout relays/switches	950	4 yr	Operation check		
Auxiliary relays					
Communications for Protective Functions					
Power line carrier systems	670	4 yr	Level checks and alarms		
Data, SONET, or digital microwave					
Analog leased circuit or microwave, copper circuit	350	4 yr	Level checks and alarms		
In-substation Ethernet, network, or serial link communications					
Station Dc Supplies					
Battery banks	250	1 yr	Impedance test and visual inspection		
Charger and supply systems	250	1 yr	Voltage output tests and alarms		

Table B-3 (continued)
Respondent 4

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Voltage/Current Sensing Devices					
CTs	10,000		Verified with relay test		
PTs	4400		Verified with relay test		
Control Circuitry for Circuit Breakers					
Trip coils (one or multiple coils)	4000	None	Use TC monitors		
Other control circuitry between trip outputs and trip coils					

Table B-4
Respondent 5

<table>
<tr><th>Equipment category</th><th>Estimated Quantities</th><th>Test interval</th><th>General description of test</th><th>Trigger(s) for testing</th><th>Issues or comments</th></tr>
<tr><td colspan="6">Protective Relays</td></tr>
<tr><td>Electromechanical measuring relays</td><td>50%</td><td>4 yr</td><td>Test set program & some manual tests</td><td rowspan="5">Maximo work order for some.
Manual spreadsheet with intervals for others
More Maximo asset management integration planned</td><td></td></tr>
<tr><td>Static relays</td><td>10%</td><td>4 yr</td><td>Test set program & some manual tests</td><td>Working on replacement of relays</td></tr>
<tr><td>Microprocessor relays</td><td>40%</td><td>6 yr.</td><td>Automated test runs and plots circle</td><td>SEL, GE, Areva, ABB, Beckwith</td></tr>
<tr><td>Lockout relays/switches</td><td></td><td>2 yr.</td><td>During functional trip test</td><td></td></tr>
<tr><td>Auxiliary relays</td><td></td><td>2 yr.</td><td>During functional trip test</td><td></td></tr>
</table>

Table B-4 (continued)
Respondent 5

Equipment category	Estimated Quantities	Test interval	General description of test	Trigger(s) for testing	Issues or comments
Communications for Protective Functions					
Power line carrier systems		*1 yr.*	*Performance test*		*Manual checkback weekly or monthly.* *Guard monitoring*
Data, SONET, or digital microwave		*1 yr.*	*Performance test*		*SONET, microwave, dedicated fiber. Alarm performance where available*
Analog leased circuit or microwave, copper circuit		*1 yr.*	*Performance test*		*Require 2 to issue trip*
In-substation Ethernet, network, or serial link communications					*Not in use yet. Considering Mirrored Bits; GOOSE at one location.*
Station Dc Supplies					
Battery banks		*1 mo. + 5 yr. load test*			*Use spare batteries during load test*
Charger and supply systems			*Continuous ground alarm. Operator must look at voltage.*		
Voltage/Current Sensing Devices					
CTs		*With relays*			*No degaussing of CTs*
PTs		*With relays*			
Control Circuitry for Circuit Breakers					
Trip coils (one or multiple coils)		*2 yr.*	*Functional trip test through actual path. TC1 & TC2 tested separately*		*Dc monitor on every relay scheme. Some red light TCM on old schemes*
Other control circuitry between trip outputs and trip coils		*Relay testing interval*	*Remainder of scheme test*		*Not monitoring trip circuit in older schemes – starting with new designs based on data communications*

Question 1a

1. Program overview including tables
    a. What makes your maintenance program testing different from commissioning testing?

At the time of maintenance, the following tests are conducted:

- Compare relay settings against settings in protection information system
- Confirm no self-checks alarms exist. Confirm power supply and relay time.
- Isolate IED/relay – open all input and output switches on the rack
- Confirm health of all inputs and output contacts and interface wiring from input contacts
- Test all protection elements implemented in relays. Moving forward we plan to only test one element to verify integrity of operation. *Looking for hardware problems; functional test*
- Confirm in-service settings *(see first bullet)*
- Zone test trip - Confirmation from SER of all outputs – *including dc trip circuits. Old design included trip auxiliary module. Now this is done through a breaker IED*. Check measurements, breaker trip, pilot communications.*
- Test alarms to control center
- *Take relay metered value readings or electromechanical instrument and validate ac signals, with focus on polarity.*
- *Not end-to-end testing- blocking switch isolates from teleprotection, which is tested and dealt with separately.*

At the time of commissioning, the following tests are conducted:

- Confirm inputs from interfacing protection outputs to the inputs of new IED
- Confirm outputs from new IED output to interfacing protection *(breaker IED)* inputs
- Confirm analog inputs from links/fuses to isolation test switches for the new IED
- Test all protection elements according to settings provided, relay logic according to settings provided, contact inputs, contact outputs, alarms
- Simulate protection system operation to the interfacing protection zone input blocking switches and breakers
- *End-to-end testing performed here*

**Features of breaker IED*

- *Bring all auxiliaries and trip signals to one trip point*
- *Redundant A&B units*
- *BF, TCM, tripping outputs*
- *Can interrupt trip circuit – MOSFET trip module or trip interrupting accessory from vendor*
- *No lockout switches – multiple trips go to each of the breaker IEDs*
- *Wired connections. Using UR C60.*
- *View that IEDs are inexpensive*

Our Commissioning Testing requires more testing than the maintenance program. For our Microprocessor relays we test every element for commissioning testing. For maintenance testing we only test the tripping elements (i.e. 21 distance, 67 directional time overcurrent) using fault simulation tests. Fault simulation testing is method used to check the overall operation of a digital relay. These tests are performed with the relay cut-out but otherwise fully operational (no elements disabled and no output contacts altered.) Fault data (supplied from Aspen, fault recording devices, or manual calculation) is applied to the relay, then event analysis is used to determine correct relay operation. These types of tests also ensure that the settings are correctly applied and that the relay performs as the settings engineer expects.
Commissioning program is more comprehensive than the maintenance program. On commissioning, detailed positive and negative checks are performed. Typically, maintenance only involves positive checks.
CE [commissioning] testing is more thorough, maintenance testing is a “hand check” of the functionality of the systems
Commissioning: *No standard commissioning procedure* *Meggering CTs – not part of routine maintenance testing* *Panel wiring tests* *Maintenance tests:* *Standard maintenance testing procedures* *Functional testing* *Current & voltage, but no polarity check* *Often find multiple CT circuit grounds during tests* *Test relays with macros on Doble or OMICRON test set, and EnoServ testing database product.* *Problem with settings often found to be incorrect*

Question 2a

2. How is the testing work organized?
    a. Are there different categories of maintenance staff for relays versus communications?

This varies depending on the Field P&C/telecom group – usually each field P&C/telecom engineering group has certain specialized personnel who run commissioning, and preventative and corrective maintenance tests on either protection IEDs, or control equipment (gateways, RTUs, SCADA network Ethernet switches etc), or telecom equipment (IMUX, PLC, etc). However, a majority of the field P&C personnel in each area identified above are skilled in conducting maintenance and commissioning of all P&C/Telecom equipment. There is no preventative maintenance performed on non-protection communication equipment – routers, switches, etc. Relays are usually tested by relay technicians who are not the same as telecommunications technicians.
Yes, System Protection and Control (SPC) staff maintains the Protective Relays, and Power System Control (PSC) maintains communication equipment.
One group
Varies by contractor used
The same technicians do all work

i. If you have any communication-assisted protection schemes, which group is responsible for the communications part?

The Field P&C/telecom group is responsible for any maintenance of the communication-assisted protection schemes. The SONET equipment is continuously self-checked, and no maintenance is performed on this equipment; however IMUX, PLC, radios, tone equipment, etc are all put on a periodic maintenance cycle and maintained by the local Field P&C/telecom group. *Live data channels are clearly segregated from quiescent [non-operational] channels.* A central P&C/Telecom Technical Services group (*Help Desk*) provides support to the field P&C/Telecom engineering groups across [the service territory]. Within the P&C/Telecom Technical Services group, there are a number of specialists who provide support on specific types of equipment – protection relays/IEDs, control equipment (gateways, RTUs, etc), telecom equipment, and monitoring equipment (DFRs, SERs, etc)
Generally the PSC tests the communications paths and communication equipment and SPC tests the functionality (i.e. trip signal sent, trip signal received)
PST
Varies by contractor used
The same technicians do all work

ii. What work rules or union rule constraints impact how work programs are defined and assigned?

Unionized construction personnel are responsible for constructing new panels, and connecting wires between the protection, control and telecommunication systems, and the cables to the primary power system equipment. *(This is <u>just</u> for construction).*
See answers above
No specific union rules regarding the definition of the maintenance program other than the work must be done by the union workforce.
Varies by contractor used
(no answer)

Question 2b

b. Please describe your approach to sending staff to a particular station:

i. To test all relays and/or communications in the station in one session?

We don't typically do this. We have all protections on a periodic preventative maintenance cycle as required by NPCC and/or internal strategies. Each protection system maintenance is scheduled independently. However, if scheduling permits, one individual will perform all maintenance due at that location.
No
We test relays/communications associated with a single power system element in one session. We do not test everything in the station in one session. We use Maximo to track preventative maintenance work. Relay calibration can do online. Trip testing is off line.
Where possible, try to limit travel time
Test per scheme. Try to group test visits, but no formal process.

ii. Or to test specific equipment for which they are trained and equipped?

In each field P&C group, certain personnel may be dedicated to performing preventative/routine maintenance only, while other personnel may only focus on commissioning and corrective maintenance. In most groups, there are a one or two field technicians (or engineers) who perform all protection maintenance, and another one or two field technicians (or engineers) who perform all telecom maintenance. In some other regions [of the service territory], preventative maintenance is done by whoever is available/scheduled for the work.
Not really, SPC Craftsman trainees are allowed to test equipment that they have training on; however they are required to be supervised by a full craftsman.
(no answer)
(no answer)
(no answer – covered above)

iii. Or to test only items with approaching maintenance due dates?

This is our maintenance strategy.
Yes this is our primary approach to maintenance testing. In addition to meeting maintenance dates testing schedules for EHV voltage equipment must be submitted at least 45 days in advance to the planners and schedulers so they can run system studies and approve the testing scheduled. Often test schedules are sent up to 6 months in advance for this equipment.
yes
mainly to test by test due dates
(no answer – covered above – by test schedule)

iv. Or other approach to maintenance dispatch?

For corrective maintenance, whoever is "on-call "has to troubleshoot all protection, control or telecom failures. Hence a majority of personnel in each field P&C group are skilled in troubleshooting all protection, control and telecom equipment deployed in their area; some personnel may be more skilled in troubleshooting one type of equipment as opposed to another.
See above answer to iii.
(no answer)
(no answer)
(no answer – covered above)

Question 2c

c. How do maintenance personnel record the results of maintenance testing?

i. Are specific test results kept?

Yes. Specific test results are retained. We keep these test results for 2 maintenance cycles to demonstrate the cycle.
Test programs record the results and they stored according to a file format standard.
Relay calibrations are recorded using Doble ProTest. Trip tests are recorded on "template" sheets that visually depict the relay and LOR I/O.
Yes, electronically
Relay test set records, or handwritten. Sites vary – some scan and submit electronic records; some file paper. Some scan results into Maximo asset management system. Maximo keeps the record that the test was done.

ii. Is there any view of maintenance results across populations of similar devices?

Defect reports are written for protection failures. We do not have a clear view of all maintenance results yet, but we have been moving our maintenance scheduling and reporting to SAP and hope to be able to extract such reports. *Do have deficiency reporting system – asset managers can get high level results, and should be doing this. They do know if there is a serious problem.*
The capability is there however more issues identify themselves during miss-operations rather than maintenance testing. Because testing is automatically recorded as pass or fail. All failures must be addressed and explained.
It would have to be a manual search of ProTest results
review 10% of tests
(no answer)

iii. Is there an activity that detects population problems or trends?

These trends are observed by the sustainment program managers and the centralized P&C/Telecom services groups.
The testing itself is the activity. Equipment passes or fails a test. All failures are addressed and investigated. Failures are addressed right away not allowing for trends to really development. As soon as we see more than one piece of equipment suffer from the same failure, we start working with the manufacture to resolve the failure.
At a high level we track misoperations according to relay models and target the most problematic models for replacement
Yes.
For problematic relays, we accelerate the rate of testing. This is not according to a precise system.

Question 3

3. What is your *estimate* of the *percentages* of protection and control maintenance staff *time* spent on:
    a. Repairs and troubleshooting with associated travel & overhead work.

10%?
15 – 20%
33%
25% mostly troubleshooting
20%

b. Routine scheduled maintenance testing with associated travel & overhead work.

20%?
40- 60%
33%
75%
80% including small issues corrected on the spot

c. Other – please describe.

Miscellaneous – 10%? Commissioning – 60%? *Busy with sustainment program – E/M replacements – and wind farm interfacing* The time spent by each field P&C/Telecom engineering group on preventative/periodic maintenance, corrective maintenance and commissioning is tracked. *There is no question that we need to reduce the amount of maintenance. What can we cut out?*
20 – 45%
Capital upgrades – 33%
(no answer)
0%

Question 4

4. Can you provide an estimate of cost for maintenance testing for a typical microprocessor-based transmission line protection system (one of a redundant set, or all redundant sets – please specify)?

Numbers below are for 1 line protection relay (1 of redundant set) at one of the terminals.
Redundant Set $500
(no answer)
Roughly one hour per relay. 8 man hours for relays with communication per scheme (2 ends).
Not sure of numbers, but there should be big savings from CBM. Technician time is precious and hard to get. We need manpower for upgrades – upgrades get penalized by testing.

a. How many different groups are involved?

For distance and differential protections, only 1 field technician/engineer would be needed. Transfer trip or other inter-station commands are verified to the teleprotection input blocking switch. Teleprotection signaling between stations is verified on an independent maintenance cycle.
Two Groups – field Operators and Field Craftsman
One group for battery maintenance, another group for relays, CT/PT, communications and control circuitry
(no answer)
(no answer)

b. How many man-hours or man-days are required?

14 man-hours - includes testing, driving (in most cases) to site, recording results, etc
4 to 8 hours not including drive time. Drive time ranges 10 minutes to 6 hours one way
Trip check 16*6 hrs; calibration: one week
(no answer) *From above - Roughly one hour per relay. 8 man hours for relays with communication per scheme (2 ends).*
(no answer)

Question 5

5. How are relay maintenance personnel trained, and kept up-to-date for skill sets?

P&C Tech Services provides this training – procedures, test sheets, and initial training. *Mostly internal courses and teachers.*
SPC Craftsman generally have at least a two year associates degree, power system experience in another trade (i.e. operator or electrician) and a four year on the job training with biannual steps. They are kept up to date with in house training in the central office, and e-mail alerts.
Continuing formal training program and OJT.
(no answer)
Every site supervisor schedules training. They communicate with central training management for logging of training.

a. How are skills updated with new equipment or requirements?

All field P&C/Telecom engineers and technicians attend a multi-year training program. This program consists of courses that have both a theory component as well as a lab component; some foundational courses are required, and a number of electives are offered for each type of relay, RTU, teleprotection equipment, etc. The centralized P&C/Telecom support group puts together maintenance/ commissioning documents and standardized test sheets to help field engineers commission and troubleshoot new equipment.
They are kept up to date with in house training in the central office, and email alerts.
(no answer)
(no answer)
New relay – a few days of technician training. Engineers go to sites to help technicians and develop test plans.

b. Do you have any live P&C panel simulators for training?

The simulators are all located at the central training center where all field P&C/telecom engineers and technicians train. These are used for the training program that all new field P&C/telecom engineers have to attend, and for elective courses offered at this training center.
No.
Yes
(no answer)
No simulators now, but will start this for new IEC 61850 approach. Asking for spare relays for labs.

c. Can you estimate the training/education cost per person per year?

$15,000 - $20,000/year for the first 4-8 years
$10k
Roughly $7k per year for the formal training
(no answer)
Two to three weeks per year, partially on the job. Note that these technicians handle many other types of equipment besides relays.

Question 6

6. Please describe your testing approach for microprocessor relays:
   a. What events trigger testing?

• When any changes are made to settings/logic, selective relay testing is performed. • The protection relay is tested on its periodic maintenance cycle. • Potential protection system misoperation investigations
Routine maintenance is based on a time interval. Testing is also ‘triggered’ by whole relay or component replacement, configuration change, or firmware change.
Time based
Time based : cascade
Test end-to-end as well as testing of individual relays.

b. For a protection scheme with multiple relays and communications links, do you test component relays, test full panels as a functional unit, test end-to-end, or some combination?
Functional test – apply ac and status inputs to a complete panel or system and check for correct responses.
End-to-end test – perform an overall functional test on a system whose parts are at separated locations – such as a functional test of a pilot transmission line relaying system using multiple test sets at each terminal having GPS test trigger coordination.

The entire protection scheme is tested; this scheme may comprise of multiple relays (auxiliary relays, etc), which will all be tested as part of this scheme. The transfer trip and other teleprotection commands are tested to the teleprotection equipment blocking switches, when testing communication based protections.
New relay commissioning includes component testing, functional testing, and end-to-end testing. Routine maintenance is functional testing
Combination. We test the relays as components, then we do a full functional test on the protection scheme including end to end testing.
Maintenance by individual unit
Test end-to-end as well as testing of individual relays.

c. How do you assure that the relay(s) can properly trip breakers?

Every 4 (sometimes 6) years, we confirm that the breakers can be tripped by the protections. These tests can be done at the time of IED maintenance or independently as zone test trips initiated by the protections
Trip Checks are performed at the end of the relay maintenance testing.
By closing the breakers and tripping them from the relays
Check tripping voltage at relay contacts.
(no answer)

Question 7

7. Please describe your testing approach for relaying communications channels:
   a. Power line carrier

DCB – more often – on/off check. *Not automatic checkback – manual test 1 to 3 months* FSK – shifting power and freq – specific test. *Guard monitoring, plus annual test*
not applicable
Yearly signal adequacy test. Monthly test on ON/OFF type
Level checks and adjustments as necessary
(no answer)

   b. DS0 or other TDM, on SONET or digital microwave

Self-monitoring
(no answer)
Digital circuits on constantly monitored and alarmed, therefore, we do not perform periodic testing
(no answer)
(no answer)

   c. Analog leased circuit or analog microwave

We do not use analog microwave anymore. Will confirm if we key to check analog leased circuits for maintenance, and what self-checking is employed.
(no answer)
Yearly adequacy test
level checks
(no answer)

d. Other

(no answer)
(no answer)
Pilot wire. Thru-line calibrations performed with HCB relay calibration
(no answer)
(no answer)

Question 8

8. Please describe if or how you utilize the self-monitoring or self-testing capabilities of:
   a. Microprocessor relays

We use all the available self-checking features implemented in our IEDs. Any internal failure mode that is self-checked is alarmed to our operators via SCADA. *There is confusion about what failure modes are checked and what the variation is among vendors. Can this be standardized?*
Outputs of the relays are hardwired to the SER/SCADA system describing either a minor relay alarm failure or major relay alarm failure
critical failure contacts are wired to station annunciator
alarm to EMS
Wire alarm contact to SCADA

   b. Pilot protection channels – carrier

Guard signals are sent to monitor channel health)
carrier N/A
Alarm on loss of guard, or checkback failure.
alarm to EMS
Channel alarms – major or minor as provided by manufacturer

c. Pilot protection channels – DS0, other TDM, on SONET or digital microwave

Find out – continuously monitored. *Performance – BER or SNR. Goes to a separate monitoring center.*
(no answer)
alarm on loss of digital communications
(no answer)
(no answer)

d. Pilot protection channels – analog leased circuit or analog microwave

monitored
(no answer)
Alarm on loss of guard.
alarm to EMS
(no answer)

e. Other channel or protection system component types

monitor channel integrity
(no answer)
Pilot wire- alarm on loss of 1mA monitoring current or ground/short detection
(no answer)
(no answer)

Question 9

9. Are you using any data communications systems <u>within substations</u> (such serial or Ethernet data connections):
    a. To actually perform a high speed protective function like critical measurement or tripping?

No
No
We use SEL-2505 with mirrored bits for tripping in a few stations. We have a upcoming project in which we will use GOOSE for tripping over an internal Ethernet network
(no answer)
IEC 61850 GOOSE used for everything – runs out to breaker. Big question of how to test GOOSE messaging points.

    b. To monitor any part of a protection system?

Alarms from IEDs.
No
We have several stations in which we use an Ethernet network for alarm and SCADA data
(no answer)
Can we use 61850 logical nodes for this? What gaps exist? Can we have a standard reporting mechanism?

    c. Others?

We use Ethernet connections to retrieve telemetry, alarms, SCADA Standalone DFR/SER data via serial IED DFR/SER moving to Ethernet based *For CIP, plugs were pulled. New multi-year project developing operational WAN architecture & central database – one network for relays and DFRs.*
(no answer)
(no answer)
(no answer)
(no answer)

Question 10

10. What has been your experience with self-monitoring?

a. Do you use it to extend testing intervals?

Yes
No
no
no
No – 6 years is based on NPCC recommendations – but experience has been good

b. Any experience of undetected problems?

A vendor's relay was tested in a lab – blew up input transformer but produced no alarm
No
(no answer)
no
Transf/bus diff – dead phase produced no alarm. Rebooted the relay – then got an alarm. Have seen this problem several times with this vendor's relay.

c. Have you used monitoring to completely eliminate human testing on **<u>any</u>** items of equipment?

SONET (completely eliminate)
No
no
no
No

d. How and where are alarms reported and acted upon?

The alarms are reported via DNP to the station gateway which then interfaces with the EMS. Depending on the criticality of the alarm, field P&C is dispatched.
SER and SCADA Alarms
Alarms are activated on the station annunciator where the local operator will take action. The station annunciator also sends category alarms to the main control center.
24/7 operations control center
Local annunciator connects to SCADA. A few manned stations have lights that operator checks.

e. How is the alarming function tested?

Alarms for conditions or failures monitored by the IED are tested at the time of maintenance. The IED self-checking alarms generated by the IED are not tested during maintenance. Fail-safe
Alarms are often tested as part of routine maintenance although this is a preferred practice and not a requirement.
During relay functional tests, folder location with archived file
During maintenance testing of the relays or communications systems.
At relay maintenance time

Question 11

11. How do you assure that microprocessor relay settings are correct during maintenance?
    a. What is the reference for "correct settings"?

The settings contained in our protection and control settings management system are always considered the master copy/ correct settings. In addition to being the repository for all our protection and control equipment settings and configurations, this system is also used for publishing, reviewing, and managing settings changes (manages protection relay setting lifecycle)
During the installation testing all relay elements that are enabled are tested as well as configuration logic. During Maintenance testing, we use fault simulation testing to check the tripping elements. Configuration logic testing only occurs if there has been a configuration change since the last maintenance or since it was installed. Settings are compared to a "Master" settings sheet maintained by the settings engineers.
File comparison with archived file
Verification with records
As-left settings used by technician, who may change them for test. Use compare feature to validate. New database is work in progress and will be the basis for comparison. Always upload settings to Aspen Database to be sure of having a record.

Question 12

12. What is your experience with protection system problems or misoperations induced by human errors during testing and maintenance activities?

A high ratio of our inadvertent/misoperations occur during periodic preventative maintenance.
They happen on occasion.
It happens. Need to simplify the maintenance process to reduce risk of human error.
Human error is a substantial cause in the number of misoperation >50%
Yes. Case of contractor that remapped fault detector to BF retrip & forgot to restore setting – didn't do compare. Later, tripped for a fault 4 stations away. Cases of opening the wrong test blade. Really understand this issue.

Question 13

13. What do you feel are the gaps or issues:

a. In your protection system maintenance program or results?

Compiling meaningful statistics on failures detected for preventative and corrective maintenance. Understanding all failure modes that are annunciated and what modes remain undetected.
Lack of equipment standard. SPC staff is expected to know everything from electro-mechanical to state of the art technology.
Reliance on folder structure for keeping data
no
Working on database; having uniform M&T for the whole organization; variety of tools (EnoServ, Doble, Omicron…)

b. In your protection communications maintenance program or results?

Compiling meaningful statistics on failures detected for preventative and corrective maintenance Understanding all failure modes that are annunciated, and what modes remain undetected
Not sure
(no answer)
no
Monitoring, trip testing, uniform test procedures – but doing a pretty good job here!

c. In the design of products you are maintaining?

More detailed identification of gaps in self-monitoring
The designs do not always follow the standard. Also they evolve over time.
Software bugs in microprocessor relays that lead to unpredictable behavior
no
61850 – 90 panels and 250 relays – how to maintain and test? Test switches?

d. In the maintenance tools that are available?

(no answer)
I would say tools are adequate.
(no answer)
no
Good in general, but what about 61850?

e. Other issues?

(no answer)
(no answer)
(no answer)
(no answer)
Sometimes an operator error shows that there is a problem.

Question 14

14. What are your testing approaches, intervals, and experiences with electromechanical auxiliary relays? (Define "auxiliary relay" as an electromechanical clapper or rotating contact device whose function is circuit isolation, contact multiplication, or operation latching. Examples are devices 86, 94, and 62. This does not include relays measuring analog quantities, such as solenoid current or voltage relays.)

    a. Auxiliaries in the tripping path.

Tested with the primary relay (94 relays) Trip module aux relays (collection) with multiple redundant contacts – only tested as part of ZTT
Trip checks are performed to the relays while they are cutout. For example it will be verified that a Breaker Failure relay will trip the Lockout relay while it is cut out but the lockout will not be verified that it trips the breakers it is connected too.
Include these in functional checks
none
Include in protection system tests. Sometimes aux relay problems are fixed on the spot.

b. Auxiliaries in roles other than direct tripping.

No maintenance done on contact multipliers, etc
Generally only on installation and not maintenance.
Usually included in functional checks
none
Include in protection system tests. Sometimes aux relay problems are fixed on the spot.

c. Lockout switches or multi-trips.

Not used
See answers to a and b
Include these in functional checks
4 yrs, only one device, only one coil, need to ensure they are exercised. Have not found any that do not operate in the last 8 years of testing
Include in protection system tests. Sometimes aux relay problems are fixed on the spot.

Question 15

15. Do you analyze transmission relay operations when the overall protection operating result is what you expected?
    a. What data do you check?

Yes all protection operations are analyzed. Based on the SCADA, SER and DFR data before, during and after the protection operation(s), the protection system behavior is evaluated, and categorized as either correct/expected operation or misoperation
Relay Event Reports, SER Reports, and when available DFR Reports.
Yes, DFR/SER, relay records, PI records, etc
The entire event report
Yes, for all BES operations and most others. Look at oscillographic data, SOE, within 10 days. Sometimes we find problems. Sometimes an apparent misoperation is found to be correct.

b. What data do you retain for future reference?

The DFR/SER data as well as the protection operation assessment/report is retained
Everything is archived.
same
(no answer)
(All data retained)

Question 16

16. Give a brief overview of differences in protection system maintenance programs among bulk transmission, lower voltage transmission, and distribution systems.

    a. Time intervals

Every 4-6 years, depending on self-monitoring employed
EHV – 60 months for microprocessor relays and 36 months for non-microprocessor relays
Time intervals are shorter for bulk than for non-bulk for EM relay. Same for microprocessor
We are Transmission only
Switchgear gets less maintenance activity. Combined cycle plants get more attention.

b. Activities

All maintenance items discussed above
(no answer)
same
(no answer)
Varies by site. Settings are performed by vendor of equipment – new settings only when relay is replaced.

c. Use of microprocessor relays or monitoring.

(no answer)
(no answer)
same
(no answer)
(no answer)

Question 17

17. How has your protection system maintenance program being changed as a result of regulatory reviews or audits imposed over the last five years?

The use of self-monitoring has allowed for extending of maintenance cycles
The main changes we are implementing as a result of the audit process are documentation requirements. We have begun using a central storage location for maintenance records.
More frequently before than today
no
Eliminated meggering and other unnecessary activities. Will adapt to PRC-005-2.

Question 18

18. The EPRI project associated with this survey aims to research and demonstrate how a protection and control system can be designed to make the most of the condition monitoring capabilities of protection system components, to reduce or possibly eliminate the bulk of requirements for periodic maintenance testing. This potentially offers the benefits of:
    a. Reduced time, effort, and cost of periodic maintenance.
    b. More complete coverage of the protection system.
    c. Failures are alarmed at once – no hidden failures waiting for discovery by infrequent testing or by a fault misoperation.
    d. Reduction in human error induced damage or misoperation.
    e. Technicians can focus their efforts where they will accomplish the most benefit.

However, this approach would change the way a utility runs its maintenance program:

f. Settings and configuration management becomes more important.

g. Technicians who are not performing frequent testing on reliable products will see their troubleshooting skills dull for these products – training on simulators becomes more important to insure readiness for fixing failures – more like training of system operators.

h. The components of self-monitoring systems (like communications links for local control) will require some new troubleshooting skills.

- What is your reaction to this initiative on protection and communications system design?

We are very interested in investigating these potential benefits of using smart technologies for protection, control and telecommunications. More monitoring to extend or potentially eliminate periodic maintenance
This is a wonderful thing to research. As we face the upcoming changes to NERC PRC-005 we will all be looking at ways to alleviate the added burden placed on our time. Plus we are having increasing difficulty in getting qualified technicians to perform maintenance so reducing the maintenance requirements (if done for the right reasons) could be a good thing.
I believe it is a good initiative
I agree with the approach
Agree with the approach – needed and helpful

- How do you think others in your organization would react?

While there will be a steep learning curve when it comes to embracing new technologies such as IEC61850, we believe that we can equip our field personnel with the right training and tools to help ease the transition.
This is initially going to be an unpopular idea especially with our technicians and those with a lot of experience.
Some may be concerned that longer maintenance intervals will lead to a reduction in staff
They would concur
This would help a lot. We are losing troubleshooting skills and on-site personnel.

- What specifics would you like to see included?

We are very interested in finding out which components or subcomponents of a 61850 based SAS are self-monitored by each IED, Ethernet switch, etc. Additionally we would like to know more about what system-wide self-monitoring features can be implemented at a station, and what failure modes of a 61850 based SAS are not self-monitored by any component self-monitoring or customized system-level self-monitoring. Within the IED itself vendors must be more specific about what failures may NOT be detected as well.
A/D converters and I/Os are typically not self monitored by the relays. If one of the goals of this project is to reduce maintenance we need a way to verify these components.
CT/PT monitoring
(no answer)
(no answer)

- What advice or cautions do you offer to the project team?

Extensive discussions and studies may need to be conducted to evaluate hidden failure modes that may not be detected by self-monitoring functionality developed by various P&C/networking equipment vendors. Additional system-level self-checking features/applications may need to be developed to provide the desired monitoring functionality, or provide overlapping self-monitoring.
Stay practical. The information that comes from this project needs to fit in with existing equipment and system designs. It would be great if we could replace all existing protection equipment tomorrow but that is never going to happen. Also stay away from ‘cutting edge’ technology as much as possible. We continually struggle with vendors that promise certain capabilities and then fail to deliver or fail to meet deadline after deadline. Better yet focus on proven technology.
Include a financial analysis that may be helpful in convincing regulators to permit funding of the necessary capital upgrades
(no answer)
(no answer)

- What do you think is needed to bring about acceptance of the results, assuming they are technically plausible?

(no answer)
One of the keys to acceptance is going to be NERC approval/ acknowledgement. Another thing that would help people accept this concept is statistics on things like: how these relays fail, how these failures are typically detected, how many errors are caused by over maintaining, etc.
Specific examples and case studies of detection of previously hidden problems.
(no answer)
(no answer)

Export Control Restrictions

Access to and use of EPRI Intellectual Property is granted with the specific understanding and requirement that responsibility for ensuring full compliance with all applicable U.S. and foreign export laws and regulations is being undertaken by you and your company. This includes an obligation to ensure that any individual receiving access hereunder who is not a U.S. citizen or permanent U.S. resident is permitted access under applicable U.S. and foreign export laws and regulations. In the event you are uncertain whether you or your company may lawfully obtain access to this EPRI Intellectual Property, you acknowledge that it is your obligation to consult with your company's legal counsel to determine whether this access is lawful. Although EPRI may make available on a case-by-case basis an informal assessment of the applicable U.S. export classification for specific EPRI Intellectual Property, you and your company acknowledge that this assessment is solely for informational purposes and not for reliance purposes. You and your company acknowledge that it is still the obligation of you and your company to make your own assessment of the applicable U.S. export classification and ensure compliance accordingly. You and your company understand and acknowledge your obligations to make a prompt report to EPRI and the appropriate authorities regarding any access to or use of EPRI Intellectual Property hereunder that may be in violation of applicable U.S. or foreign export laws or regulations.

The Electric Power Research Institute Inc., (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

Together…Shaping the Future of Electricity

1021915

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com