

Protective Relays

Numerical Protective Relays



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Protective Relays

Numerical Protective Relays

1009704

Final Report, December 2004

EPRI Project Manager
J. Sharkey

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Nuclear Maintenance Applications Center (NMAC)
EPRI
1300 W. T. Harris Boulevard
Charlotte, NC 28262

Principal Investigator
J. Sharkey

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REPORT SUMMARY

Protective relays are decision-making elements in the protection scheme for electrical power systems. Numerical relays offer many advantages over the traditional electromechanical types of devices. This guide provides an overview of numerical relays and discusses maintenance and testing.

Background

Protective relays monitor circuit conditions and initiate protective action when an undesired condition is detected. Protective relaying serves many functions including isolating faulted circuits or equipment from the remainder of the system so that the system can continue to operate. This function limits damage to faulted equipment and, therefore, reduces the possibility of fire or damage to adjacent equipment and minimizes hazards to personnel. It is imperative that protective relays function correctly in response to undesirable conditions. Numerical relays are microprocessor-based versus electromechanical. Therefore, reliability is greatly improved, while less maintenance is necessary and no calibration is required. Numerical relays improve operations and provide innovative solutions that simply were not possible with previous generations of protective relays.

Objectives

- To provide a clear understanding of relay schemes and considerations in the application and maintenance of numerical protective relays
- To provide plant maintenance, engineering, and operations personnel with knowledge and guidance on how to develop adequate tests, calibration, and post-installation and post-maintenance testing

Approach

EPRI's Nuclear Maintenance Applications Center (NMAC) reviewed numerical relays and compared their application in nuclear power plants to traditional electromechanical relays. Industry personnel and relay manufacturers were used to determine the advantages and potential pitfalls of numerical relay applications. The same sources were consulted to highlight differences in maintenance and testing requirements.

Results

This report provides a general overview of protective relays and the specific application of numerical relays. It familiarizes readers with the key components and subassemblies used in numerical relays and reviews fundamental operating principles. The report discusses protective relay design and construction features, the various types of numerical relays available, and protective relaying application concepts.

This guide also presents numerical relay reliability and security information to establish a baseline from which maintenance practices can be linked to a degradation mechanism or failure mode. Information on visual inspections, checks, and electrical tests are provided along with an overview of maintenance practices.

EPRI Perspective

In 1993, EPRI published *Protective Relay Maintenance and Application Guide* (NP-7216). This document outlined application considerations and maintenance practices for electromechanical relays.

Although electromechanical relays are still the most predominant relays in use in U.S. power plants, technological advancements and the risk of obsolescence are strong motivators for upgrading. It is inevitable that power plants will slowly move toward newer technology. In fact, this movement toward the use of digital/numerical type relays has already begun. At the time this document was published, one U.S. nuclear plant had already installed digital relays, and two other nuclear utilities were considering digital relays for selected applications.

This document was developed to assist plants with their understanding of digital/numerical protective relay technology, to provide application guidance, and to outline basic maintenance practices.

Keywords

Digital relay

Maintenance

Numerical relay

Relay

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William Bruce	Framatome ANP
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Steve Edwards	Siemens
Donald McHugh	Siemens
Juergen Holbach	Siemens
Brent Duncan	Siemens
Richard Preston	Siemens
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1

INTRODUCTION

Protective relays have a reputation for providing reliable service for many years. Nonetheless, protective relays are delicate instruments that are susceptible to the degradation of components that may affect performance. Due to their design, numerical relays have eliminated the degradation that can be expected from the mechanical components of electromechanical relays. Numerical relays also use minimal electronic components when compared to electronic relays. The failure of a protective relay to contain and isolate an electrical problem can have severe plant-wide repercussions. When an expected protective action does not occur, the end result of an electrical abnormality may be catastrophic equipment damage and prolonged downtime instead of localized minor damage. Because of the severe consequences of a failure, protective relays should be maintained in a high state of readiness. Critical applications should be carefully evaluated for redundant protection.



Key O&M Cost Point

Numerical relays have eliminated the degradation that can be expected from the mechanical components of electromechanical relays.

1.1 Background Information

Protective relaying is an integral part of any electrical power system. The fundamental objective of system protection is to quickly isolate a problem so that the unaffected portions of a system can continue to function. Protective relays are the decision-making device in the protection scheme. They monitor circuit conditions and initiate protective action when an undesired condition is detected. Protective relays work in concert with sensing and control devices to accomplish this function. There are several reasons to use protective relaying:

- To provide alarms when measured process limits are exceeded, thereby allowing operators an opportunity to intervene with corrective actions
- To isolate faulted circuits or equipment from the remainder of the system so that the system can continue to function
- To limit damage to faulted equipment
- To minimize the possibility of fire or catastrophic damage to adjacent equipment
- To minimize hazards to personnel
- To provide post-fault information to help analyze the root cause

Introduction

Under normal power system operation, protective relays remain idle and serve no active function. However, when required to operate because of a faulted or undesirable condition, it is imperative that the relays function correctly. Another point of concern is the undesired operation of a protective relay during normal plant conditions or tolerable transients. Inadvertent relay operation can result in unnecessary system or plant downtime. A maintenance and surveillance program will help to ensure that the protective relays respond properly to normal and abnormal conditions. This frequency of testing can be extended to longer periods than electromechanical devices. The number of tests can also be reduced due to the design and construction of the relays.

An effective maintenance program for protective relays accomplishes two primary goals. First, it provides a high degree of confidence that the electrical power protection system will respond to abnormal conditions as designed. Periodic assurance that protective relays are in an operable status is particularly important. Relay problems are generally detected by internal test routines and during operational checks via a human machine interface (HMI). Secondly, an effective maintenance program preserves the relay's readiness and helps to counteract normal and abnormal in-service deterioration that can affect a relay's electronic components over time. Even under normal conditions, electrical, thermal, and environmental stresses are continually at work, slowly degrading the relays. This deterioration is much slower in numerical relays than in electromechanical relays because numerical relays are not affected by mechanical deterioration. Routine maintenance checks help to identify any of the deterioration in the device. The life of numerical relays cannot be prolonged by recalibration, cleaning, and general maintenance because numerical relays are either functional or not. Failed devices must be removed, repaired, and/or replaced. Failed devices or device components such as printed circuit boards should be sent to the supplier for repair.



Key Technical Point

Deterioration is much slower in numerical relays than in electromechanical relays because numerical relays are not affected by mechanical deterioration.

1.2 Scope

The maintenance practices discussed in this report pertain primarily to numerical protective relays. Maintenance activities for single-function solid-state relays are not within the scope of this guide.

1.3 Document Overview

Section 1 of this report provides an introduction to the guide and highlights the key aspects of protective relay maintenance.

Section 2 provides a general overview of protective relays. It is intended to set the stage for more detailed information presented later in the guide. A typical protective relay operating sequence is reviewed to provide a more intuitive understanding of how a protective relay works. Section 2 also covers relay classification, designation, and terminology in considerable detail. Functional

designations and terminology can be confusing because of overlapping and sometimes conflicting reference standards. The information presented here should help to clarify any points of confusion or potential ambiguity.

Section 3 familiarizes readers with the key components in numerical multifunctional protective relays and reviews the operational functionality of the components. Although many different types of protective relays exist, they share similarities in design and operation. Typical design and construction features are covered in Section 3.

Section 4 builds on the fundamentals presented in Section 3 and discusses the many different types of protective relay functions that are available in the numerical multifunctional relays. This section is intended to familiarize readers with protective relay applications and to review the fundamental operating principles of the protective functions. The protective relays most often used at power generating plants are emphasized and discussed.

Section 5 describes design and application concepts used in numerical multifunctional protective relaying systems. Information presented in this section will help the user develop general design philosophies and application strategies that most fully exploit the innovative capabilities of numerical relay technology in both new construction and retrofit situations. These concepts will also contribute to the design of effective numerical relay maintenance strategies.

Section 6 provides information on how maintenance can be classified. It provides an overview of checks, inspections, and tests that can be performed on these devices. Maintenance practices and the determination of maintenance intervals are also discussed.

Section 7 provides information on how to remove a numerical relay from service. The information contained in this section is intended to provide a framework or baseline for establishing a successful removal procedure.

Section 8 provides information on electrical tests and calibration checks that can be performed on numerical relays. Because the requirements for numerical devices are vastly different from what was required to test electromechanical relays, test equipment is also discussed.

Section 9 provides information on numerical relay maintenance guidelines and considerations. This information is intended to help generating stations establish their protective relay maintenance practices. Section 9 provides information on maintenance philosophies, program objectives, and general considerations. Training requirements are also discussed in this section.

Section 10 provides information on failure modes and mechanisms that can affect numerical relays in the field.

Section 11 includes information on the self-diagnostic features found on numerical relays. These features provide essential maintenance information that was not possible on electromechanical relays. The self-diagnostic feature helps to limit human intervention to prove the functional operability of a protective relay.

Introduction

Section 12 provides information on the operational and fault information available on numerical relays. This information includes event, measurement, annunciation, fault and wave form data, and elements required to perform speedy and accurate commissioning and fault analysis.

Section 13 describes the features and functions typically provided in numerical relays that can monitor devices connected to the protection device, including monitoring of a coil or a fuse.

The report appendices also contain valuable information. Appendix A lists references for the guide. Appendix B provides a glossary of terms.

Appendix C provides an overview of the most important industry standards relating to protective relays. These standards are taken from the Institute of Electrical and Electronics Engineers (IEEE), the American Nuclear Society (ANSI), the National Fire Protection Association (NFPA), and the National Electrical Testing Association (NETA). This appendix serves as a road map for researching specific areas of interest.

Appendix D contains a list of electrical equipment device function numbers. Device function numbers are used extensively in documents relating to relay design, application, and testing. Device function numbers are referenced frequently throughout this report.

1.4 Key Points

Throughout this guide, key information is summarized in *key points* defined as bold lettered boxes that succinctly restate information covered in detail in the surrounding text, making it easier to locate.

By emphasizing vital information, key points enable personnel to take action for the benefit of their plant. The information included in these key points was selected by (NMAC) personnel, consultants, and utility personnel who prepared and reviewed this report.

The three categories of key points are operations and maintenance (O&M) cost, technical, and human performance. Each category has an identifying icon, as shown below, that draws attention to it, making it easy for personnel to quickly locate vital information.



Key O&M Cost Point

Emphasizes information that will reduce purchase, operating, or maintenance costs.



Key Technical Point

Targets information that will lead to improved equipment reliability.

**Key Human Performance Point**

Denotes information that requires personnel action or consideration in order to prevent injury or damage or to ease completion of the task.

Appendix E contains a listing of all key points in each category. The listing restates each key point and provides reference to its location in the body of the report. By reviewing this listing, users of this guide can determine if they have taken advantage of key information that can benefit their plants.

2

NUMERICAL RELAY DESCRIPTION

2.1 Purpose of Protective Relaying

The primary purpose for installing protective relaying remains unchanged since the relays were first introduced—to provide fast and selective clearing of faulted equipment or lines connected to the power system so that damage is kept to a minimum. Relays are also designed to provide secure and dependable operations so that the least amount of equipment is removed from the system when a fault occurs. The design of relays has changed and improved during the last several years.

2.1.1 Digital Relay Protection Enhancements

Modern advances of computer-based equipment, lower equipment design margins, economics, and increased demands to improve reliability have introduced new design requirements that were not considered in older relay schemes. These advances and demands led to the introduction of digital relays.

Digital relays were first introduced in the late 1970s and were designed to replicate the elements and characteristics of conventional electromechanical relays. As designs have improved, relays have become faster, more selective, and extremely accurate while at the same time providing feedback that have reduced outage times. Because the new modern multifunctional digital relays allow the relay engineer to have multiple protection elements in one device, the number of relays in a protection scheme has been reduced. This means that several relays are no longer required for the various protection schemes. Digital relays can be installed at a much lower cost and, therefore, the use of digital relays can result in a significant economic savings.



Key O&M Cost Point

Because modern multifunctional digital relays allow the relay engineer to have multiple protection elements in one device, the number of relays in a protection scheme has been reduced.

**Key O&M Cost Point**

Digital relays can be installed at a much lower cost and, therefore, the use of digital relays can result in a significant economic savings.

Even though the primary purpose for installing a protective relay has not changed, digital relaying technology has allowed design engineers to solve relaying problems with solutions that were not attainable with older relays. Scheme improvements can be implemented today by introducing new control and monitoring designs. Communication to the devices from remote locations has helped to improve safety and reliability resulting in more efficient operations.

2.2 General Overview of Digital Relays

The term digital relay is an imprecise term that has been used generically to describe any relay utilizing a microprocessor or microcomputer. There are actually two classifications of microprocessor relays—the analog hybrid relay and the numerical relay.

**Key Technical Point**

There are actually two classifications of microprocessor relays—the analog hybrid relay and the numerical relay.

Digital relays (also known as the analog hybrid) utilize analog signal measurement techniques (typical of solid-state relay systems) to provide the protective (trip) functions. The role of the microprocessor in this class of protective relay was limited to providing some timing, control, and ancillary logic functions. In the early development of microprocessor relays, this role was necessary to provide high-speed measurement and protection due to the limited processing ability and speed of the microprocessors and the analog-digital converter (ADC) systems available at the time.

As the speed and power of microprocessors and ADCs improved, fully numeric relays evolved. A numeric (or numerical) relay digitally samples the incoming analog signals, converts them to a binary number, and passes them to a microprocessor chip where algorithms perform mathematics to measure the condition of the power system and to provide the protective (trip) functions. Microprocessors also perform control and logic functions.



Key Technical Point

A numeric (or numerical) relay digitally samples the incoming analog signals, converts them to a binary number, and passes them to a microprocessor chip where algorithms perform mathematics to measure the condition of the power system and to provide the protective (trip) functions.

2.2.1 Numerical Relay Construction

Numerical relay hardware construction is made up of several subsections. Figure 2-1 describes the typical components that make up these subsections.

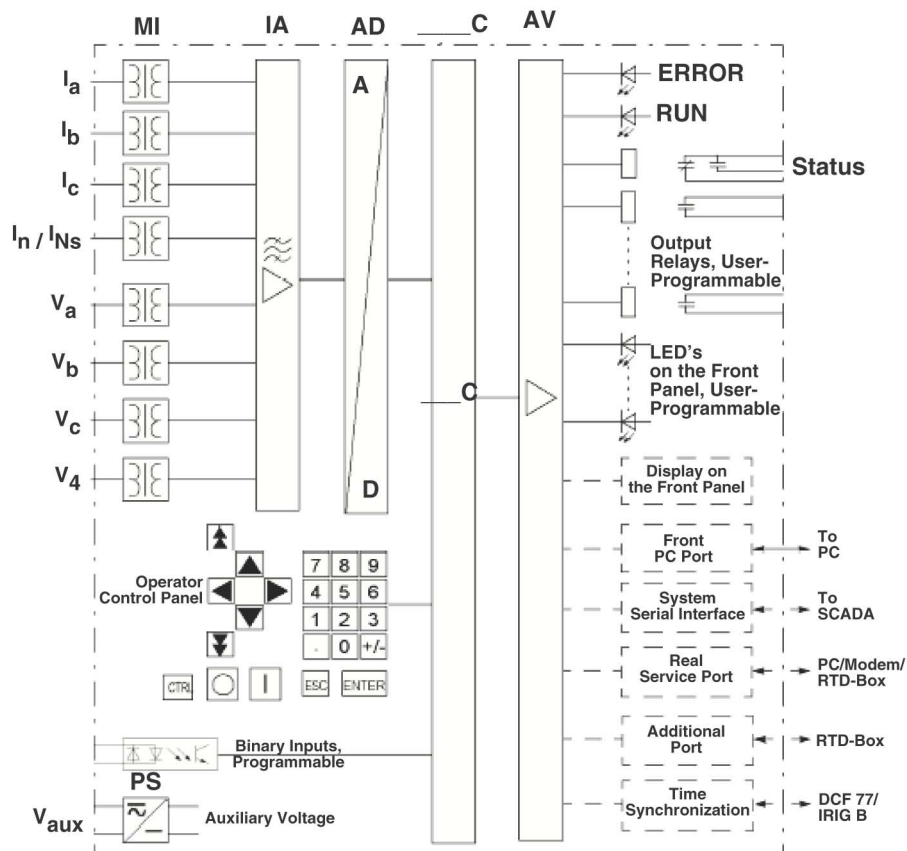


Figure 2-1
Typical Relay Hardware Structure Subsection Drawing

2.2.1.1 Power Supply

The Power Supply subsection provides the various voltages necessary to drive the electronic components of the relay. Because the power supply is a high-profile, single-point-of-failure, it was often used as the rationale to avoid the use of numeric relays, especially in critical applications. In reality, the microprocessor relay power supply has proven to be highly reliable.

Power supplies may be specified for many different voltage applications—both AC and DC. An obvious problem occurs when a user applies the wrong level of voltage to the relay power supply. A power supply rated for 48 VDC does not usually fare well when subjected to 120VAC, 125VDC, or 250VDC. Some relays offer universal power supplies that are capable of handling a large range of both AC and DC voltages. This reduces the potential for catastrophic failure due to human error and helps to reduce the necessary inventory of spare relays.



Key Technical Point

Power supplies may be specified for many different voltage applications—both AC and DC.



Key O&M Cost Point

Some relays offer universal power supplies that are capable of handling a large range of both AC and DC voltages. This reduces the potential for catastrophic failure due to human error and helps to reduce the necessary inventory of spare relays.

2.2.1.2 Measuring Inputs (MI)

In the measuring inputs subsection, currents and voltages from the incoming analog signals are converted to voltage at a level appropriate for internal processing. The number of inputs will vary depending on the type of relay for the application.

2.2.1.3 Input Amplifiers (IA)

In the analog input subsection, the low voltage outputs of the measuring inputs section are passed on to input amplifiers. In this stage, the voltage and current signals (are designed to optimize the bandwidth and processing speed of the relay) are filtered.

2.2.1.4 Analog-to-Digital (AD)

The analog-to-digital subsection consists of a multiplexer, an analog-to-digital converter, and memory components to transmit digital signals to the microcomputer subsection.

2.2.1.5 Microcomputer (μ C)

The microcomputer subsection processes the measured values and executes the actual protection and control functions. Functions include filtering, preparing measured quantities, continuous monitoring, control of signals for logic functions, output of control commands, recording of fault information, and management of the operating system.

2.2.1.6 Displays

The displays include the HMI for a visual display of information to the user, light emitting diodes (LEDs) for displaying target and status information on the front panel of the relay, and diagnostic lights to indicate when the relay diagnostics have detected an error in the processing.

When offered, programmable LEDs and programmable display text represent a great improvement over the capability of electromechanical relays. They allow for pickup indications during testing and improve the ability to perform postoperative analysis to determine the quality of relay system operations.

2.2.1.7 Communications

Digital relays are typically provided with a variety of communication options. These options may include multiple ports for communicating with the relay both locally and remotely, connection to a network or SCADA System, and connection through multiplexers or telephone lines.

Options may include RS232, RS485, Ethernet, and multi-mode or single-mode fiber connections. Some manufacturers also provide serial ports to connect other devices such as resistive thermal devices (RTDs) that convert thermal information into serial communication data for monitoring thermal points in equipment such as transformers, generators, or motors. Protocols consist of DNP3, Modbus, Profibus, International Electrotechnical Commission (IEC), and UCA.

2.2.1.8 Input/Output (I/O)

The input/output (I/O) subsections provide a means for the numeric relay to communicate with the “outside world.” Binary inputs are optically isolated inputs that allow information regarding the status of external devices to be used in the logical decisions of the relay. Breaker position auxiliary contacts, circuit breaker control (TRIP/CLOSE) switch position, generator stop valve position, pilot communication indications for pilot blocking and permissive schemes, and recloser ON/OFF switch position are a few of the potential applications for binary inputs. This type of information is critical to allow the programmable relay logic to make sound control decisions.

**Key Technical Point**

The input/output (I/O) subsections provide a means for the numeric relay to communicate with the ‘outside world.’

As the programmable logic capabilities of numeric relays advance (in some cases rivaling or surpassing the capability of stand-alone PLCs), more control devices are being eliminated. This benefit reduces project costs, scheme complexity, and the physical space required for installing a relay system. As the value of a powerful internal logic controller becomes evident, the demand for binary I/O increases.

**Key O&M Cost Point**

As the programmable logic capabilities of numeric relays advance (in some cases rivaling or surpassing the capability of stand-alone PLCs), more control devices are being eliminated.

Some relays may require that the nominal voltage of binary inputs be specified when ordering. Other relays are designed to accept a full range of nominal DC voltages.

Binary outputs provide the means for the numeric relay to control external devices such as the tripping and closing of circuit breakers. Binary inputs can be used together with trip output contacts to actually monitor the health of circuit breaker trip coils. An opened or shorted trip coil can be detected and an alarm initiated.

2.2.1.9 Enclosure Case

Digital relays are supplied in a variety of physical sizes. Relays can be provided in surface or flush mount design. Relays can be sized like older technology designs or like 19-in. rack-mount styles (or a combination of both).

Terminal blocks for wires are typically connected on the rear of the case and the individual terminals are usually sized for double-ring lugs.

A communication port for the local PC interface is typically on the front panel of the relay and any additional communication ports for SCADA, IRTG B, and RTD boxes and modems are usually connected to the rear of the relay. To interface with the outside world, digital relay manufacturers provide a variety of faceplates with displays, controls, and targeting data.

2.2.2 Human Machine Interface (HMI)

One significant advantage of using digital relays over solid-state and electromechanical relays is the front panel interface. This interface provides the end user with the benefits of gaining access to operational information and the ability to manually apply setting changes locally at the relay device. This front panel interface is commonly called the human machine interface (HMI). The HMI typically has touch-pad keys for entering or retrieving relay data and a serial connection port for connecting a portable computer to perform operations using a relay configuration software.



Key Human Performance Point

The HMI typically has touch-pad keys for entering or retrieving relay data and a serial connection port for connecting a portable computer to perform operations using relay configuration software.

Typically the HMI operator interface on the front of the device is menu-driven and is provided with a display to visually access information stored in the relay device, which can include the following information:

- Metering and measured values
- Annunciations (trip logs, event logs, or equipment statistics)
- Controls
- Settings
- Relay health status

Relay HMI displays come in a variety of types and sizes depending on the relay design. The preferred displays are liquid crystal with a backlit feature so that they can be read easily. Displays are provided in multiple line formats or in a mimic display format. Figure 2-2 provides examples of a four-line display and a mimic display.

Numerical Relay Description



Figure 2-2
Examples of Four-Line HMI Display and Mimic Display

Because numerical relays contain extensive protection and control processing in one device, menus can contain multiple branch selections. To gain access to specific information, the end user is required to enter several steps to gain access to information in the menu tree. To speed the access process for frequently used information or controls, relays can be provided with function keys (sometimes called hot keys) that will allow the operator to quickly gain access to a location in the menu or to perform control operations with fewer menu steps (see Figure 2-3). Some numerical relays now come with these function keys that are fully programmable to meet the end user's requirements. The following list provides examples of function key operations:

- Trip logs
- Primary metering
- Trip/close control
- Raise/lower control
- Sync on/off

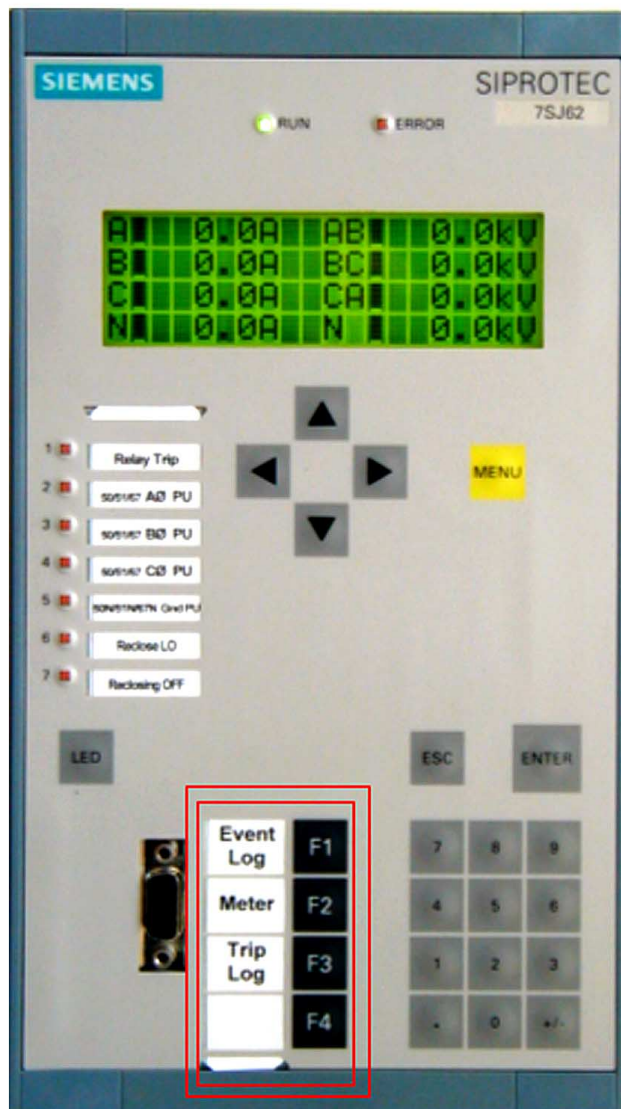


Figure 2-3
Example of Function Key Buttons

Touch-pad keys to access selections or to perform setting changes from the front display often include the following keys:

- Menu key
- Enter/Esc key
- Numeric keys
- Cursor keys

Numerical Relay Description

Digital relays store fault and sequence-of-event operation information within the device after a trip occurs. When a trip does occur, fault information must be accessible in a short period of time to minimize the outage time. Another beneficial feature of digital relays is that they provide usable fault information in an expeditious manner. Specific relay trip and fault information are provided on the HMI display using programmable LEDs and fault displays (see Figure 2-4). This information, which is immediately displayed after a trip occurs, helps the end user to determine where the fault occurred. The LEDs or display may also provide other nonfault information such as relay communication failure alarms, equipment position indications, synchronization conditions, and relay diagnostic alarms.

**Key Technical Point**

Digital relays store fault and sequence-of-events operation information within the device after a trip occurs.

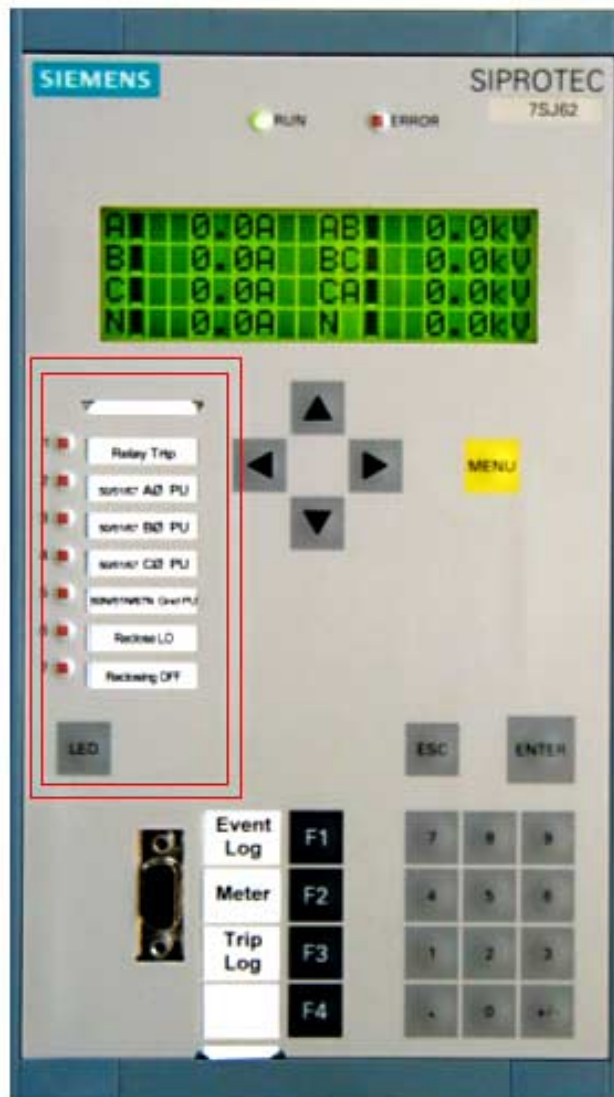


Figure 2-4
Example of LED and Fault Display

If a more detailed analysis is required after a trip operation, digital relays store detailed fault information that can be downloaded using the relay PC program. Stored information typically includes items such as the following:

- RMS and instantaneous waveform capture
- Vectors diagrams
- Harmonics
- R/X characteristics
- Relay protection element operation times

**Key Technical Point**

If a more detailed analysis is required after a trip operation, digital relays store detailed fault information that can be downloaded using the relay PC program.

2.2.3 Power System Protection Circuit Operation

The purpose of the power system is to generate, transmit, and distribute electric power to the consumer in a manner that is safe, reliable, and economical. Historically, protective relays have played a critical role in meeting this objective. Protective relays monitor the power system to detect undesired conditions that present a threat to system reliability and take action to remove the threat from the system with minimal adverse effects. In this way, protective relays limit damage to expensive electrical equipment and provide for the safety of personnel.

Technology advancements of the past several decades have vastly improved the protection and control capability of protective relays. Microprocessor relays have many advantages over their electromechanical predecessors. They provide innovative improvements in system protection, maintenance, and operation.

Several protective functions may be required for the reliable protection of electrical equipment. The extent and combination of the functions are dependent on a variety of factors such as equipment size and ratings, mode of operation, plant configuration, availability requirements, and design philosophy.

This document will attempt to address the functions required for typical protection scheme applications.

2.3 Relay Classifications

Prior to the advent of the numeric microprocessor relay, relays were generally discreet devices. In order to design a fully functional protection and control scheme, an engineer had to employ a mix of protective relays to meet the protection needs of the application. Because the protective relays were discreet devices, several means of categorizing protective relays were employed to aid in matching the relay to the application. Protective relays were classified by input (voltage, current, power, pressure, frequency, or temperature), by operating principle (percentage, multi-restraint, product, solid state, electromechanical, or thermal), or by performance characteristic (distance, directional-overcurrent, inverse-time, definite-time, ground, or phase).

Additional classes of relays existed that were a necessary component of most protection and control systems. Monitoring relays (such as fault detectors or alarm relays), programming relays (such as synchronizing and reclosing relays), regulating relays, and auxiliary control relays were often used to complete the protection system design.

Separating protective relays into categories simplified the task of choosing a complement of relays necessary to adequately protect an application and to plan for the necessary panel space and wiring to build the scheme.

For the most part, the need for all of this preliminary classification was eliminated by the modern multifunctional numeric microprocessor relay. An excellent example is a typical multifunctional generator/motor protection relay that has all of the functionality required to provide complete generator protection in a single box. Figure 2-5 shows the functions available in such a relay. Each line item in Figure 2-5 represents at least one electromechanical protective relay or, in some cases such as external temperature monitoring, a monitoring relay.

Key O&M Cost Point



The need for preliminary classification was eliminated by the modern multifunctional numeric microprocessor relay. An excellent example is a typical multifunctional generator/motor protection relay that has all of the functionality required to provide complete generator protection in a single box.

Numerical Relay Description

Protection functions

Protection functions	Abbreviation	ANSI No.	Generator Basic	Generator Standard	Generator Full	Motor Asynchronous	Transformer
Current differential protection	ΔI	87G/87T/87M	X	X	X	X	X
Stator earth-fault protection non-directional, directional	$V_0 >, 3I_0 >$ $\angle (V_0, 3I_0)$	59N, 64G 67G	X	X	X	X	X
Sensitive earth-fault protection (also rotor earth-fault protection)	$I_{EE} >$	50/51GN (64R)	X	X	X	X	X
Stator overload protection	$I^2 t$	49	X	X	X	X	X
Definite-time overcurrent-time protection with undervoltage seal-in	$I > + V <$	51	X	X	X	X	X
Definite-time overcurrent-time protection, directional	$I > >, \text{Direc.}$	50/51/67	X	X	X	X	X
Inverse-time overcurrent-time protection	$t = f(I) + V <$	51V	X	X	X	X	X
Overvoltage protection	$V >$	59	X	X	X	X	X
Undervoltage protection	$V <, t = f(V)$	27	X	X	X	X	X
Frequency protection	$f <, f >$	81	X	X	X	X	X
Reverse-power protection	$-P$	32R	X	X	X	X	X
Overexcitation protection (Volt/Hertz)	V/f	24	X	X	X	X	X
Fuse failure monitor	$V_2/V_1, I_2/I_1$	60FL	X	X	X	X	X
External trip coupling	Incoup.		4	4	4	4	4
Trip circuit supervision	T.C.S.	74TC	X	X	X	X	X
Forward-power protection	$P >, P <$	32F	X	X	X	X	X
Underexcitation protection (loss-of-field protection)	$1/x_d$	40	X	X	X		
Negative-sequence protection	$I_2 >, t = f(I_2)$	46	X	X	X	X	
Breaker failure protection	$I_{\min} >$	50BF	X	X	X	X	X
Motor starting time supervision	$I_{\text{start}}^2 t$	48	X	X	X	X	
Restart inhibit for motors	$I^2 t$	66, 49 Rotor				X	
Rotor earth-fault protection (f_n , R-measuring)	$R <$	64R (f_n)	X	X	X		
Inadvertent energization protection	$I >, V <$	50/27		X	X		
100 % stator earth-fault protection with 3 rd harmonics	$V_{0(3\text{rd harm.})}$	59TN, 27TN 3 rd h		X	X		
Impedance protection with ($I > + V <$) pickup	$Z <$	21		X	X		
DC voltage / DC current time protection	$V_{dc} >$ $I_{dc} >$	59N (DC) 51N (DC)			X		
Overcurrent protection during startup (for gas turbines) ²⁾	$I >$	51			X		
Earth-current differential protection ²⁾	ΔI_e	87GN/TN			X		
Out-of-step protection	$\Delta Z / \Delta t$	78			X		
Rotor earth-fault protection (1 to 3 Hz square wave voltage) ²⁾	$R_{\text{REF}} <$	64R (1 – 3 Hz)	X ¹⁾	X ¹⁾	X ¹⁾		
100 % stator earth-fault protection with 20 Hz voltage ²⁾	$R_{\text{SEF}} <$	64G (100 %)	X ¹⁾	X ¹⁾	X ¹⁾		
Rate-of-frequency-change protection ²⁾	$df/dt >$	81R	X ¹⁾	X ¹⁾	X ¹⁾		
Vector jump supervision (voltage) ²⁾	$\Delta >$		X ¹⁾	X ¹⁾	X ¹⁾		
Supervision of phase rotation	A, B, C	47	X	X	X	X	X
Undercurrent via CFC	$I <$	37	X	X	X	X	X
External temperature monitoring via serial interface ²⁾	(RTD)	38	X	X	X	X	X

Table 11/3 Scope of functions of the 7UM62

1) Optional for all function groups.

2) Available as of version V4.1 and higher.

Figure 2-5

Multifunctional Generator Relay Elements

In addition to having a multifunctional nature, modern numeric relays are also quite flexible and versatile. A relay with the multifunctional elements shown in Figure 2-5 can also be used to protect a large induction motor. This requires no special changes other than the click of a mouse in the configuration software.

With the high-powered programmable logic capability of numeric relays, multifunctional relays can replace many types of relays including monitoring, reclosing, and auto-synchronizing relays. There is even an application where a generator upgraded from electromechanical relays to numeric microprocessor relays was able to replace the synchroscope due to the power of the internal logic controller. While auxiliary relays cannot be totally eliminated, innovative design engineers can replace everything from lockouts to pistol grip switches with single multifunctional relays. The only limiting factor is the I/O capacity of the relays.



Key O&M Cost Point

With the high-powered programmable logic capability of numeric relays, multifunctional relays can replace many types of relays including monitoring, reclosing, and auto-synchronizing relays.

The multifunctional relay has the potential to replace many protective relays, auxiliary relays, control switches, and control wiring. Savings are realized in labor, panel space, inventory costs, installation time, and maintenance costs. These are issues that should be studied when considering the application of multifunctional relays.

2.4 Relay Terminology

Terms relating to protective relaying are extensive. ANSI/IEEE C37.100-1981, *Definitions for Power Switchgear*, provides definitions of conventional relay terms. These terms are also included in ANSI/IEEE Standard 100-1988, *IEEE Standard Dictionary of Electrical and Electronics Terms*.

Numerical Relay Description

The following new terms are associated with numerical relays and the latest protection schemes. While this is not a complete list, it covers the more frequently used terms with this class of relaying. New terminology continues to be developed as numerical relay designs are implemented and new schemes are introduced.

adaptive relaying:	Automatic changing of relay settings due to a change of state in the power system.
binary I/O:	Inputs and outputs of a microprocessor relay that are typically optically isolated to perform protection, control, and monitoring functions associated with the relay or relay scheme. This term is interchangeable with digital I/O.
digital I/O:	See binary I/O.
digital relay:	A relay that takes analog quantities, converts measured values into digital signals, and makes a decision based on these measurements.
flash:	A term used to describe a firmware upgrade using software to download a new update.
firmware:	EEProm program memory configured within the relay function keys allowing quick action or hot keys to perform a frequent operation without going through a menu or multiselection process.
HMI:	Human machine interface—the front panel display of a numerical relay.
IRIG B:	A time code format (Inter-Range Instrumentation Group - Type B) that consists of a 1000Hz carrier modulated with time code date BCD format that is used as a master time signal base for synchronizing times of multiple devices.
masking:	The assignment of points associated with a particular input, output, LED, display message, or event trigger within a relay.
master device:	A controlling device that can give or receive commands from an associated control center network control system.
microprocessor relay:	A relay that utilizes a microchip technology to perform measurements and to make protection and control decisions. The term is interchangeable with digital relay, numerical relay, and multifunctional relay.
multifunctional relay:	A digital or microprocessor relay that is provided with several protection elements and control functions.

numerical relay:	The term is interchangeable with digital relay, microprocessor relay, and multifunctional relay.
parameter:	A set point or setting within a relay.
protocol:	A communication language format used to connect the relay to external supervisory and control systems, personal computers, or other master devices (that is, Modbus RTU, DNP 3.0, or Profibus DP/FMS).
reverse interlock:	A protection scheme used where a downstream relay communicates with upstream device through communication networking to interlock the relays.
serial cable:	A data cable used to connect to the relay serial port for communication with a personal computer.
setting group:	A set of information containing all of the protection and configuration settings necessary for the operation of a numeric relay. Multiple setting groups for various operational contingencies may be stored in the memory of the numeric relay and activated as external system conditions warrant. Only one setting group may be active in a numeric relay. The number of user-defined setting groups varies by manufacturer.
slave device:	A device that receives commands from a master device associated with a control center network control system.
software:	A relay-programming program or firmware update program used on a personal computer.

2.5 Device Function Numbers

2.5.1 General Description

The protection elements that are provided in a multifunctional relay are classified by relay function numbers. These functions are defined in IEEE Standard IEEE Standard C37.2-1996 (R2001). This standard gives the definition and application of function numbers that are typically applied to power stations and substation facilities utilizing power and electrical equipment apparatus. Standard function numbers are referred to frequently throughout this document and are in defined in Appendix D.

2.5.2 Prefix/Suffixes

In addition to the relay device number, additional letters and numbers can be used in prefix and suffix form to identify a more specific use of the function. A prefix or suffix included with the number can also be used to define features, characteristics, or conditions of a device or piece of equipment. When a numerical relay associated with a specific circuit or with primary equipment (such as a feeder, motor, transformer, and generator), the suffixes F, M, T, and G are often used. In order to prevent confusion, each letter suffix should have only one meaning in individual pieces of equipment. To accomplish this, short abbreviations such as those contained in ASME Y1.1-1989 are recommended. More detail on prefixes and suffixes are described in IEEE Standard C37.2-1996 (R2001).

3

NUMERICAL RELAY CONSTRUCTION AND OPERATING PRINCIPLES

3.1 Electrical Subassemblies

3.1.1 Power Supply

Most typical microprocessor relays can be supplied by AC or DC supply voltage and should be ordered accordingly. Momentary dips of the supply voltage up to 50 ms are bridged by a capacitor. Voltage dips can occur, for example, if the voltage supply system (substation battery) becomes short-circuited or experiences a severe variation in load. Settings, annunciations, and waveform captures are saved even if supply voltage is lost to the relay. Internal batteries that are used commonly have a life span of 10 years. It is advisable to change these batteries prior to their end of life. The instruction manuals for the most typical microprocessor relays illustrate the mounting position of the batteries.



Key Technical Point

Settings, annunciations, and waveform captures are saved even if supply voltage is lost to the relay. Internal batteries that are used commonly have a life span of 10 years. It is advisable to change these batteries prior to their end of life.

3.1.2 Motherboard

The motherboard for the typical microprocessor relays is where the relay's microcomputer resides. In addition, the power supply fuse and batteries are also located on the motherboard. The actual protection and control functions of the relays are processed in the microcomputer system (μ C). Specifically, the μ C performs the following functions:

- Filters and prepares the measured quantities
- Permanently supervises the measured quantities
- Monitors the pickup conditions for the individual protection functions
- Evaluates limit values and sequences in time
- Controls signals for the logic functions

- Makes decisions regarding trip commands
- Signals protective behavior via LED, LCD, relay, or serial interface
- Records messages and data for events, alarms, faults, and control actions and provision of the data for analysis
- Manages the operating system and the associated functions such as data recording, real-time clock, communications, and interfaces

3.1.3 I/O Modules

Typical microprocessor relays contain a various number of binary inputs and outputs. Binary inputs are rated at the same voltage as the relay supply voltage. The pickup threshold for binary inputs is usually around 70% of the rated voltage. For example, the pickup of the inputs would be approximately 88VDC on a 125VDC relay. This value may be settable using relay management and communications software. The inputs consist of transistors that monitor voltage at the terminals and transmit signals to the microcomputer for processing. The μ C obtains external information through the binary inputs such as blocking commands for protective functions or the position indications of circuit breakers. The μ C issues commands to external equipment via the output contacts. Binary outputs are relays that will close or open when a command is issued by the microcomputer. These output commands are generally used to operate circuit breakers or other switching devices. They can also be connected to other protective devices, annunciators, or external carrier equipment for use in pilot-relaying schemes.

3.1.4 Communication Modules

With respect to communication, particular emphasis has been placed on high levels of flexibility, data integrity, and the utilization of standards common in energy automation. The design of the communication modules provides the benefits of interchangeability in equipment, the potential for acceptance of future standards, and an increase in industry-wide knowledge of communication protocols.



Key Human Performance Point

With respect to communication, particular emphasis has been placed on high levels of flexibility, data integrity, and the utilization of standards common in energy automation. The design of the communication modules provides the benefits of interchangeability in equipment, the potential for acceptance of future standards, and an increase in industry-wide knowledge of communication protocols.

The following interfaces are often available as communication paths utilized by the relay:

- **PC interface:** The PC interface, typically accessible from the front of the unit, permits quick access to all parameters and fault event data. Of particular advantage is the use of relay management and communications software during commissioning.
- **Service interface:** Several protection relays can be centrally operated with relay management and communications software (that is, via a star coupler or RS485 bus). Upon connection of a modem, remote viewing of relay measurements, historical event information, and settings is possible. With additional password clearance, control actions such as setting changes and breaker control may be enabled. (Alternatively, the external temperature monitoring box can be connected to this interface.)
- **Time synchronization interface:** A synchronization signal (DCF 77, IRIG B via satellite receiver) may be connected to this input if no time synchronization is executed on the system interface. This offers a high-precision time tag.
- **System interface:** This interface is used to carry out communication with a control system. The system interface supports a variety of communication protocols and interface designs depending on the module connected.

The following hardware protocols are available for typical microprocessor relays:

- **Fiber-optic double-ring circuit:** The fiber-optic double-ring circuit is immune to electromagnetic interference. Upon failure of a section between two units, the communication system continues to operate without interruption. If a unit fails, communication with the rest of the system is not affected.
- **Ethernet or RS485 bus:** With this data transmission via copper conductors, electromagnetic interference is largely eliminated by the use of twisted-pair conductors. Upon failure of a unit, the remaining system continues to operate without any faults.
- **Star structure:** The relays are connected with a fiber-optic cable with a star structure to the control unit. The failure of one relay/connection does not affect the others.

3.2 Numerical Relay Construction

Figure 3-1 shows the various components that make up the physical construction of a typical microprocessor relay.

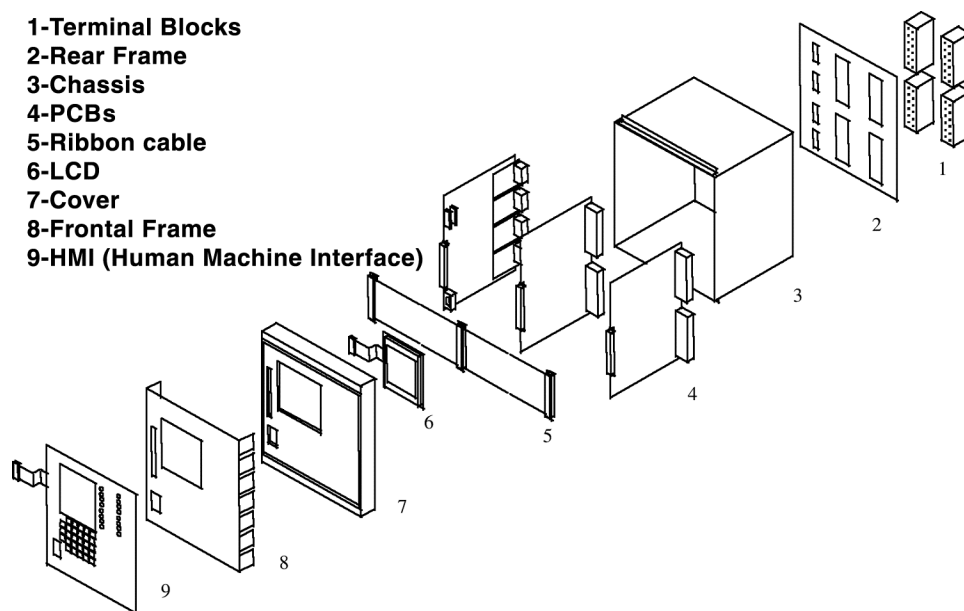


Figure 3-1
Construction of a Typical Microprocessor Relay

3.2.1 Case

In order to get a printed circuit board (PCB) on which the circuits function properly, the trace routing, the placement of components such as transformers, transducer inputs and outputs, binary inputs and outputs, connectors, and the decoupling used with certain integrated circuits (ICs) are optimized and used to define the minimum case size. The placement of components includes the arrangement of transformers, transducer inputs and outputs, binary inputs and outputs, and connectors.

In conjunction with the distance pieces on the PCB and the shaping of the connector modules, the guide plate cams ensure proper mounting and fixing of the module.

According to the protection function or the control scheme where the relay is applied, different case sizes can be required due to the hardware configuration. Figure 3-2 provides examples of various microprocessor relay case sizes.



Figure 3-2
Example of Various Microprocessor Relay Case Sizes

All wires (cables) are connected at the rear side of the relay as shown in Figure 3-3 except when microprocessor relays are surfaced-mounted,



Figure 3-3
Example of Surface-Mounted Microprocessor Relay Configuration

Special relay versions with a detached cable-connected operator panel may also be available from various manufacturers (see Figure 3-4). This allows the installation of the relay itself in the low-voltage compartment and the installation of the operator panel separately in the door of the switchgear.



Key O&M Cost Point

A relay with a detached cable-connected operator panel allows the installation of the relay itself in the low-voltage compartment and the installation of the operator panel separately in the door of the switchgear.



Figure 3-4
Microprocessor Relay With Detached Operator Panel

3.2.2 Chassis

The chassis in a numerical relay is specially designed for protection from mechanical stress and electromagnetic fields.



Key Technical Point

The chassis in a numerical relay is specially designed for protection from mechanical stress and electromagnetic fields.

The PCBs provide connections for electronic components such as passive devices, transistors, microprocessors, and ICs.

The inner part of the housing is free from enamel and thus functions as a large contact plane and shield with solid electrical conductivity. The inner housing also mates with the grounding (earthing) blades of the module. Connection to earth is made before the plugs make contact. A grounding (earthing) area is provided at the housing to which a grounding strip can be connected in order to ensure solid low-impedance grounding.

As with any other electronic devices, the numerical relay must comply with standards relating to electromagnetic compatibility and concerning electrical equipment for use within certain voltage limits.

3.2.3 Printed Circuit Cards

As numerical relay hardware requirements have become more complex (requiring more components), the PCB has become more populated and dense with wiring and components.

The substrate of the board itself is an insulating and nonflexible material. The thin wires that are visible on the surface of the board are part of a copper foil that initially covered the whole board. In the manufacturing process, this copper foil is partly etched away. The remaining copper forms a network of thin wires. These wires are referred to as the conductor pattern. They provide the electrical connections between the components mounted (such as binary inputs, binary outputs, or serial interfaces) on the PCB. Figure 3-5 shows a typical microprocessor relay-printed circuit card.

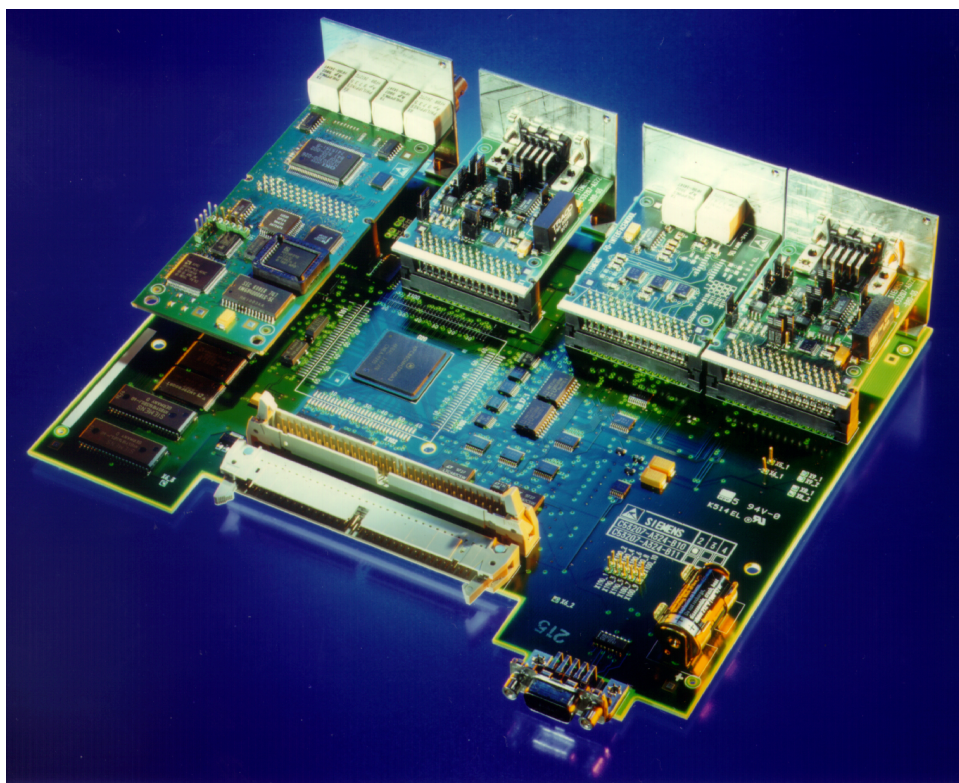


Figure 3-5
Typical Microprocessor Relay-Printed Circuit Card

3.2.4 Cover

The protective cover features a flexible design that allows users to easily disconnect and withdraw it from the case for access to the PCBs without disturbing the wiring.

Formerly, the front covers of relays were transparent and removable. They had provisions for wire and lead seals to prevent tampering by unauthorized personnel. Presently, manufacturers provide free access to the control keys and frontal display; however, changing the settings and controlling the breakers and switches are password-protected tasks.



Key Human Performance Point

Manufacturers provide free access to the control keys and frontal display; however, changing the settings and controlling the breakers and switches are password-protected tasks.

When the relay is disconnected, the current transformer (CT) connections in the case are automatically shorted to protect the CT from overvoltages and damage.

3.2.5 LED Targets/Indication

Freely assignable or defined by the manufacturer, LEDs are used to visually display process or device information. On some relay models, one LED is dedicated to display the functional status of the device (watchdog) and another one for the power supply status. The LEDs can be labeled according to user requirements. Typically, an LED or target reset key resets the LEDs configured as latched and can be used for LED testing.

The following list provides a few examples of LED applications:

- Individual phase pickup indication with latched or unlatched LEDs
- Trip indication
- Status indication of the breakers or switches
- Protection block indication

3.2.6 Front Display

The form and function of numeric relay front panel displays will vary by manufacturer. Some features are common to all, but each manufacturer generally has some unique features. The key function is the ability to retrieve data and to apply settings and configuration information. Generally, every function that can be performed via the front display can also be performed using a locally connected personal computer (although the reverse is not true).

With devices having integrated or detached operator panels, information such as event messages, measured values, and the functional status of the device are provided via LEDs and a display screen (LCD) on the front panel. Integrated control and numeric keys facilitate interaction with the remote device in conjunction with the LCD. All of the information of the device such as configuration and setting parameters, operating and fault messages, and measured values can be accessed via these elements. Setting parameters may be changed in the same way.

**Key Human Performance Point**

Information such as event messages, measured values, and the functional status of the device are provided via LEDs and a display screen (LCD) on the front panel.

On some models of numeric relays, process and relay information can be displayed on the large illuminated LC display graphically in the form of a mimic diagram or as text in various lists. The control of circuit breakers and other equipment may be possible from the front panel of the device. The status of the primary equipment can be transmitted to the device via auxiliary contacts connected to binary inputs.

A serial PC interface is provided for local communications with the device through a personal computer using the supplier-operating program. This facilitates a comfortable handling of all device functions.

3.3 Design Requirements

Relay standards provide the criteria and guidelines for design engineers to develop protection products that perform reliably in a variety of locations. Because protective relays may be required to operate in harsh environments, they are tested to meet a variety of standards related to mechanical, electrical, thermal, and seismic conditions. Specific standards may be viewed to be a higher requirement versus another standard depending on the environment, application, and customer philosophy of appropriate relay design. The following sections list some of the more important design considerations.

**Key Human Performance Point**

Because protective relays may be required to operate in harsh environments, they are tested to meet a variety of standards related to mechanical, electrical, thermal, and seismic conditions.

3.3.1 Service Conditions

Service conditions that can affect relay operation can include the following:

- **Ambient Temperature** - Relays are typically designed to operate in industrial environments with ambient temperatures in the range from -20°C (4°F) to +55°C (131°F). The ambient temperature is the temperature of the air measured 30 cm (11.8 in.) from the outside surface of the enclosures or covers of the relay equipment.
- **Altitude** - The usual condition of altitude is typically less than 1500 m (5000 ft).
- **Humidity** - The average relative humidity may be up to 55% outside of enclosures or covers for temperatures up to 40°C (104°F) with excursions up to 95% for a maximum of 96 hours without internal condensation.

Other environmental or service conditions can affect proper relay operation if the relays are exposed to excessive conditions. These conditions can include the following:

- Fumes or vapors
- Dust
- Explosive mixtures of dust or gases
- Steam
- Salt air
- Transportation or storage conditions
- Extreme or sudden temperature changes
- Extreme supply voltage fluctuations
- Excessive electrical wave distortion
- Excessive electrical noise
- Electromagnetic radiation
- Nuclear radiation

3.3.2 Ratings

Modern numerical relays are tested using the latest industry ANSI/IEEE and IEC standards to prove that they meet industry rating requirements. Many of the standards were initiated in the era of the electromechanical relay and have developed and been revised over time as relay technology has changed.



Key Technical Point

Modern numerical relays are tested using the latest industry ANSI/IEEE and IEC standards to prove that they meet industry rating requirements.

3.3.2.1 Voltage/Current

Numerical relays contain sensitive electrical components that are designed to operate at specific values of voltage and current. Voltages range from 110 VAC–480 VAC and 24 VDC–250 VDC. Currents are provided in either 1A or 5A (AC) rating. The maximum design rated voltage is the highest rms alternating voltage or direct voltage. The maximum current is the highest rms alternating current or direct current. These maximum values are the limits at which the relay can operate continuously.

The operating coils of older electromechanical and solid-state relays typically determined the relay's rating. Today, numerical relays are supplied with multiple range or universal power supplies and binary inputs/outputs that operate at specific voltages that are set by using internal links or jumpers in the relay. The current and voltage sources can also have multiple operating ratings. Relays can be provided with secondary current selections of 1 A or 5 A. Secondary voltages to the relay can be configured for a range of voltages and can typically be connected wye or delta by a setting parameter rather than a hardware configuration. Voltage inputs can be configured for phase-phase or phase-ground.

3.3.2.2 Burden/Overload

Relay burden is greatly reduced with the use of numerical relays. The power consumption of numerical relays can be expected in the 0.04–0.10 VA range. This means that in many applications, the relay burden is negligible. In older applications where the relay burden was much higher, intermediate current transformers may have been required. Numerical relays normally no longer require these intermediate transformers.

**Key O&M Cost Point**

The power consumption of numerical relays can be expected in the 0.04–0.10 VA range. This means that in many applications, the relay burden is negligible.

Thermal overload capacities are also higher. For example, the effective thermal overload can reach a rating of 500 A (1 sec) and a dynamic rating of 1250 A (half cycle).

3.3.3 Design Testing

Design testing is performed to validate that a particular relay's design, construction, and materials perform as expected and are adequate for use in the intended application. Tests are performed during the relay production and are tested using ANSI/IEEE and IEC guidelines and standards.

**Key Technical Point**

Design testing is performed to validate that a particular relay's design, construction, and materials perform as expected and are adequate for use in the intended application.

3.3.3.1 Dielectric Testing

Dielectric testing is performed to ensure adequate insulation resistance between circuits, between circuits and ground (relay frame), and across open contacts. Relays must withstand a low frequency test voltage of 2500 volts rms. Full-strength dielectric testing is not recommended when a relay is in service. On numerical relays, this test is not required for power supply and RS495/RS232 communication ports.

3.3.3.2 Surge Withstand Capability

Surge withstand requirements increased when solid-state relays were introduced because the need for standardized surge testing became evident due to concerns about their ability to withstand credible surges. In response, standardized surge tests were developed to ensure adequate surge withstand capability (SWC) of protective relay systems. SWC testing is a design test and is not usually performed on all production units or by users. SWC testing includes two tests—an oscillatory waveform test and a fast transient test. The oscillatory waveform is a high-frequency, decaying waveform between 2.5 kV and 3.5 kV. The oscillatory test waveform is representative of surges measured on actual systems. The fast transient waveform is a unidirectional wave with an extremely rapid rise time to a crest voltage between 4 kV and 5 kV. The fast transient test simulates surges caused by interruption of inductive devices. Thus, older

relay designs most likely were not subjected to this type of surge testing. These tests are not performed on communication ports and time synchronization inputs.

3.3.3.3 Radiated Electromagnetic Interference

The electromagnetic fields produced by portable communications devices can affect the proper operation of semiconductor devices. For this reason, numerical relays are tested to ascertain their susceptibility to electromagnetic fields in the radio frequency domain. High-frequency tests are required and use a 2500 peak value at 1 MHz and electrostatic discharge of 8 kV contact discharge and 15 kV air gap discharge. Unmodulated and modulated radio frequency field tests are performed in the range of 27–500 MHz (unmodulated) and 80–1000 MHz (modulated) at 10 V/meter. Transient bursts are tested at 4 kV (5 kHz) and pulse modulated tests at 900 MHz with a repetition rate of 200 Hz.

3.3.3.4 Qualification for Class 1E Applications

Rigorous qualification testing is performed on protective relays designed for use in nuclear plant Class 1E systems. Qualification testing demonstrates the design adequacy of equipment under normal conditions, abnormal conditions, during a design basis event, and subsequent to a design basis event.

A protective relay test program consists of aging, performance, software, and seismic evaluations. Significant aging mechanisms evaluated include time and temperature effects, operating cycles, and radiation. Other aging mechanisms are not considered significant for expected applications.

3.3.3.5 Seismic Testing

Seismic testing of protective relays is required for Class 1E applications at nuclear plants. However, in locations particularly susceptible to earthquakes, seismic testing is often specified for critical protective relay applications as an additional precaution regardless of Class 1E requirements. Numerical relays are much less susceptible to vibration when compared to older electromechanical and solid-state relays.

4

TYPES OF RELAY PROTECTION – APPLICATION AND OPERATION

4.1 Distance Protection (21)

4.1.1 Applications

The distance protection function on generators (function 21 – see Appendix D) is used as a fast backup protection for the generator, extending up to approximately 70% into the unit transformer. In addition, the distance protection function can be applied as a backup protection for faults on the transmission system. The reach and the delay in this case have to be coordinated with the primary and secondary protection on the transmission system. MHO and quadrilateral characteristics are commonly used for this application.



Key Technical Point

The distance protection function on generators is used as a fast backup protection for the generator, extending up to approximately 70% into the unit transformer.

Distance protection is applied to generators by measuring currents on the neutral side of the generator and voltages at the generator terminals. Because of the location of the current and potential transformers, generator faults can be detected by the impedance protection with the generator connected to the power system or isolated from the power system. Because all faults flow forward, a reverse-looking zone is not required for generator protection.

If the excitation system is fed from the generator terminals or from the transmission network, the excitation voltage can rapidly decay to almost zero during a fault. This results in a decreasing short-circuit current and in a possible reset of the distance element during the fault. Therefore, the distance pickup as well as the trip is normally maintained and supervised by an undervoltage element.

If the pickup element of the distance function is supervised by an overcurrent element, a pick up on the overload current must be prevented in any case.

4.1.2 Principles of Operation

4.1.2.1 Zone 1 Setting

The Zone 1 is calculated such that it reaches up to 70–80% into the unit transformer. If the generator is connected to the transmission network via a delta-wye unit transformer, only the phase distance elements are used. In this configuration, the generator system is normally not grounded preventing the distance element from picking up for ground faults. The load over the auxiliary transformer must be considered because the relay can overreach. If a quadrilateral characteristic is used, the R-reach can be set equal to the X-reach because high-resistive arc faults are unlikely. The delay time for the Z1 is set with a delay of 5–6 cycles to give the differential protection the priority to clear the fault first.

4.1.2.2 Use of Overreaching Zone

When the generator is temporarily removed from the transmission network, the overreaching zone is no longer concerned with an overtrip for generator faults. With the generator off-line, the reach of the impedance zone can be increased to 120% of the transformer impedance. This provides 100% protection of the step-up transformer. An alternate setting group configured to provide this increased sensitivity can be automatically applied when the relay determines that the generator has been switched off-line. Automatic initiation of the setting group change may be controlled via the “a” (or “b”) contact of the breaker.

4.1.2.3 Zone 2 Setting (or Zone 3 If Zone 2 Is the Overreaching Zone)

Zone 2 is used as backup protection for bus faults and line faults on adjacent lines to insure that the generator will not continue to supply fault current over a long time period if the primary protection fails to clear the fault (that is, relay failure or breaker failure). Zone 2 reach should cover the longest of the adjacent lines and coordinate with the primary transmission network protection. In-feed from other generation sources on the transmission bus, as well as the vector group of the step-up transformer, must be considered when setting the Zone 2 reach. Load blinders are necessary in some cases to avoid tripping under high load conditions.

The distance element should not operate on power swing impedances. Therefore, a power swing blocking function is required to prevent a trip for this situation. It is desirable to take the generator off-line in an out-of-step event, but this has to be managed by a separate out-of-step function.

4.2 Synchronizing (25)

4.2.1 Application

Improper synchronizing of a generator to the power system grid can damage the generator and/or the prime mover. To avoid damaging the generator unit when placing it on-line, highly secure synchronizing and/or automatic synchronizing relays are used to ensure that the frequency,

voltage magnitude, and phase angle are properly matched before connecting the generator to the system. Modern digital relays will also check the phase rotation of the generator and the systems to be connected. The relay will jog the machine voltage and speed to within preset limits. Synchronizing relays automatically perform this function and initiate a signal to close the breaker at the right instant in time. The relay will consider all of the delay times associated with breaker closing (from the breaker to the relay operating times) to deliver the closing command prior to the actual instant of synchronism. The closing command must be based on the speed at which the two systems are moving and the previously mentioned delay times. This ensures that the machine is connected to the system with no phase angle difference.



Key Human Performance Point

To avoid damaging the generator unit when placing it on-line, highly secure synchronizing and/or automatic synchronizing relays are used to ensure that the frequency, voltage magnitude, and phase angle are properly matched before connecting the generator to the system.

Synchronizing relays or high-speed synchronizing-check relays can be configured to supervise the activity of bringing a generator on-line manually. In this capacity, the relay allows only the generator's circuit breaker to close when frequency and phase angle are within prescribed limits. Slow-speed induction-type synchronizing-check relays are not recommended for large generators because their accuracy is not compatible with the small angular window for these machines. Digital relays can perform this function.

Synchronism check relays are used to connect two or more synchronous power sources to a common bus (for example, energizing a main transmission switchyard bus from two main feeders).

4.2.2 Principles of Operation

The principles of operation of the synchronizing (25A) and synchronizing-check (25) relays are almost identical. Both relays are connected to two system voltages through voltage transformers. Digital relays simplify the system connection because they perform the mathematical matching of voltages digitally as opposed to using interposing matching transformers. The latest digital relays can be applied across unit transformers or they can be applied to voltage transformers with different output voltages. Before digital relays were developed, a phase-to-phase connection was normally used. Digital relays provide added security if three-phase connections are made to the relay. The relay can then calculate the direction of rotation of the two systems. The older generation of synchronizing relays would permit the connection of two systems if the rotational direction was not the same.

The digital synchronizing relay will take the two system voltages and calculate the voltage, phase angle, and frequency difference between the applied voltages. Digital relays use various methods to calculate these quantities accurately.

A synchronizing-check relay will calculate the difference in voltage (ΔV), phase angle ($\Delta\theta$), and frequency (Δf). The relay will issue a close command each time that these parameters are met. The relay close contact is normally wired in series with a contact from a circuit breaker control switch. The operator of the control switch is responsible for ensuring that the breaker is closed with the smallest phase angle difference between the two systems. The operator normally relies on a sync-scope to estimate the correct instance of closure. The relay can also be set to identify if the system conditions are live or dead. A digital relay can be set to connect the systems if any combinations of live-dead conditions are permitted between the systems to be connected.

The automatic synchronizing relay will issue a close command only when all synchronizing parameters are met for voltage difference (ΔV), phase angle difference ($\Delta\theta$), or frequency difference (Δf). The relay will issue a close command based on the live-dead conditions and the point at which the systems will reach little or no angular difference. The relay will issue the close command prior to this point, taking into account the speed at which the systems are moving relative to each other and the operating time of the circuit breaker. The synchronizing relay must be supervised by a synchronizing-check relay to provide a two-out-of-two condition for system connection. Added security is provided by dual channel synchronizing relays where the relay is broken into two separate relays performing the same synchronizing functionality using different calculation methods. This type of relay is highly recommended on large machines to provide the security and repeatability required.

The automatic synchronizing relay provides jogging signals to the excitation control system (to raise or lower the machine voltage) and to the machine governor control (to increase or decrease the machine speed). The relay automatically jogs the machine into position for secure and repeatable closure free of any human error.



Key O&M Cost Point

The automatic synchronizing relay provides jogging signals to the excitation control system (to raise or lower the machine voltage) and to the machine governor control (to increase or decrease the machine speed). The relay automatically jogs the machine into position for secure and repeatable closure free of any human error.

Figure 4-1 depicts the basic application structure of modern synchronizing or synchronizing-check relays.

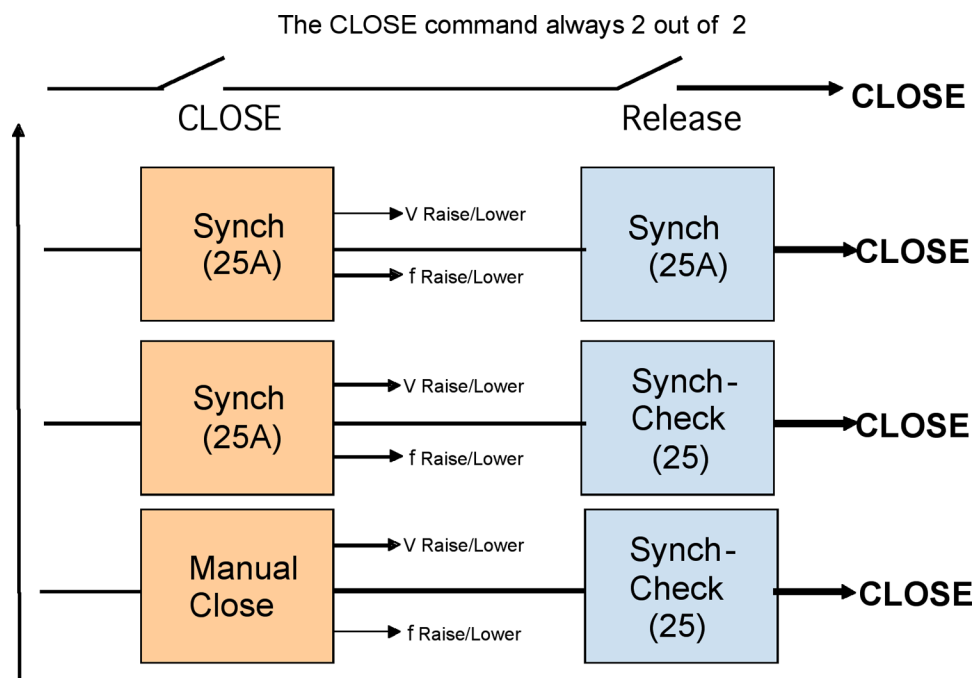


Figure 4-1
Basic Structure – Synchronizing or Synchronizing-check Relay

4.3 Undervoltage Protection (27)

4.3.1 Applications

The undervoltage protection function detects voltage collapses on transmission lines and electrical machines. If not detected and removed from the system, persistent undervoltage conditions can cause operating problems, damage to customer equipment, and a possible loss of stability.

4.3.1.1 Motor and Bus Undervoltage Protection

Undervoltage relays protect induction motors and large synchronous motors against low voltages. On startup, low voltages can prevent a motor from attaining rated speed. Undervoltage conditions can also cause a running motor to lose speed and draw excessive magnitudes of current. Motors should be tripped if subjected to severe undervoltage conditions for more than a few seconds. Undervoltage trips for motors generally include some time delay. Momentary undervoltage conditions are not damaging to motors and do not require protective action. However, an excessive transient undervoltage condition or loss of power can cause a motor to stall, potentially damaging the motor.

Time-undervoltage relays are set to dropout when voltage falls below the expected minimum transient voltage for the bus (usually 75–80%). The ability of a motor to reaccelerate under load is also a consideration in determining the dropout set point. The relays will trip the motor after a

short time delay. A motor overload resulting from an undervoltage condition will eventually cause the motor's time-overcurrent relays to actuate; however, an undervoltage relay can detect and respond to the undesirable condition much sooner, thereby minimizing the possibility of motor damage.

A second function performed by undervoltage relays is to disconnect motors from a deenergized bus to prevent them from automatically restarting when power returns to the bus. The cumulative in-rush caused by several motors attempting to start at once may overburden the bus, possibly causing the bus to trip again on overcurrent or undervoltage.

In addition to transient and loss of power undervoltage protection, nuclear plants must also protect against a sustained undervoltage condition (degraded grid voltage) that is above the transient undervoltage relay set points. A degraded grid voltage at nuclear plants is of concern for the following two reasons:

- An undervoltage condition at the medium-voltage buses will result in a similar undervoltage condition at 480-volt and 120-volt buses and distribution panels. This condition may result in a voltage too low to ensure proper operation of 480-volt and 120-volt safety-related equipment.
- Safety-related motors may be subjected to an overload condition because of the degraded voltage (a motor under a constant load will draw more current when voltage is decreased). If allowed to persist, an overcurrent condition can deteriorate a motor's insulation, possibly affecting its qualified life.

To protect against a degraded grid condition, nuclear plants have additional time-undervoltage relays set to actuate at approximately 90%. If the degraded grid condition lasts for a specified period of time—usually one minute or less—the safety-related motors are tripped and a transfer to the emergency diesel generators (EDGs) is initiated for the Class 1E electrical distribution system.

4.3.1.2 Source Transfer Scheme

Undervoltage relays are used to transfer loads from a normal power source to a backup or emergency power source upon a loss of normal power. The most critical application at nuclear plants is the undervoltage transfer scheme for the Class 1E distribution system. Upon detecting an unacceptable condition, undervoltage relays initiate an orderly transfer of safety-related loads to the plant's EDGs. This transfer scheme is quite elaborate and involves isolation of the Class 1E system from off-site power, automatic start of the EDGs, tripping of large motors, and automatic sequencing to restart vital equipment.

4.3.1.3 Permissive Functions

Instantaneous undervoltage relays are used to block certain actions when voltage is below the dropout setting. For example, an inverter may not allow transfer to an alternate source if the voltage of the alternate source is inadequate. Undervoltage functions are also used in reclosing and underfrequency load shed applications.

4.3.2 Principles of Operation

Microprocessor relays implement function 27 by measuring the magnitude and angle of analog input voltages and converting them to numeric values that can be manipulated arithmetically. When connected to three phase-to-ground voltages, the microprocessor relay is capable of calculating the phase-to-phase voltages as well as the positive, negative, and zero-sequence voltages.



Key Human Performance Point

When connected to three phase-to-ground voltages, the microprocessor relay is capable of calculating the phase-to-phase voltages as well as the positive, negative, and zero-sequence voltages.

In some relays, the three-phase voltage input of the relay is flexible and may be connected to three phase-to-ground voltages (VAN, VBN, and VCN) or to two phase-to-phase voltages (VAB and VBC). Additional single-phase inputs may be available. This single-phase voltage input may be connected to measure the displacement voltage (V_N) or any phase-to-ground voltage or phase-to-phase voltage.

A relay setting must be configured for each flexible voltage input to inform the relay of the type of connection applied.

In applications where the voltage input may include harmonics, it is imperative that the numeric values supplied to the mathematics processor include only the fundamental frequency. This is accomplished via analog or digital filters.

Figure 4-2 shows the logic for a typical microprocessor-based 27 function. The undervoltage protection consists of two definite-time elements (27-2 and 27-1) to allow multiple stages of time-coordinated tripping depending upon the severity of the voltage collapse. When the measured voltage falls below the set point, the 27 picked-up logic element asserts and initiates its associated timer. The pickup/dropout ratio of the 27 element can be set by the user. Voltage thresholds and time delays can be set individually for both elements. An instantaneous undervoltage trip can be configured by setting the associated delay timer to a value of zero.

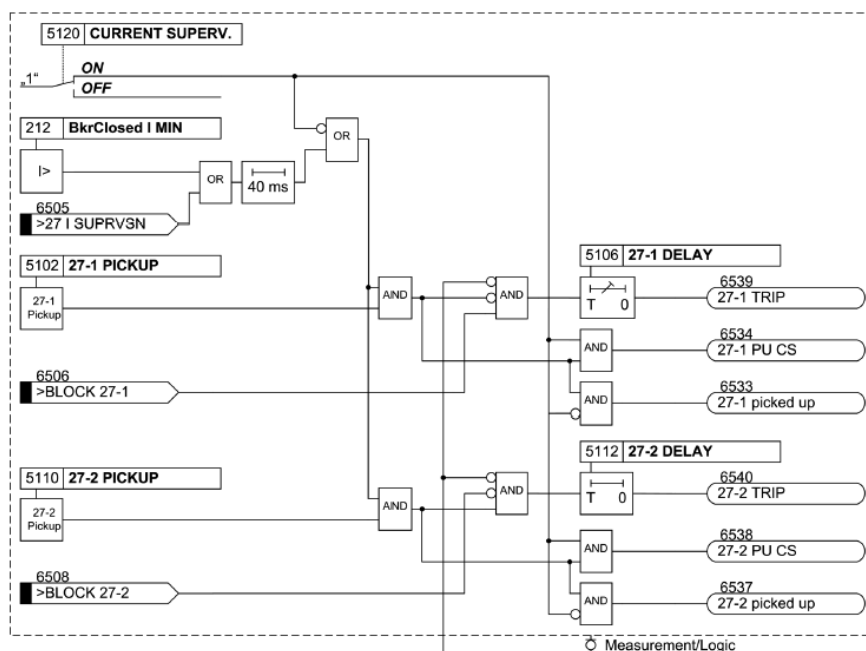


Figure 4-2
Undervoltage Logic (27)

Some models of modern microprocessor relays have integrated programmable logic controller functions. In these relays, the voltage values are available to measurement logic that allows the user to develop custom-built logic applications using the 27 function with any combination of logic gates and outputs.

Key Technical Point



Some models of modern microprocessor relays have integrated programmable logic controller functions. In these relays, the voltage values are available to measurement logic that allows the user to develop custom-built logic applications.

In order to ensure that the protection does not accidentally pick up due to a secondary voltage failure, each stage can be blocked individually or both stages can be blocked in common via binary input(s)—that is, by a voltage transformer miniature circuit breaker (m.c.b.). In addition to this, an integrated fuse-failure monitor blocks both 27 stages (see Figure 4-2).

When first energized, the undervoltage protection must transition from a zero voltage state to nominal voltage. Undervoltage elements must be prevented from tripping during this transition. For this reason, it is recommended that the blocking input of the undervoltage protection be activated via the circuit breaker auxiliary and that the protective function be blocked in this way after a protection trip.

4.4 Directional Power Protection (32F, 32R)

4.4.1 Applications

A directional power relay is generally described in ANSI/IEEE standards as a that operates on a predetermined value of power flow in a given direction.” One example is the reverse power flow resulting from the motoring of a generator upon loss of its prime mover. It is common practice to separate the forward direction from the reverse direction with the capital letter F indicating forward and R indicating reverse. This ANSI function is now commonly integrated into the basic offering of numerical multifunctional generator protection relays. Before multifunctional microprocessor relays, this function was a standalone function in a separate device mounted with other protective functions on the generator control panel door.

Directional units are not usually applied alone, but rather in combination with fault sensors or detectors. Directional sensing has its basis involving relay polarity. Relays that involve interaction between two input quantities from the power system may require polarity indication in order to function properly. At present, there are no standards in this area. Because the polarity is important, the relay manufacturers must specify the polarity markings and clearly document their meaning for proper connections. Relays that sense the direction of power flow at a specific location and, therefore, indicate the direction of the fault, provide a good practical example of relay polarity.

Industrial plants that normally operate with on-site generators paralleled to a utility supply may include a reverse power relay in the utility feeder to detect when on-site generators are supplying power back into the utility power system. Many times contractual obligations require the 32 function to detect this condition and isolate the non-utility generation from the utility system (see IEEE 1547 regarding non-utility generation).

4.4.1.1 Source Power Flow Control

Source power flow control falls into the application of generation of power. A power relay (32) is a type of protection that may be required to detect abnormal power flow, especially if the generators are to operate in parallel with the utility. Power relay elements typically use voltage and current quantities that are essentially in-phase to detect real power or watts. These quantities are stable and do not vary greatly over the few cycles that a fault condition exists. Because they require watts (a calculated value) to make them operate, they are not a very fast means of fault detection.



Key Technical Point

Power relay elements typically use voltage and current quantities that are essentially in-phase to detect real power or watts. Because they require watts (a calculated value) to make them operate, they are not a very fast means of fault detection.

4.4.1.2 Generator Anti-Motoring

Directional power relays are used to provide anti-motoring protection for synchronous generators. Generator motoring results when the prime mover loses its energy source, but the generator remains connected to the power system. The relay detects power flow in the reverse direction (that is, real power flow into the generator rather than out of the generator). Upon detecting reverse power flow, the relay trips the generator and the prime mover (turbine, diesel engine, or gas engine). Special attention should be paid to the type of grounding in this application. Even though disconnected, the generator in rundown state will still feed a ground fault and may destroy the generator.

4.4.1.3 Reverse Power Flow

Reverse power protection is actually for the prime mover and not the generator. When power flows into the generator, the generator draws real power from the system and effectively becomes a motor that tries to drive the prime mover. This operating condition can severely damage steam turbine and engine prime movers. Generator motoring causes steam turbines to overheat due to inadequate steam cooling. Engine generators may suffer mechanical stresses and may even catch fire under severe reverse power conditions.

Some protection schemes for large transmission substations include reverse power relays to detect line-to-ground faults on the primary side of substation transformers. A primary side transformer fault that is inside the upstream isolation device will cause the upstream device to open, but will not isolate the transformer on the secondary side. The reverse power relay is actuated when the transformer becomes energized from the secondary side and power flows back through the transformer into the fault. This relay becomes critical for this type of application.

4.4.2 Principles of Operation

Directional power relays operate similar to watt-hour meters. The power sensed by the relay is a function of voltage magnitude, current magnitude, and phase angle. The numerical relay algorithm emulates the physical model of an electromechanical induction disk directional power relay. Typical operating characteristics for a directional power relay are shown in Figure 4-3.

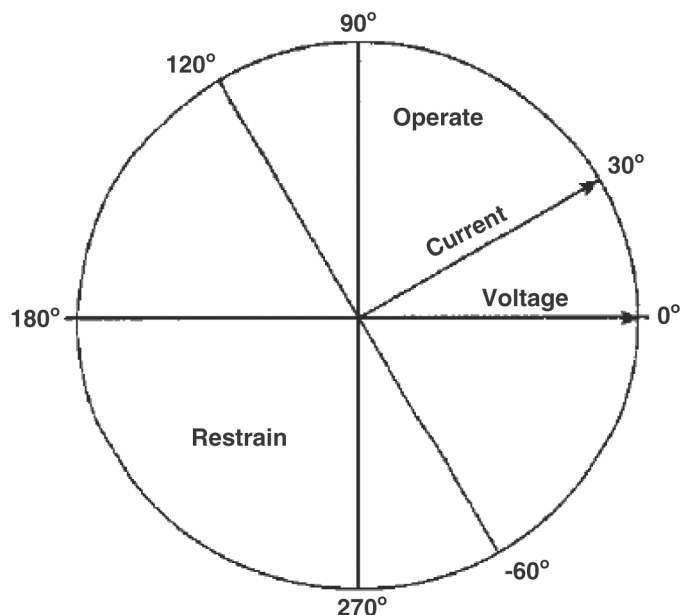


Figure 4-3
Directional Power Relay Operating Characteristics

The phase angle between voltage and current at which the relay is most sensitive is called the angle of maximum torque. At this angle, the least amount of current is needed to pick up the relay. For the unit depicted in Figure 4-3, the angle of maximum torque is 30° (current leading voltage). When the phase angle is between 120° and -60°, the unit will operate if the total measured power is above the established pickup value. When the phase angle is outside the operate range, a restraining force will be exerted on the disk by the coils. Maximum restraint will occur at a phase angle 180° from the angle of maximum torque. The angles at which the relay transitions from operate to restraint are called the zero torque angles because no torque is applied to the relay in the operate or restraint direction.

When very sensitive detection is needed, an induction cylinder unit is used in lieu of an induction disk unit to sense the direction of power flow. The principles of operation for this type of unit are the same as described previously. However, the sensitive induction cylinder is used to control an induction disk unit. The induction disk unit provides a means of obtaining a time-delay response. System voltage is used to provide the motive force for the induction disk unit.

4.5 Undercurrent Protection (37)

4.5.1 Applications

This function can be used for a variety of protection and supervisory tasks. It can serve, for example, as loss-of-load supervision or to recognize disconnected or interrupted lines.

In a capacitor bank application when auto/reclose is desired, the undercurrent element can be used to detect if the capacitor bank current drops below a certain set point before allowing the reclose. In this manner, the relay can be used to prevent the capacitor bank from stress and damage due to reclosing before the capacitor units have had sufficient time to discharge.

4.5.2 Principles of Operation

The three-phase currents are numerically filtered so that only the fundamental wave of the currents is used for the measurement. When one of the phase currents lies below the set threshold, the delay time is started and an output signal is then issued.

The logic diagram of the undercurrent supervision is illustrated in Figure 4-4.

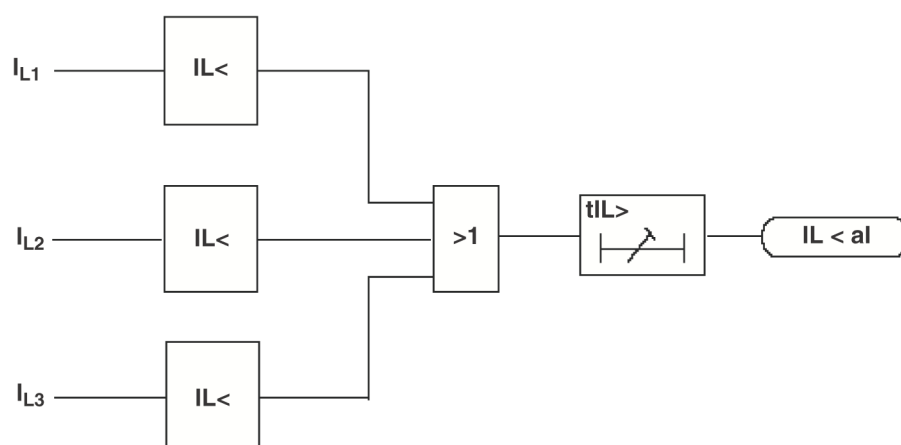


Figure 4-4
Undercurrent Protection Logic

4.6 Loss of Excitation (40)

4.6.1 Applications

Loss of excitation (or field) relays are used to protect generators and, in some cases, very large synchronous motors. Each machine can be operated within certain active and reactive power limits. If the excitation system fails or the machine is operated outside of its specifications, the synchronous generator tends to operate as an induction generator. Under these conditions, the generator obtains its excitation from the system. This situation causes two significant problems—the rotor overheats from induced current and the reactive power flowing from the system to the generator can cause severe system instability. Figure 4-5 depicts a typical machine capability diagram. The machine excitation system is used to operate the machine within these limits.

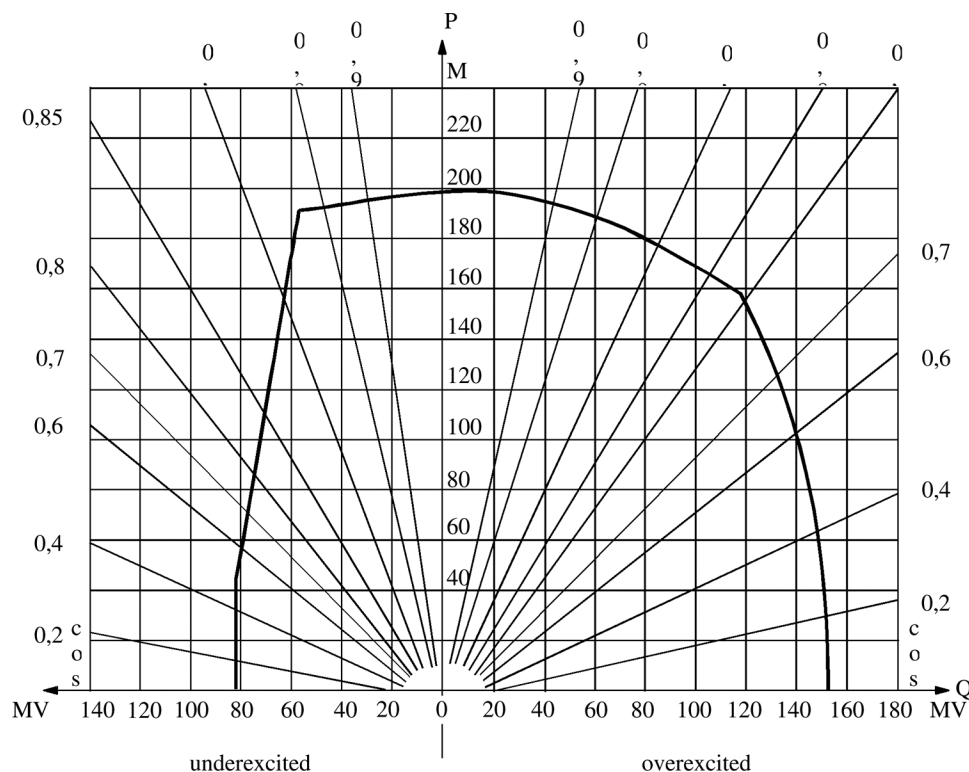


Figure 4-5
Typical Machine Capability Diagram

4.6.2 Principles of Operation

Digital relays use various methods to determine the excitation on a machine. Historically, an impedance relay with an Mho circle was used based on the capabilities of electromechanical relays. Many modern digital relays have adopted the same principle. A loss of excitation relay is no more than an Mho-type distance relay with its operating characteristics modified to detect a voltage-current relationship indicative of a loss of excitation. The Mho circle for a loss of field relay is shown in Figure 4-6. During normal operation, a generator exhibits an overall reactive impedance and operates in the first quadrant of the R-X diagram. When excitation is lost, the measured impedance rotates to the fourth quadrant as shown in Figure 4-6. Some digital relays, however, invert the impedance measurement to the admittance plane. The admittance plane closely resembles the capability diagram of the machine. This type of relay can thus be used to closely supervise the operation of the machine excitation system as shown in Figure 4-5.

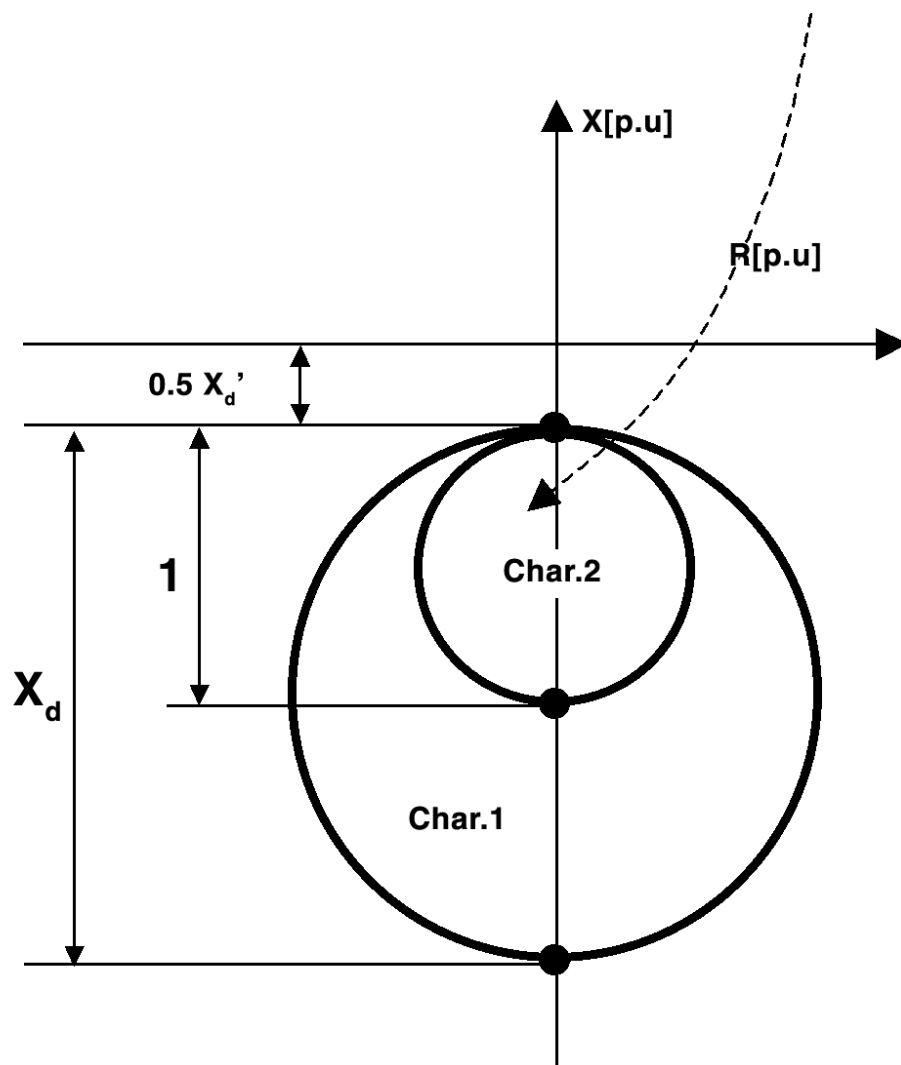


Figure 4-6
Mho Characteristic – Loss of Field

4.7 Phase Unbalance Current Protection (46)

4.7.1 Applications

Phase unbalance protection provides protection to motors, generators, and feeders upon loss of fuse or conductor or from the voltage unbalance that in turn creates current unbalance. Negative-sequence protection can also detect and operate for a reverse-phase-sequence condition (100% negative sequence).

Motors and generators exposed to negative-sequence current produce 120Hz currents (two times the fundamental frequency) that circulate within the rotor and heat the rotor.

Each piece of equipment has specific ratings beyond which the equipment cannot handle the negative-sequence or unbalance current. The negative-sequence or unbalance relay is used to protect the equipment from these conditions. In some applications, the transformers are protected by fuses. At the instance of single-line ground fault, only one fuse opens, allowing negative-sequence current into the transformer. This can be avoided by using a microprocessor relay that has the negative-sequence or unbalance current protection.

4.7.1.1 Motor Protection

Motors or motor feeders usually experience either loss of fuse or loss of conductor. The voltage unbalance also introduces an unbalance current in the motor winding. If the motor is equipped with only overcurrent protection, then single phasing (loss of fuse or loss of conductor) at the motor terminal drives one of the phase current to zero and leaves the other two to sense the overcurrent protection. If the motor is fed from the transformer, and if the transformer source side feeder experiences single-phasing, the current at the secondary of the transformer will not be zero; however, the currents will still be unbalanced. Many high-voltage motors are vulnerable to these unbalanced currents and can sustain serious damage even though the stator currents are small. Negative-sequence protection must be provided in the event of open circuits caused by blown primary fuses, open conductors on overhead distribution lines, or disconnect switches that may not close properly on all three phases. Negative-sequence protection should always be provided for large motors.

4.7.1.2 Generator Protection

The unbalance power system condition produces unbalanced generator voltages. The resulting unbalanced current induces the double-system frequency currents that quickly cause rotor overheating. The ability of a generator to withstand these negative-sequence currents is defined by ANSI C50.13 as $I_2^2 t = k$, where the negative-sequence current is expressed in per unit of the full load current and the time is given in seconds (see Figure 4-7).

The protection offered by the relay should be set to match the $I_2^2 t$ limit of the generator being protected.

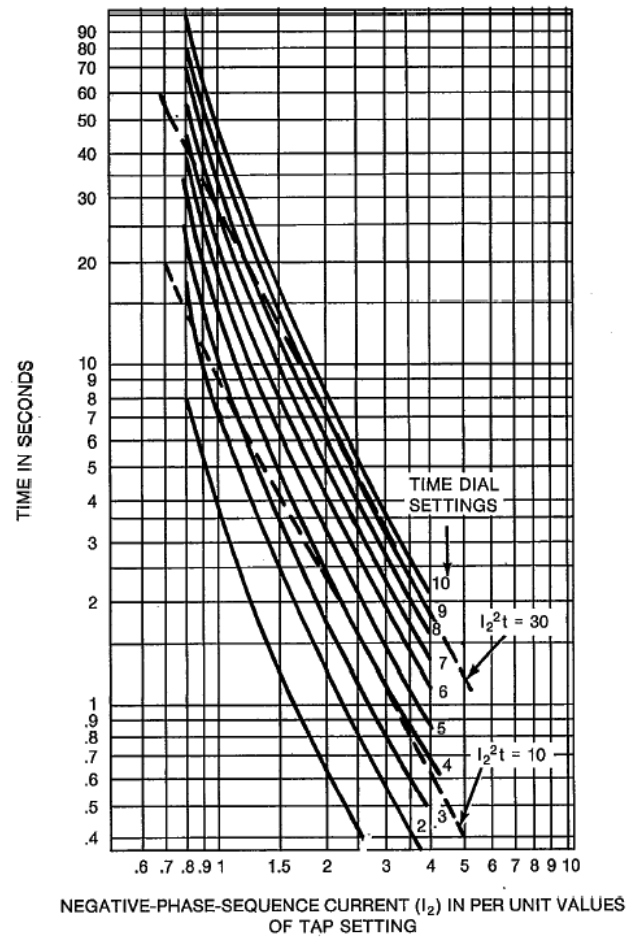


Figure 4-7
Negative Phase-Sequence Current Time Curve

4.7.1.3 Feeder Protection

The feeders (lines and cables) can also be protected by negative-sequence or unbalance protection. This type of protection provides better sensitivity for coordination. The negative-sequence current magnitude under unbalance fault condition is higher than the positive-sequence current magnitude. Negative-sequence protection is recommended for transformer feeders, motor feeders and any other large load feeders.

4.7.2 Principles of Operation

4.7.2.1 Unbalance Current Protection

Unbalance current protection is provided by comparing the values of the two phase currents. If the phase magnitude difference between any two phases is higher than the set value, the protection activates as shown by the following equation:

$$I_a - I_b \text{ or } I_b - I_c \text{ or } I_c - I_a > I_{\text{unbalance}} (\text{setting})$$

4.7.2.2 Negative-Sequence Current Protection

The negative-sequence current protection in a microprocessor relay utilizes the following symmetrical component mathematical formula to calculate the negative-sequence current:

$$I_2 = I_a + a^2 I_b + a I_c$$

4.8 Phase-Sequence Voltage Protection (47)

4.8.1 Application

Incorrect potential transformer (PT) connections during commissioning and failure of phase-reversal switches in power plants can damage motors and generators. These problems can also promote the misoperation of several functions in multifunctional protective relays such as distance, directional overcurrent, and power protection, as well as power measurement that depends on positive voltage for the calculation.

The swapping of phases directly impacts the calculation of positive and negative-sequence quantities and phase-to-phase voltages via the subtraction of one phase-to-ground voltage from another. Ensuring proper phase sequence is vital so that phase detection messages, fault values, and operating measurement values are not falsified.

If the phase rotation reverses during operation (that is, in a pumping power station, the transition from the generator operation to the pumping operation is realized by changing the phase rotation), then a reversal signal at the input, masked for this purpose, is sufficient to inform modern protective relays of the phase-sequence reversal.

4.8.2 Principles of Operation

To detect swapped-phase connections in the voltage input circuits, the phase sequence of the phase-to-phase measured voltages is checked by the voltage monitoring function or phase-sequence voltage protection.

Direction measurement with cross-polarized voltages, path selection for impedance protection, and unbalance load detection all assume a phase-sequence set in the power system data. This group contains certain parameters that are common to all functions.

In modern numerical relays, a phase rotation change can be informed via binary input. When the new condition is detected, a change of phase rotation for the opposite of the parameter in the power system data is performed, thus ensuring that all protective and monitoring functions operate correctly when the phase rotation is reversed.

For applications where the phase rotation of the measured quantities is clockwise, the phase sequence of the phase-to-ground voltage is verified by ensuring the following: V_{L1} leads V_{L2} leads V_{L3} .

For applications where the phase rotation of the measured quantities is counterclockwise, the phase sequence of the phase-to-ground voltage is verified by ensuring the following: V_{L3} leads V_{L2} leads V_{L1} .

Verification of the voltage rotation occurs when each measured voltage is at least as shown by the following equation:

$$|V_{L1}|, |V_{L2}|, |V_{L3}| > 40 \text{ V}/\sqrt{3}$$

If the phase sequence is changed in the relay, phases L2 and L3 internal to the relay are reversed, and the positive-sequence and negative-sequence currents are thereby exchanged.

4.9 Motor Starting Protection

4.9.1 Application

When the digital relay is used to protect a motor, the start-time monitoring feature supplements the overload protection. Start-time monitoring protects the motor against the potential damage that might result from frequent starting or extended starting durations. In particular, rotor-critical high-voltage motors can quickly be heated above their thermal limits when multiple starting attempts occur in a short period of time.



Key Technical Point

When the digital relay is used to protect a motor, the start-time monitoring feature supplements the overload protection. Start-time monitoring protects the motor against the potential damage that might result from frequent starting or extended starting durations.

4.9.2 Principles of Operation

Digital relays use various methods to determine the thermal starting limits of a machine. Typically, the relay will calculate the thermal heat buildup based on the current measured. An I^2t calculation is used in most cases. The digital relay will also use a factor based on the amount of steel in the machine to see how fast the machine will build up heat due to the starting current flowing and also how long it will take the machine to cool down. The machine manufacturer typically supplies these factors.

Digital relays will also provide the capability to count the number of starts during a set period or the time that is allowed between the attempted starts. A digital relay will calculate the starts based on the measured current jumping from zero to a value of at least 10–15% of the machine full load current. The relay will typically apply a trip to the contactor or machine circuit breaker if the number of starts or the time between starts has been exceeded. The relay will reset only after a preset time period. If the relay trips due to the calculated thermal heat build up, the relay will apply a trip and reset only when the relay has calculated a time sufficient for the motor to cool down enough to allow a new start. Figure 4-8 shows the typical starting characteristic of an induction motor.

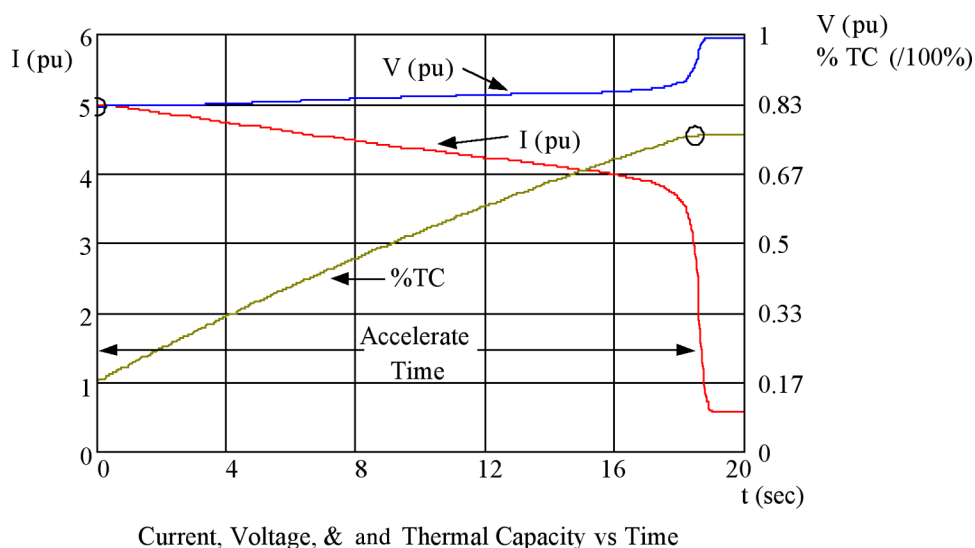


Figure 4-8
Typical Starting Characteristic of an Induction Motor

4.10 Thermal Relays (49)

4.10.1 Applications

Thermal protection prevents damage to equipment caused by thermal overloading, particularly power transformers, rotating machines, power reactors, and cables.

4.10.1.1 Motor Protection

Thermal relays or thermal overloads are used in conjunction with time/overcurrent relays to protect large motors during their entire thermal limit curve. Thermal overloads monitor stator temperature and provide good long-time overload detection. However, they are seldom relied upon to protect against excessive rotor heating or locked rotor conditions. Heat transfer from the rotor to stator is not fast enough to provide a reasonable level of protection against excessive rotor temperatures.

Thermal overloads afford protection against light to medium overloads that do not present an acute problem requiring immediate action. For this reason, the overloads are often configured to initiate an alarm rather than a trip. The decision to alarm or trip is a design tradeoff between operational continuity and motor protection. The more frequent approach is to alarm the overload condition and give operators a chance to correct the problem.

Because of the diversity and accuracy available with overcurrent relays, it is increasingly common to see a combination of time overcurrent relays used to provide overload protection instead of thermal units.

4.10.1.2 Transformer Protection

Thermal overload protection is used on medium and large transformers to detect overheating that can cause insulation damage and shorten the transformer's life. Similar to motor thermal protection, the relays are often used for alarm only to allow operators time to correct the problem. More elaborate schemes may have two settings—one for alarm and one for trip. Microprocessor relays with integrated logic controller functions can utilize data gathered by the relay's thermal protection to control pumps and fans via user-defined logic and the output matrix.



Key Technical Point

Microprocessor relays with integrated logic controller functions can utilize data gathered by the relay's thermal protection to control pumps and fans via user-defined logic and the output matrix.

4.10.1.3 Generator Protection

Thermal overload protection can be used to protect generators from overheating conditions in a manner similar to that discussed for motors.

4.10.2 Principles of Operation

The thermal protection of a typical microprocessor-based transformer relay offers two methods of overload detection:

- Overload calculation using a thermal replica according to an I^2t calculation
- Calculation of the hot spot temperature and determination of the aging of the protected device

4.10.2.1 Overload Protection Using a Thermal Replica

The microprocessor relay's thermal overload protection using a thermal replica can be connected to current circuits on either side of the protected equipment (that is, generator, motor, or transformer). Because the cause of overload is normally outside the protected equipment, the overload current is a through-flowing current (see Figure 4-9).

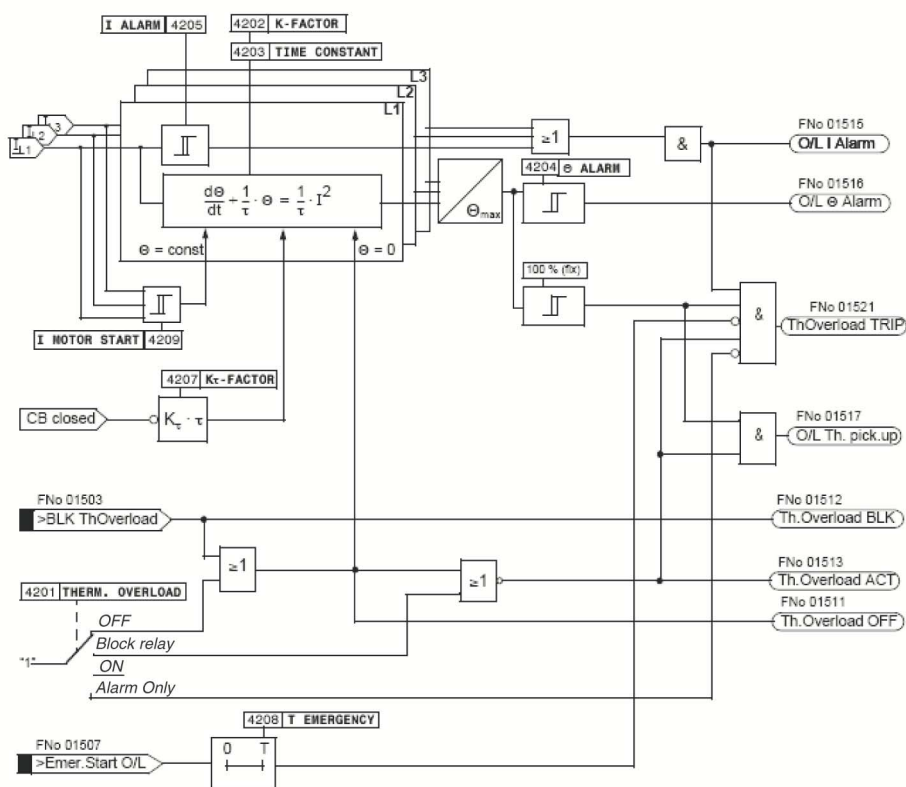


Figure 4-9
Thermal Protection Logic (49)

The microprocessor relay uses the measured current and the thermal time constant data supplied with the protected equipment to compute the temperature rise according to a thermal model.



Key Human Performance Point

The microprocessor relay uses the measured current and the thermal time constant data supplied with the protected equipment to compute the temperature rise according to a thermal model.

An example thermal model is given in the following differential equation:

$$\frac{d\Theta}{dt} + \frac{1}{\tau_{th}} \cdot \Theta = \frac{1}{\tau_{th}} \cdot \left(\frac{I}{k \cdot I_{Nobj}} \right)^2$$

with Θ – actual valid temperature rise referred to the final temperature rise at maximum permissible current of the assigned side of the protected object
 τ_{th} – thermal time constant for heating up of the protected object,
 k – k-factor which states the maximum permissible continuous current, referred to the rated current of the assigned side of the protected object,
 I – currently valid RMS current of the assigned side of the protected object,
 I_{Nobj} – rated current of the assigned side of the protected object.

The solution of this equation under steady-state conditions is an e-function whose asymptote shows the final temperature rise Θ_{end} . When the temperature rise reaches the first settable temperature threshold Θ_{alarm} , which is below the final temperature rise, a warning alarm is given in order to allow an early load reduction.

When the second temperature threshold (that is, the final temperature rise or tripping temperature) is reached, the protected equipment is disconnected from the network. The overload protection can, however, also be set to alarm only. In this case, only an alarm is output when the final temperature rise is reached.

Thermal replicas protect running machines, but several special cases must also be considered. A different thermal time constant exists when self-ventilated machines are at standstill. This case should be considered by the relay's time constant.

Motor startup is another special case where temperature rise may exceed the alarm or even the trip set point. False trips on startup can be avoided by keeping the calculated temperature rise constant while startup current is detected.

When machines must be started for emergency reasons, it may be necessary to allow operating temperatures above the alarm and trip set points during startup and for a brief time after the machine reaches full speed. Microprocessor relay thermal logic alarms and trip outputs can be blocked by providing a binary input during emergency starts. Blocking the alarm and trip output can be accomplished in the relay logic without disabling the thermal model.



Key Technical Point

Microprocessor relay thermal logic alarms and trip outputs can be blocked by providing a binary input during emergency starts.

4.10.2.2 Hot Spot Calculation and Determination of the Aging Rate

Another method used to provide thermal protection involves measuring the hot spot temperature of the protected equipment and the temperature rise caused by transformer load. The temperature of the hot spot is measured using RTD inputs to the microprocessor relay. Temperature rise due to load is measured by current transformer inputs.

The relay calculates the hot spot temperature from these data and the settings of the characteristic properties. When a settable threshold (temperature alarm) is exceeded, an alarm and/or a trip is generated.

4.11 Instantaneous and Time Overcurrent Protection (50/51)

4.11.1 Applications

Instantaneous (50/50N) and inverse-time overcurrent protection (51/51N) are based on phase-selective measurements of the three-phase currents and the ground current in a typical numerical relay having these elements. Multiple definite-time overcurrent and inverse-time characteristics are available in modern numerical relays. The current threshold and the delay time can be set within a wide range of selections and provide extremely accurate set points. Numerical relays also provide the capability for the relay engineer to define custom curves for special applications. Typical curves are shown in Figure 4-10.



Key O&M Cost Point

Multiple definite-time overcurrent and inverse-time characteristics are available in modern numerical relays. Numerical relays also provide the capability for the relay engineer to define custom curves for special applications.

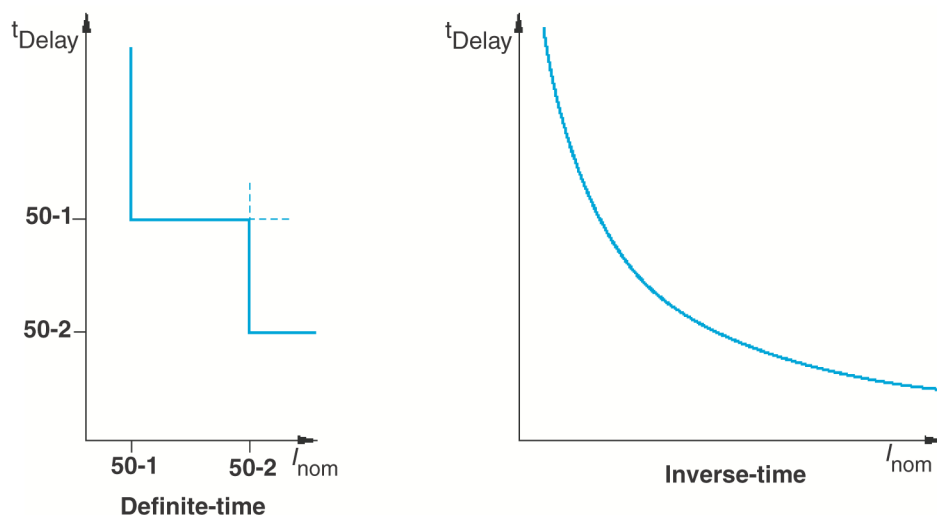


Figure 4-10
Typical Definite-Time and Inverse-Time Delay Characteristic Curves

For ease of time coordination with older electromechanical relays, reset characteristics according to ANSI C37.112 and IEC 60255-3 /BS 142 standards are applied. This provides the capability of using a reset characteristic that emulates the resetting of older electromechanical induction disks. When using the reset characteristic (disk emulation), a reset process is initiated after the fault current has disappeared. This reset process corresponds to the reverse movement of the induction disk unit. Numerical relays also have the capability of instantaneously resetting without delay.



Key Technical Point

For ease of time coordination with older electromechanical relays, reset characteristics provide the capability of using a reset characteristic that emulates the resetting of older electromechanical induction disks.

4.11.1.1 Generator Protection (51V)

Overcurrent protection is used as backup short-circuit protection for the generator. It also provides backup protection for downstream network faults that fail to clear and, therefore, might endanger the generator unit. Numerical relays usually provide the option of configuring overcurrent relay elements on either side of the generator.

Overcurrent pickup on generators due to overload should never occur because the protection may trip if short command times are set. For this reason, a setting equal to 20–30% over the expected peak load is recommended for generators.

In generators where the excitation voltage is taken from the machine terminals, severe faults in the generator and unit transformer zones can cause a loss of excitation voltage. The absence of excitation voltage can lead to a reduction in the fault current supplied by the generator. The fault current may drop below the pickup value of the overcurrent relay within a few seconds. To address this problem, a positive-sequence voltage element is used to control the overcurrent (51V). Two different voltage supervision methods are used to address this application.

Voltage controlled overcurrent (51VC) uses a positive-sequence voltage setting to detect when a fault in the protected zone has reduced the excitation voltage. The output of the positive-sequence voltage enables an additional sensitive overcurrent stage. The 51VC overcurrent is set to remain picked-up for the lower fault current anticipated due to the lower excitation voltage.

Another approach uses a voltage-restrained overcurrent (51VR) that adjusts its sensitivity based on the measured positive-sequence voltage. A lower voltage reduces the pickup of the overcurrent. At 100% excitation voltage, the pickup of the 51VR element is not impacted. When the excitation voltage drops to 50% of nominal, the pickup of the 51VR overcurrent is reduced to one-half of the pickup setting.

In order to prevent an overtrip for faults in the transformer zone, a binary input from the transformer protection may be used to block the 51V function. Because healthy voltages are required to calculate the positive-sequence quantity, fuse failure detection should defeat the 51V protection.

4.11.1.2 Motor Protection

Overcurrent protection is required for short-circuit protection and is a minimum requirement for all motor protection schemes. Overcurrent pickup for motors has a recommended setting equal to 40% over the expected peak load of the motor.

4.11.1.3 Transformer Protection

Smaller transformers (typically <10MVA) use overcurrent elements for both phase and ground protection. For higher rated transformers, overcurrent protection is used as backup protection. Overcurrent pickup for transformers has a recommended setting equal to 125–200% of the rating of the transformer.

4.11.1.4 Bus Protection

A variety of protection schemes can be used to protect busses. One simple scheme uses bus overcurrent protection that protects for overload conditions. Overcurrent differential is another scheme that can be used for bus protection.

With modern numerical relays, new applications have been introduced. One of these applications relates to bus protection and is described as a reverse interlocking scheme. Use of this scheme

reduces the amount of relays required because feeder relays interface with source relays to determine whether the fault is on the bus or if it is beyond the bus, therefore eliminating the need for bus protection.

4.11.1.5 Feeder Protection

Feeder circuits use overcurrent protection as the primary form of protection. A single microprocessor relay provides all of the elements necessary to replace the three-phase relays and ground electromechanical relay typically used to protect the equipment connected to the feeder. Standard ANSI characteristics are used when applying settings on feeders.

4.11.1.6 Backup Protection

Levels of protection depend on customer protection philosophies, regulating authorities, or regional authorities. Typically, phase overcurrent protection applies on lower voltage equipment and the ground protection can be classified as backup protection. On larger equipment such as generators or large motors, both the phase and ground protection may be considered as backup due to the use of faster operating protection specifically designed for protecting units.

4.11.2 Principles of Operation

Numerical overcurrent relays use the phase-selective measurements of the three-phase currents and the ground current to detect an overload or fault condition. Multiple elements may be available to operate on a definite-time or inverse-time delay. Definite-time elements are used for high magnitude faults with short tripping delays. Time delays can range from an instantaneous to a settable delay time. ANSI/IEEE define inverse-time element characteristics as inverse, short, long, moderately, very inverse, and extremely inverse. In addition to predefined time characteristics, numerical relays also include features that allow for user-defined characteristics and can typically be defined separately for both phase and ground.

In retrofit applications, numeric 50/51 elements may need to coordinate with electromechanical relays. To coordinate with the reset of electromechanical induction disk relays, most numerical relays contain an algorithm that emulates the physical reset of an electromechanical time overcurrent disk according to ANSI/IEEE Standard C37.112. Most numerical relays offer the user a choice of instantaneous reset or disk emulation reset as a settings parameter. With these options, numerical relays can coordinate on pickup and dropout with all types of electromechanical and numeric relays from electromechanical hinged armature and plunger types to electromechanical induction disk relays.

4.12 Overvoltage Protection (59)

4.12.1 Applications

4.12.1.1 Bus Protection

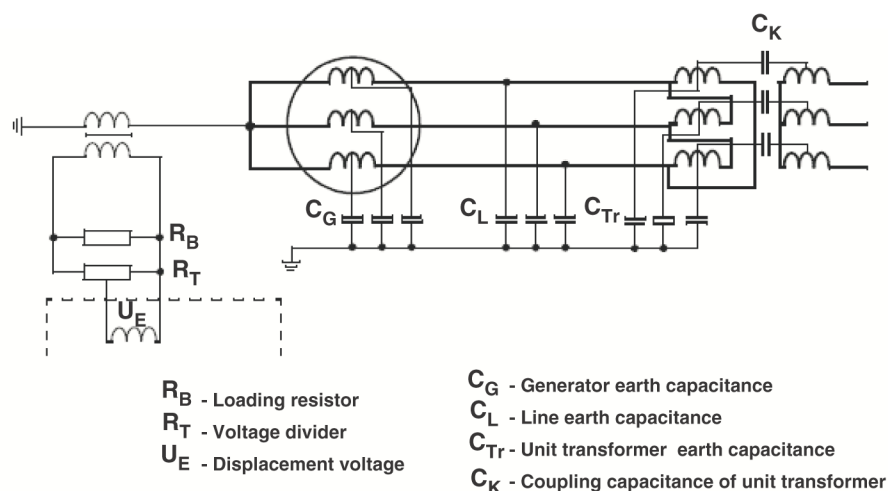
The function of overvoltage protection is to protect electrical machines and associated equipment against inadmissible overvoltage conditions that may cause insulation damage.

The overvoltage protection for a bus usually has two elements. In the case of a high overvoltage, tripping is performed with a short-time delay. In the case of less severe overvoltage, an alarm is annunciated or the trip is performed with a longer time delay.

4.12.1.2 Generator Ground-Fault Protection

The stator earth fault protection detects earth faults in the stator windings of three-phase machines. The machine can be operated in busbar connection (directly connected to the network) or in unit connection (via unit transformer). The criterion for the occurrence of an earth fault is mainly the occurrence of a neutral displacement voltage. This principle results in a protected zone of 90–95% of the stator winding.

The displacement voltage (V_E) can be measured at the machine neutral via a neutral grounding (earthing) transformer (Figure 4-11) or via voltage transformers connected in broken delta.



Unit Connected Generator with Neutral Earthing Transformer

Figure 4-11
Unit Connected Generator With Neutral Grounding (Earthing) Transformer

The device calculates the displacement voltage from the phase-to-ground voltages if the displacement voltage cannot be directly applied to the device.

In many displacement voltage formations, the components of the third harmonic in each phase are summed because they are in phase in the three-phase system. In order to obtain reliable measured quantities, only the fundamental of the displacement voltage is evaluated in the stator earth fault protection. Harmonics are filtered out by numerical filter algorithms.

The evaluation of the displacement voltage is sufficient for machines in unit connection. The achieved sensitivity of the protection is limited only by power frequency interference voltages during an earth fault in the network. These interference voltages are transferred to the machine side via the coupling capacitances of the unit transformer. If necessary, a loading resistor can be provided to reduce these interference voltages. The protection initiates disconnection of the machine when an earth fault in the machine zone has been present for a set time.

4.12.1.3 Capacitor Bank Unbalance Protection

Capacitor bank voltage unbalance is detected through neutral-to-ground voltage increments caused by isolation of faulted capacitor units from the bank by their respective fuses. Short-circuit protection for the individual capacitor units is furnished by fuses that clear internal faults, minimizing the probability of capacitor case ruptures.

Special consideration may be taken in ungrounded banks when a capacitor fuse blows. A rise of the voltage across the remaining capacitors on the phase in which the fuse has opened may cause serious damage in these units. Capacitor unit life is shortened dramatically because of the compounding of the overvoltage stress on the remaining units (see Figure 4-12).

When a predefined neutral-to-ground voltage is reached, the protective device can provide an alarm or directly disconnect the entire bank.

Number	Indication	Value	Date and time	Initiator	Cause	State	Add Cause
00301	Power System fault	11 - ON	08.08.2004 14:09:23.329				
00302	Fault Event	11 - ON	08.08.2004 14:09:23.329				
00501	Relay PICKUP	ON	0 ms				
01761	50(N)/51(N) O/C PICKUP	ON	0 ms				
01765	50N/51N picked up	ON	0 ms				
01837	51N picked up	ON	0 ms				
01763	50/51 Phase B picked up	ON	11 ms				
01820	51 picked up	ON	11 ms				
01834	50N-1 picked up	ON	11 ms				
01831	50N-2 picked up	ON	11 ms				
01810	50-1 picked up	ON	32 ms				
01800	50-2 picked up	ON	32 ms				
00511	Relay GENERAL TRIP command	ON	32 ms				
01791	50(N)/51(N) TRIP	ON	32 ms				
01805	50-2 TRIP	ON	32 ms				
00533	Primary fault current Ia	0.00 kA	62 ms				
00534	Primary fault current Ib	1.00 kA	62 ms				
00535	Primary fault current Ic	0.00 kA	62 ms				
01124	Fault Locator Loop BG	ON	51 ms				
01118	Ft Locator: secondary REACTANCE	2.96 Ohm	51 ms				
01119	Ft Locator: Distance to fault	61.2 Miles	51 ms				
01833	50N-2 TRIP	ON	111 ms				
01836	50N-1 TRIP	ON	511 ms				
01815	50/51 b TRIP	ON	531 ms				
01839	51N TRIP	ON	667 ms				
01810	50-1 picked up	OFF	6423 ms				
01800	50-2 picked up	OFF	6423 ms				
01763	50/51 Phase B picked up	OFF	6433 ms				
01820	51 picked up	OFF	6433 ms				
01765	50N/51N picked up	OFF	6443 ms				
01834	50N-1 picked up	OFF	6443 ms				
01761	50(N)/51(N) O/C PICKUP	OFF	6443 ms				
01837	51N picked up	OFF	6444 ms				
01831	50N-2 picked up	OFF	6444 ms				
00301	Power System fault	11 - OFF	08.08.2004 14:09:23.774				

Figure 4-12
Ungrounded Capacitor Bank Blown Fuse Overvoltage Condition

4.12.2 Principles of Operation

By means of the overvoltage protection feature for machines, the user can select to monitor the phase-to-phase voltages or the phase-to-ground voltages. In the case of a high overvoltage, the trip is performed with a short time delay.

For special applications, some numerical relays also calculate the positive-sequence and negative-sequence system voltages. The symmetrical components are also monitored and can be combined according to the user's requirements. They can be switched on or off separately or used for alarm purposes only. In the latter case, the respective trip commands do not appear.



Key Technical Point

Some numerical relays also calculate the positive-sequence and negative-sequence system voltage. Therefore, the symmetrical components are also monitored and can be combined according to the user's requirements.

Most numerical relays for feeders with three-phase connections require the phase-phase voltages. If necessary, they can be calculated from the phase-to-ground voltages. In the case of monophaserelays, the measured voltage is directly used for protection. When the voltage on an overvoltage relay is above the relay's pickup point, a timer is started, and the relay issues a trip command after an established time.

4.13 Voltage Balance Protection (60FL)

4.13.1 Application

Voltage balance was used in the past as a reliable method to detect fuse failure on electromechanical systems. It was essential to immediately block the functions that were affected by the failure of a fuse. Electromechanical impedance relays used potential as a restraining quantity. The impedance relay would trip under fuse-failure conditions if the load increased to the operating characteristic of the relay. The voltage balance method compared two PTs for any differential voltage on a given phase.

Digital relays can, however, reliably detect fuse-fail conditions using a combination of voltage and current measurements. When a fuse failure is detected, the associated and affected protection functions are blocked.

There are no requirements for a voltage balance relay in a modern protection system. See Section 5 of this report for a discussion of protection system design.

4.14 Sudden/Fault Pressure Relays (63)

4.14.1 Applications

A transformer greater than 500 kVA is typically equipped with a sensitive pressure switch that detects a sudden change in gas or oil pressure within the transformer. Sudden pressure relays (SPRs) operate with sudden gas pressure changes and are usually mounted at the top of the transformer. Fault pressure relays (FPRs) operate with a sudden oil pressure change and are typically mounted low or in other locations on the transformer.

A pressure relay device supplemental differential protection and offers very sensitive protection against internal transformer faults. Although the pressure relay is not a protective relay in the classical sense, these devices are part of the overall protection scheme.

New relay designs now include connections using numerical relay binary inputs and outputs wired to remote SPR or FPR contacts to monitor operation, capture fault events, and signal remote operation. This allows for station operators to respond more quickly and efficiently compared to older schemes where remote lockouts and switches were used to flag a pressure operation.

**Key O&M Cost Point**

New relay designs now include connections using numerical relay binary inputs and outputs wired to remote SPR or FPR contacts to monitor operation, capture fault events, and signal remote operation. This allows for station operators to respond more quickly and efficiently compared to older schemes where remote lockouts and switches were used to flag a pressure operation.

4.14.2 Principles of Operation

Pressure relays contain a pressure sensing element that responds to sudden internal pressure changes in a power transformer. Arcing caused by a turn-to-turn or phase-to-ground fault causes a rapid increase in the internal pressure of a faulted transformer. If the pressure changes at a quick rate, the sensing contact of the pressure relay is designed to close and trip the transformer off-line. Sudden pressure relays or fault pressure relays are generally provided as an integral part of the transformer protection on larger transformers. .

4.15 Stator/Rotor Protection**4.15.1 Applications**

The electrical components of a modern generating unit consist of the generator stator winding with its associated unit transformer and a rotating field (rotor) with associated field windings and excitation system.

The stator neutral is usually grounded through a resistor (for smaller units) or by connecting the neutral point of the stator to ground through the primary of a distribution transformer. A loading resistor is then placed across the secondary of the transformer. Ground-fault protection can be applied by measuring the current on the transformer secondary or by a voltage unit that measures imbalance voltage across the loading resistor.

The methods of stator ground-fault protection using 60 Hz voltage or current are capable of providing protection for only 90–95% of the stator winding. Third harmonic voltage schemes (27/59) and low-frequency injection schemes (64G) are capable of achieving 100% percent stator ground protection.

**Key Human Performance Point**

The methods of stator ground-fault protection using 60 Hz voltage or current are capable of providing protection for only 90–95% of the stator winding. Third harmonic voltage schemes (27/59) and low-frequency injection schemes (64G) are capable of achieving 100% percent stator ground protection.

Rotor ground-fault protection is used to detect ground faults in the excitation circuit of synchronous machines. The rotating field and excitation system of a generator is an isolated DC circuit. A single ground on this system will not cause fault current to flow. The danger to the rotor and excitation system occurs when a second ground occurs at a different point in the winding. This represents a winding short circuit of the excitation circuit. Magnetic unbalances can occur, resulting in extreme mechanical forces that can lead to the destruction of the machine. The rotor can be protected against ground faults by using AC or DC voltage injection methods.

4.15.2 Stator Ground Protection (100%) With Third Harmonics (27/59)

Under normal conditions, a third harmonic voltage is produced by the generator between the stator neutral point and ground. By contrast, the third harmonic voltage at the generator terminals is low during normal conditions. During a ground fault, the third harmonic in the neutral drops to near-zero while the third harmonic at the generator terminals increases. If present in sufficient magnitude, the microprocessor relay is able to measure the third harmonic voltage content and to determine if a fault is present on the stator.

Microprocessor relays are flexible enough to adapt to several different third harmonic potential sources. Direct measurement of the third harmonic voltage can be made by connecting the relay's voltage input across the loading grounding resistor of a small unit or across the resistor on the secondary of a stator neutral grounding transformer. It is also possible to configure microprocessors to calculate the third harmonic content of the displacement voltage from three phase-to-ground voltage inputs.

Third harmonic measurement detects faults that occur near the neutral point of the stator and those that occur near the generator terminals. There is a point (typically between 20–30% of the distance from the winding neutral point to the generator terminals) where pre-fault and post-fault third harmonic levels are approximately equal. This effectively creates a blind spot in the winding protection. This blind spot can be avoided by combining the third harmonic protection with fundamental frequency 90% stator ground protection or by using the 20 Hz voltage injection method.

4.15.3 Stator Ground Protection (100%) With Subharmonic (20 Hertz) Voltage Injection (64G)

Refer to the typical connection diagram shown in Figure 4-13. An external low-frequency alternating voltage source (20 Hz) is injected into the generator neutral (voltage max 1% of the rated generator voltage). If a ground fault occurs in the stator, the 20 Hz voltage drives a current through the fault resistance. From the driving voltage and the fault current, the protective relay determines the fault resistance.

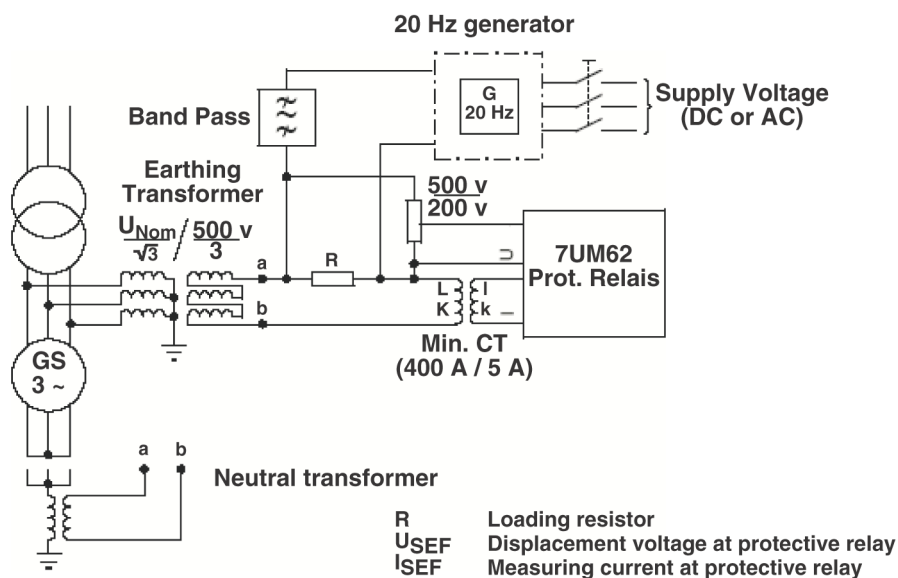


Figure 4-13
Typical Circuit Design of 100% Stator Ground-Fault Protection Using 20Hz Voltage Injection

During a ground fault, the microprocessor relay measures the 20 Hz current and voltage to calculate the fault resistance. If the stator ground-fault resistance drops below the set point, the 100% stator ground-fault logic is asserted. An associated timer is provided to delay the trip output if desired.

This scheme provides highly effective ground-fault protection for 100% of the stator while the machine is running at standstill and deenergized or on turning gear. The protection principle described here also detects ground faults at the generator terminals, including connected components such as voltage transformers.

4.15.4 Rotor Ground-Fault Protection (64R) –AC Voltage Injection

The AC voltage injection method of rotor ground-fault protection uses an external auxiliary voltage of approximately 36–45 V AC. Refer to Figure 4-14 for a typical application. This voltage is symmetrically coupled to the excitation circuit via the capacitors of a coupling unit and simultaneously connected to the measurement input of the microprocessor relay. The capacitors limit the magnitude of the current and block the normal field voltage to prevent a large

DC current from flowing in the transformer. The coupling capacitors are protected from high-fault currents by series resistors. If high harmonic currents are expected (that is, excitation by thyristor circuits), an additional choke filter may be added to limit the current.

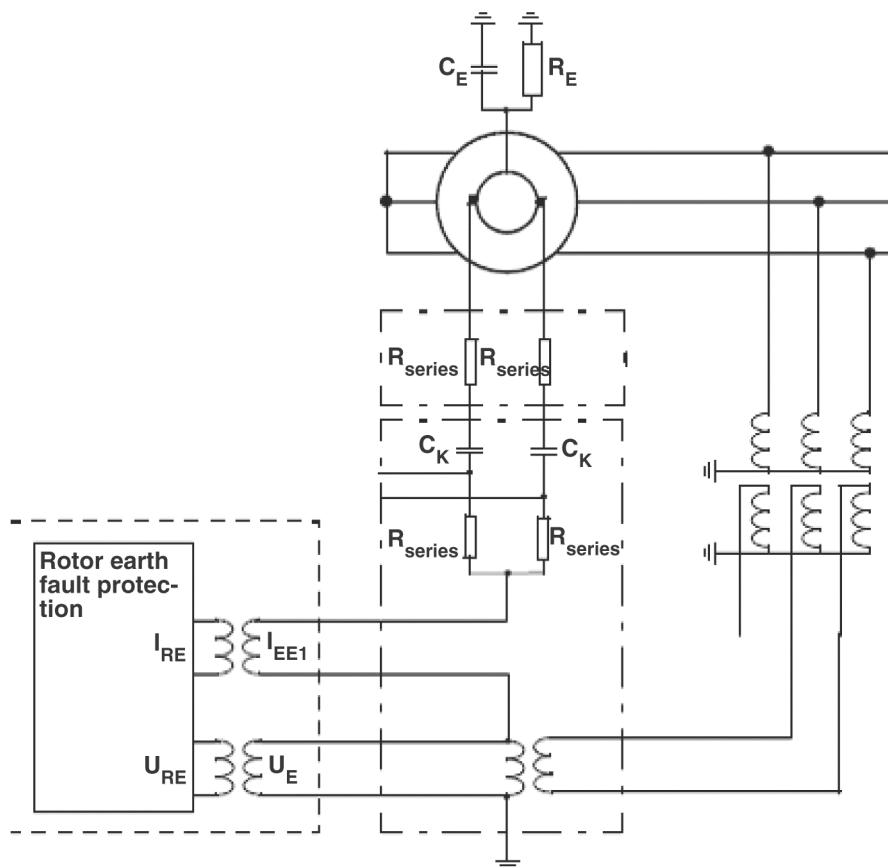


Figure 4-14
Typical Circuit Design of Rotor Ground-Fault Protection Using Voltage Injection

The auxiliary AC voltage drives a small charging current through the coupling unit, brush resistance, and capacitance to ground (earth) of the excitation circuit. This current I_{RE} amounts to only a few mA during normal operation and is measured by the relay.

The rotor ground-fault calculation calculates the complex ground impedance from the auxiliary AC voltage V_{RE} and the current I_{RE} . The ground resistance R_E of the excitation circuit is then calculated from the ground impedance. The ground resistance supervision has two stages. Usually an alarm is initiated if the ground resistance falls below an initial high-resistance stage. If the value falls below the second low-resistance stage, tripping will be initiated after a short time delay.

This scheme offers effective rotor ground-fault protection while the machine is running, at standstill and deenergized, or on turning gear.

4.16 Directional Overcurrent Protection (67/67N)

4.16.1 Applications

4.16.1.1 Line/Feeder Protection

Directional overcurrent protection allows the application of numerical relays to systems where coordination of the protection depends on knowing both the magnitude of the fault current and the direction of energy flow to the fault location. Numerical relays can be set to look forward or reverse with a selectable setting.

To determine the direction for a single phase fault, numerical relays compare the faulted phase current to the corresponding unfaulted phase-to-phase voltage. The unfaulted voltage also allows an unambiguous direction determination if the fault voltage has collapsed severely (short-line fault). With three-phase faults, stored voltage values are used to clearly determine the direction if the measurement voltages are not sufficient.

For ground directional elements, numerical relays can compare zero-sequence quantities from a measured ground current or calculated ground current to a measured $3V_0$ voltage or calculated ground voltage. Another method available in numerical relays is the comparison of negative-sequence current to negative-sequence voltage. This method is advantageous when parallel lines exist and the zero-sequence current is influenced or the zero-sequence voltage becomes very small due to unfavorable impedances.

4.16.1.2 Generator Protection

Generator-sensitive ground-fault protection is an example of directional overcurrent protection. In order to ensure that pickup occurs with even internal faults, sensitive ground-fault overcurrent protection for generators is usually connected to the current transformer set in the neutral leads of the unit. A sensitive high-set instantaneous unit combined with a short-circuit direction determination will ensure that the generator will be isolated if a short circuit occurs.

4.16.2 Principles of Operation

Directional overcurrent relays are designed to operate on overcurrent conditions only when power flow is in a specified direction. This allows the relays to discriminate between faults ahead of or behind the relay. The direction of power flow is determined by measuring the phase angle between voltage and current. The phase angle is dependent upon the direction of current flow in relation to the monitored voltage.

4.17 Out-of-Step Function (78)

4.17.1 Applications

A sudden change of load in the power system network caused by a fault, a disconnection of loaded lines, or an auto-reclose forces the generators to adjust to this new load condition. The adjustment will not happen in a jump step due to the mass of the generators, but rather as an oscillation. Normally, it will be a dampened oscillation and the generators will be able to return to a normal state. In some cases, the swing is so large that the generators lose synchronism, run out-of-step, and overload. It is desirable to detect this situation and to disconnect the generator from the transmission network.

Power swings are three-phase symmetrical occurrences. Therefore, the symmetry of the currents can be verified by evaluating the negative and/or the negative-sequence currents.

4.17.2 Principles of Operation

For the detection of an out-of-step situation, the trajectory of the complex impedance vector is evaluated. The trip decision is made on the rate of change of the impedance vector and the location of the electrical center of the power swing. In the case of an out-of-step condition, the measured impedance will travel on a trajectory in the R/X plane with a speed that is much less than that caused by a fault. The time taken by the impedance trajectory to enter and leave the out-of-step characteristic is measured. In the event of a slow-moving power swing trajectory, the measured time exceeds the timer setting. In the event of a fault, the impedance trajectory will quickly jump to a point close to the generator. The generator should be tripped only if the electrical center of the power swing frequency is close to the generator. The reach of the out-of-step characteristic should not exceed 90% of the step-up transformer. This characteristic can be an Mho circle or a quadrilateral characteristic. In some applications, it is also desirable to disconnect the generator when the electrical center is in the transmission network. In this case, the reach setting should be determined accordingly.

Additionally, to detect the out-of-step situation, the impedance vector must enter the characteristic on one side and leave on the other side. This is characterized when the real component of the impedance has changed its sign while passing through the characteristic as shown in Figure 4-15.

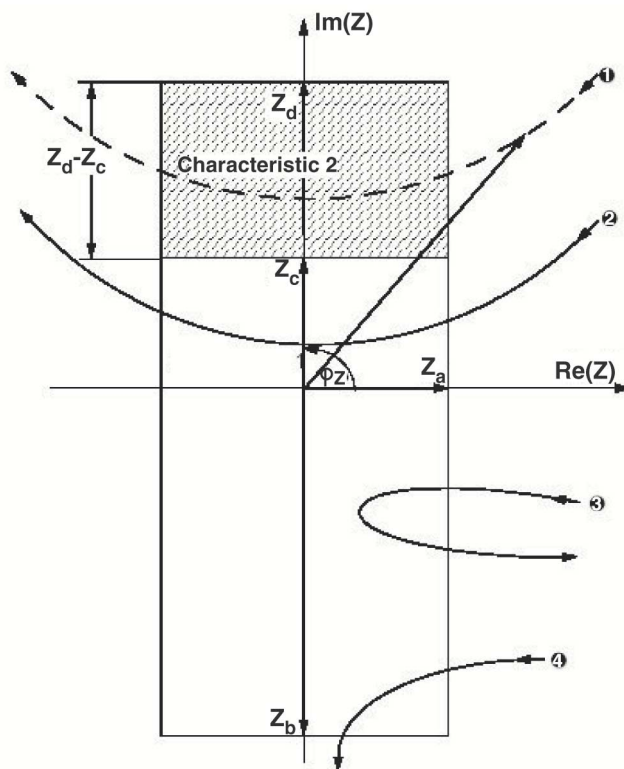


Figure 4-15
Quadrilateral Out-of-Step Characteristic

After the out-of-step situation is detected, the generator can be disconnected from the network. If the electrical center is close to the generator because of the stress for the generator, only one or two slip cycles may be allowed before the trip command is issued. If the electrical center is in the transmission network, more slip cycles can be tolerated.

4.18 Frequency Protection

4.18.1 Applications

The frequency relay provides protection so that machines and systems may fully operate within their capability.

The machines experience higher or lower speed depending upon the frequency. In typical applications, the frequency relays are used to control (balance) the load requirement and available system output. The generators must be equipped with frequency protection in order to adjust the output according to system demands.

The frequency relays have a predetermined limit set in cycles/second. Any deviations from this predetermined limit can trigger the frequency protection. Triggering of frequency protection

above the predetermined limit is called overfrequency. Triggering of frequency protection below the predetermined limit is called underfrequency.

4.18.1.1 Underfrequency

Underfrequency occurs when the system is overloaded with demand. This happens when a large load is suddenly brought on-line or the loading requirement of a system gradually increases over time. (For instance, the loading requirement is highest on a summer afternoon.)

In the overloaded condition, the system as a whole (all generators) is trying to supply the increased load by raising the output of the generators. This causes the generator to slip from its nominal frequency and, therefore, to create the underfrequency. The underfrequency function trips the generator before it falls out of synchronization with the rest of the system.

Load shedding is used whenever the load demand is higher than the total generation on the system. Load shedding is discussed in detail in Section 4.18.1.3.

The generator turbine and its blades are affected by the change in the frequency much more than the generator itself. Therefore, when determining the setting for the frequency protection, one must look at the turbine capability (see IEEE C37.106).

4.18.1.2 Overfrequency

Overfrequency normally occurs when the system has excessive generation compared to the demand or load. This can be a drastic or gradual change in the system load. Under fault conditions, one or more loads are isolated from the system, leaving the system with excessive generation. Excessive generation can also happen when the system demand decreases (at night, for example). To avoid the frequency from drastically increasing, the peaking generators are taken off-line to adjust to the system load. This protection is also used in conjunction with overvoltage protection to provide overexcitation protection for generators and transformers.

4.18.1.3 Frequency Load Shedding

The overload condition causes the generators to slow down and the frequency to drop. Load shedding is utilized to trip predetermined (low-priority) load from the system while keeping the critical load running (see Figure 4-16). More than one level of underfrequency can be used to permit a number of steps for load shedding as necessary. The number of load-shedding steps, the frequency setting for each step, and the amount of load shed at each step should be decided by a system study. The priority must also be decided so that the lowest priority load is taken off first. Even though it is seldom used, the overfrequency relay can also be used to bring the load back. The same priority used for load shedding should be used when the load is restored.

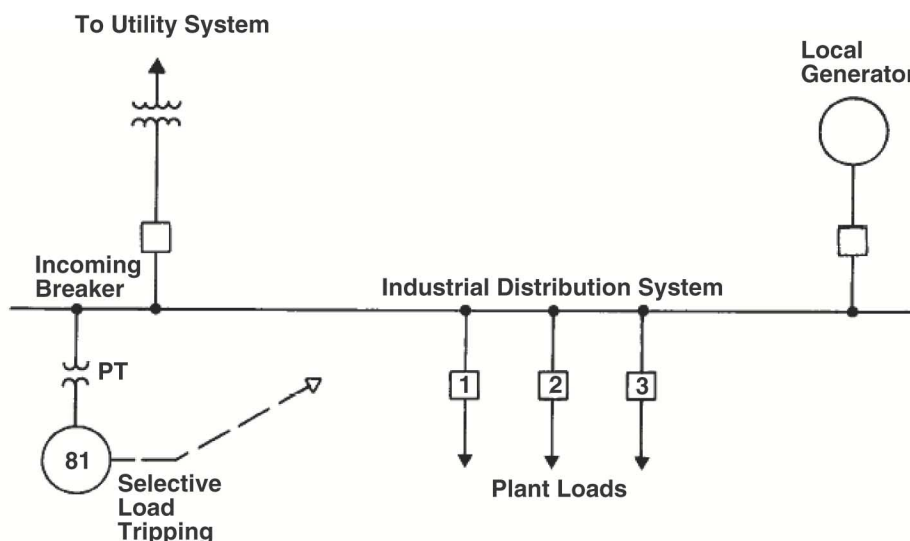


Figure 4-16
Frequency Load Shedding

4.18.2 Principles of Operation

Implementing frequency protection is relatively simple in microprocessor relays. The relay has the filtered information about the power system voltages and currents readily available. The relay utilizes mathematical equations to calculate the frequency of the power system. Once calculated, it compares the measured frequency with the predetermined set point.

The microprocessor relay can be equipped with four (and as many as six) stages of over/under frequency. The measured frequency is compared with all set points within the frequency element. An output can be triggered if the measured frequency is below or above one of the set points.



Key Technical Point

The microprocessor relay can be equipped with four (and as many as six) stages of over/under frequency.

The underfrequency element is sometimes supervised by voltage transformer fuse failure. The frequency protection becomes inactive under fuse failure of the voltage transformer.

4.19 Lockout Relays (86)

4.19.1 Applications

Lockout relays are not actually protective relays; however, they are used in conjunction with protective relays and are briefly discussed here for completeness. A lockout relay is a high-speed, manual, or electrically reset auxiliary relay that is used to provide contact multiplication. It responds to a trip signal provided by a protective relay to trip and lockout several breakers at once. A typical bus-fault protection scheme may include a bus differential relay that sends a trip signal to a lockout relay, which in turn initiates a trip of all source and feeder breakers to isolate the faulted bus. Normally closed lockout contacts may also operate to defeat the closing circuits of all tripped devices. Following a protective action, the lockout relay must be reset before any of the affected circuit breakers can be closed.

4.19.2 Principles of Operation

Traditional lockout relays may be used in conjunction with microprocessor relays or virtual lockouts may be integrated into the microprocessor relay using the programmable logic controller feature of the relays. Lockout relays are easily reproduced within the tripping matrix using binary inputs or internal protection logic to provide trip initiation, set/reset flip-flops or latching logic gates to provide the lockout feature, and binary outputs that are programmable through the tripping matrix to provide isolated contact multiplication. The tripping matrix makes it easy to program LED alarms (that indicate the state of the lockout) and programmable pushbuttons (that reset the virtual lockout). The integration of lockout functions into microprocessor relays with logic controller functions helps to reduce required panel space, wiring, and installation labor.



Key Human Performance Point

Virtual lockouts may be integrated into the microprocessor relay using the programmable logic controller feature of the relays.

4.20 Differential Relays (87)

4.20.1 Applications

4.20.1.1 Transformer Protection

Differential protection is preferred for transformers over 10 MVA. The differential scheme is set up to detect faults within the transformer's zone of protection. Because differential relays operate on the net difference of current flowing into and out of the zone of protection, transformer differential relays should not actuate on a through-fault (that is, a fault on a downstream feeder outside of the transformer's zone of protection).

Differential protection is based on current comparison. It makes use of the fact that the current into a protected equipment (Figure 4-17) always equals the current out of the protected equipment during healthy operations (assume equal transformer ratios). This current I (dashed line of Figure 4-17) flows into one side of the protected zone and leaves it on the other side. The differential current measurement algorithm (represented by differential element M in Figure 4-17) generates the numeric differential (or operating) current by measuring the current I supplied by each CT, mathematically correcting for differences in angle and magnitude caused by the CT's secondary connections and CT taps, and calculating the vector sum of $I_1 + I_2$.

The vector sum of $I_1 + I_2$ is equal to zero for healthy conditions (that is, load current or an external through-fault condition).

For internal faults in the transformer zone, one current reverses direction, generating a differential current $I_1 + I_2$ (indicated by the solid lines in Figure 4-17). As a result, the simple circuit shown in Figure 4-17 ensures a reliable tripping of the protection if the fault current flowing into the protected zone during a fault is high enough for the differential element M to respond.

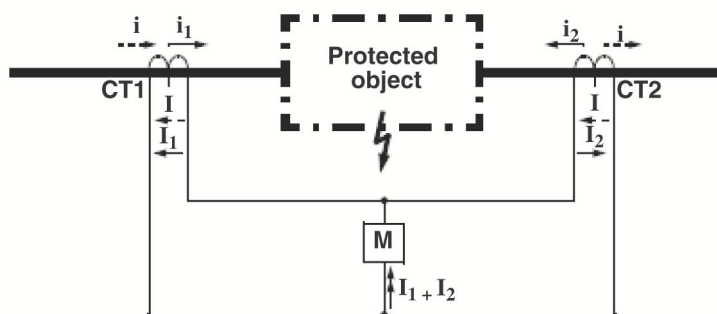


Figure 4-17
Operation of Differential Protection

When external faults cause a heavy current to flow through the protected zone, current transformers CT1 and/or CT2 may saturate. As a result, a significant operate current is calculated by differential element M . If the magnitude of this erroneous operate current is greater than the differential setting, the protection will incorrectly issue a trip signal for the through-fault even though this fault is outside the protected zone.

Percentage differential relays prevent this by calculating a restraint current quantity, which is normally derived from the current difference $|I_1 - I_2|$ or from the arithmetical sum $|I_1| + |I_2|$, or by the equation $\frac{|I_1| + |I_2|}{2}$. Percent differential relays actuate when the ratio of $\frac{\text{operate current}}{\text{restraint current}}$ exceeds a certain percentage. The operating characteristic of the percentage differential element is a straight line with a slope of $\frac{\text{operate current}}{\text{restraint current}}$. These relays offer greater sensitivity to low-level transformer faults and minimize the likelihood of inadvertent trips during heavy through-faults. Microprocessor relays offer the ability to implement multiple slopes in a single

characteristic. The use of multiple slopes permits a very sensitive setting (small slope) for low current magnitudes and a less sensitive setting (higher slope) in the high current region where CT saturation is likely.



Key Technical Point

Microprocessor relays offer the ability to implement multiple slopes in a single characteristic.

Unlike an electromechanical relay, a numerical relay does not require a complicated current transformer (CT) scheme to match the measured currents. Instead, the relay uses entered information about the protected equipment and the current transformers to calculate the matched currents from the measured currents. This permits a standard CT secondary connection to be adopted, assigning the relay the task of calculating the necessary phase shift adjustments.



Key O&M Cost Point

Unlike an electromechanical relay, a numerical relay does not require a complicated current transformer (CT) scheme to match the measured currents. Instead, the relay uses entered information about the protected equipment and the current transformers to calculate the matched currents from the measured currents. This permits a standard CT secondary connection to be adopted, assigning the relay the task of calculating the necessary phase shift adjustments.

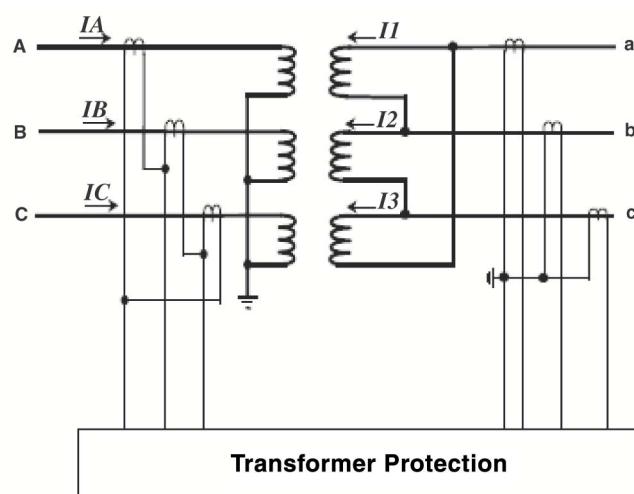


Figure 4-18
Classic Phase Shift Correction

To make the calculation, the relay must know the following information about the current transformers and how they are wired:

- The nominal secondary current rating of the CTs
- The nominal primary current rating of each CT set
- The orientation of the CTs relative to the protected transformer
- The choices for how to process the zero-sequence current
- The expected use of the ground-current inputs

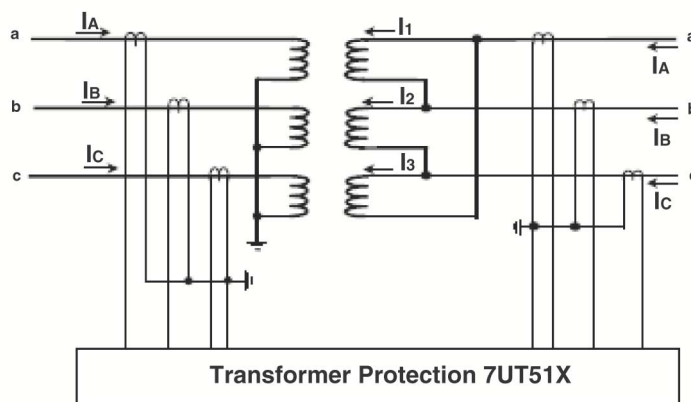


Figure 4-19
Standard CT Connection With Numeric Differential Relay Internal Phase Shift Correction

During energization, transformers draw a substantial magnetizing in-rush current. This presents a problem when differential protection is applied because the in-rush is seen as an internal transformer fault. To overcome this problem, microprocessor differential relays filter and measure harmonic content in the in-rush current to restrain or desensitize the differential units. Transformer currents exhibit a pronounced second harmonic when energized, but negligible second harmonics during an internal fault.

In some cases, sufficient second harmonic content may not be available to reliably restrain tripping when the transformer is energized. In this case, several options are available. Other odd harmonics are present during in-rush but are negligible during internal faults, although they are lower magnitude than the second harmonic. In cases where the quantity of second harmonics is questionable, third or fifth harmonics may optionally be included in the harmonic restraint characteristic of the relay. Another option is cross-blocking, where any phase that senses sufficient harmonic content is used to block all phases. In this manner, undesirable trips are avoided during energization of the transformer. On smaller distribution transformers, the in-rush current may not be severe enough to require harmonic restraint. In these cases, percent differential protection is adequate.

Numeric relays provide the ability to create innovative algorithms that change the nature of relaying. One example is the addition of algorithms that detect CT saturation for through-faults and prevent tripping.

Saturation of the current transformers caused by high-fault currents and/or long system-time constants are not critical for internal faults (fault in the protected zone) because the measured value deformation is found to the same extent in the differential current as in the restraint current.

During an external fault that produces a high through-fault current causing current transformer saturation, a considerable differential current can be simulated (especially when the degree of saturation is different at the two sides). If the quantities I_{Diff}/I_{Rest} result in an operating point that lies in the trip area of the operating characteristic of Figure 4-20, an undesired trip would result.

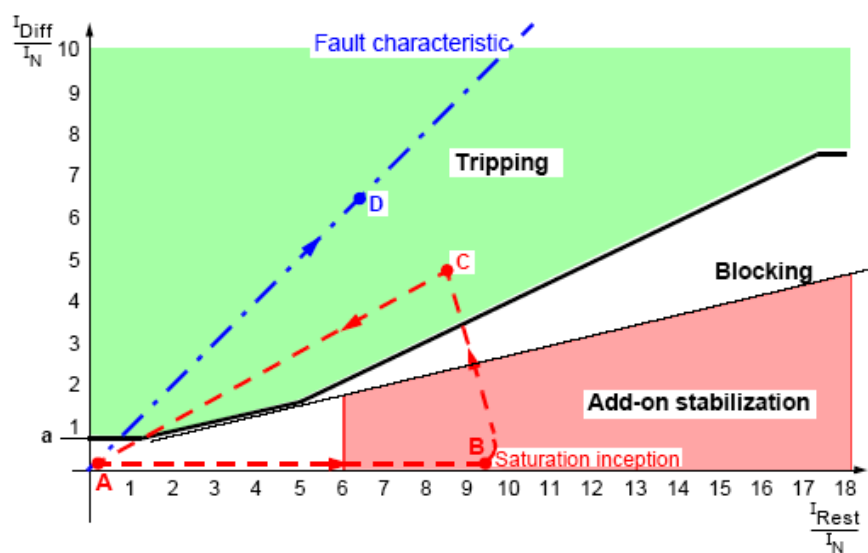


Figure 4-20
Through-Fault CT Saturation Detection – Add-On Restraint Characteristic

The saturation indication algorithm detects impending through-fault saturation and initiates add-on restraint measures. The saturation indicator considers the dynamic behavior of the differential and restraint quantity. The dashed line in Figure 4-20 shows an example of the shape of the instantaneous quantities during a through-fault current with current transformer saturation at one side.

Immediately after fault inception (A), the fault currents increase severely, producing a high-restraint quantity (twice the load current). At the instant of CT saturation (B) a differential quantity is produced and the restraint quantity is reduced. As a result, the operating point I_{Diff}/I_{Rest} may move into the tripping area (C). The through-fault saturation detection algorithm prevents operation.

For an internal fault, the operating point moves immediately along the fault characteristic (D). The through-fault saturation detection algorithm senses that the ratio of operate current/restraint current is too high to be a through-fault and allows an immediate differential trip.

4.20.1.2 Generator and Unit Protection

High-speed differential relays are used to provide generator protection against three-phase and phase-to-phase faults in the generator stator windings. Percent differential relays are used for generator protection for the same reason that they are used on transformers—they provide good sensitivity at light loads and are relatively immune to undesired trips during heavy external overloads. A fault in the stator windings can produce high and very destructive fault currents. Thus, the objective of differential protection is to remove the equipment from service as fast as possible.

Large generating plants are most often arranged with the generator and main transformer connected to the power system grid as a unit. When configured in this manner, the generator is said to be unit-connected. For unit-connected generators, the transformer differential relays are configured to include the generator within their zone of protection because the generator must be tripped on a main transformer fault. This setup provides backup protection against generator stator faults.

4.20.1.3 Motor Protection

Differential relays are employed when quick and accurate protection against faults is desired. Unlike conventional overcurrent relays, differential relays provide sensitive fault current detection and are not prone to false tripping during motor starting or external faults. Because of the added expense relative to conventional overcurrent protection, this type of protection is usually reserved for large, expensive motors.

4.20.1.4 Bus Protection

Various types of differential protection schemes are used for phase and ground-fault protection of buses. Bus differential protection is generally reserved for substation and switchyard buses. It is not frequently used for protection of in-plant distribution switchgear below 750 MVA.

4.20.2 Principles of Operation

A microprocessor percentage differential relay measures the amount of current entering and leaving its zone of protection. Figure 4-17 illustrates the concept of how a differential relay works. The CTs are connected to the relay and the relay calculates the necessary adjustments in magnitude and angle such that the calculated operate current will be zero (or near zero) if the currents are balanced (current entering the zone is equal to current leaving the zone). However, if a fault occurs within the zone, the measured currents are adjusted by the microprocessor for CT connection and tap, and the resulting calculation will produce a differential current. If the ratio of the calculated differential current to calculated restraining current is above the relay's slope curve, the relay initiates a protective action. Therefore, the relay's slope curve is a representation of the ratio of operate current to restraint current that will cause the relay to actuate.

Microprocessor relays permit multiple slopes to be combined into a single relay. The use of multiple slopes allows a more sensitive slope setting when the currents are low and a higher slope when high currents are likely to cause CT saturation. Figure 4-21 shows a typical percent differential characteristic with multiple slopes.

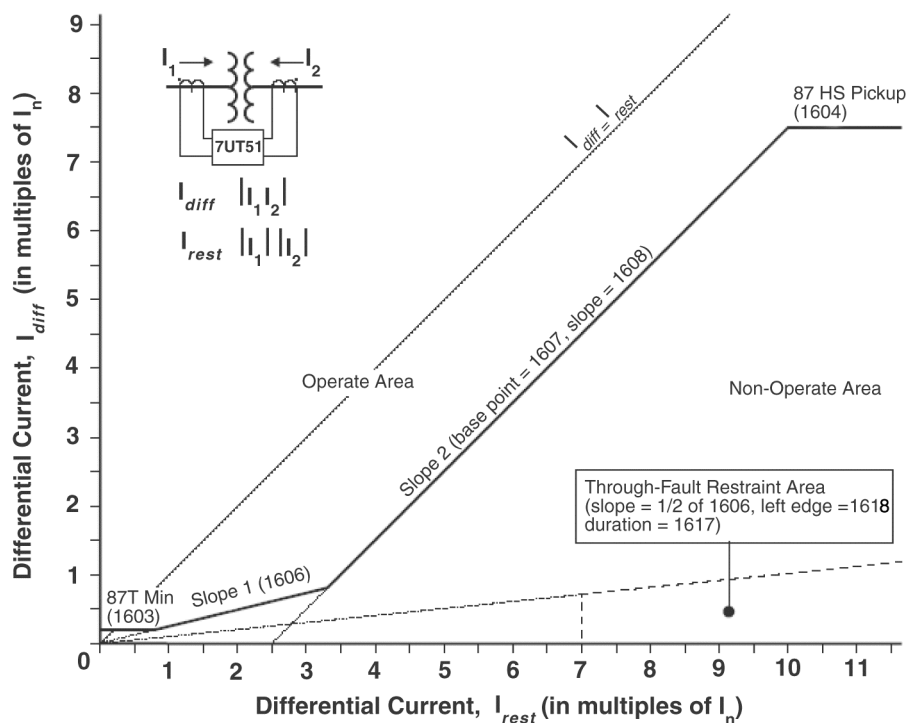


Figure 4-21
Modern Percent Differential Operating Characteristic With Multiple Slopes



Key Technical Point

Microprocessor relays permit multiple slopes to be combined into a single relay. The use of multiple slopes allows a more sensitive slope setting when the currents are low and a higher slope when high currents are likely to cause CT saturation.

The microprocessor allows innovative algorithms to be implemented that would not be possible with electromechanical relays. For example, an algorithm exists that allows sensitive slope settings even when underperforming CTs are likely to saturate during heavy through-faults. The algorithm makes a valid differential decision at fault inception in the time period before the CTs enter into saturation. In the case of a through-fault, the differential element is restrained for a predetermined length of time.

If a winding of the protected transformer has any connection to ground (as is usually the case for a wye-winding), there is likely to exist a zero-sequence current in the winding. Any zero-sequence current will by itself cause a differential current for one or more of the phases. Using the measured phase currents, the relay can calculate the expected zero-sequence current for each winding and mathematically eliminate it when calculating the matched currents for the differential protection. However, if the measured ground current(s) are available, the relay can also use it when calculating the matched currents—resulting in more sensitive differential protection.

Microprocessor differential relays also contain an unrestrained unit that will operate for fault currents large enough to preclude any possibility of a remote fault.

4.21 Current Differential Protection (87L)

4.21.1 Applications

The numeric differential protection functions as a selective short-circuit protection for overhead lines and cables with single and multi-ended feeds in transmission systems. Dealing with the system neutral is irrelevant because measuring data are compared separately for every phase. The term to describe this is phase-segregated.

High sensitivity and the in-rush current stabilization allow for the application of the current differential relay even in applications where a power transformer is located within the protected zone. The numeric relays can accommodate all types of power transformer connections including transformers with isolated or grounded neutrals.

A major advantage of the differential protection function is the ability to implement instantaneous tripping for a short circuit at any point in the entire protected zone. The current transformers limit the protected zone at the ends towards the line. This rigid limit is the reason why the differential protection scheme shows such an ideal selectivity.

The differential protection system requires a protective device as well as a set of current transformers at either end of the protected zone. Voltage transformers are not required. They can, however, be connected for the purpose of detecting and indicating measured values (voltages, power, and power factor). The devices located at the ends of the protected zone exchange measured information via interfaces using assigned communication links (usually fiber-optic cables) or a communication network. Two devices can be used for an object with two ends to be protected (that is, cables, overhead lines or both, with or without a unit-connected transformer). Employing certain types of relays, equipment having three (three-end lines) or more ends can be protected, whether or not unit-connected transformers are in use. Up to six ends can be protected, which means that smaller bus bar arrangements can also be protected.

**Key Human Performance Point**

The differential protection system requires a protective device as well as a set of current transformers at either end of the protected zone. The devices located at the ends of the protected zone exchange measured information via interfaces using assigned communication links (usually fiber-optic cables) or a communication network.

An error-free data transfer is the prerequisite for the proper operation of the protective system. Therefore, the accuracy of the data transfer is continuously monitored internally.

**Key Technical Point**

An error-free data transfer is the prerequisite for the proper operation of the protective system. Therefore, the accuracy of the data transfer is continuously monitored internally.

Recognition of short circuits in the protection zone (even weak-current or high-resistance shorting) is the basic function of the device. Also, complex multiphase faults are precisely detected because the measured values are evaluated phase-segregated. The protection system is stabilized against in-rush currents of power transformers. When switching onto a fault at any point of a line, an instantaneous trip signal can be emitted.

With more than two devices, the protection data communication can be built up as a ring. A ring provides a redundant communication pathway that enables continued operation in the event that one communication line fails. The devices will automatically find the remaining healthy communication lines. But even with two ends, communication lines can be doubled to create redundancies.

In the event of a total communication failure, the devices can be programmed to automatically switch to emergency operation using an integrated time overcurrent protection until communication is restored. This time overcurrent protection has three definite-time overcurrent stages and one inverse-time stage. A series of characteristics according to various standards is available for the inverse-time stage. Alternatively, the time overcurrent protection can be used as a backup time overcurrent protection (that is, it operates independent of and parallel to the differential protection at either end).

The communication link can be used for transmitting additional information. Apart from measured values, binary commands or other information can be transmitted (optionally). Depending on the relay type, the short-circuit protection functions can also trip individual phases (single-pole). They may operate in cooperation with an integrated automatic reclosure with which single-pole, three-pole, or single-pole and three-pole rapid automatic reclosure (as well as multishot automatic reclosure) are possible on overhead lines. It is possible to connect an external automatic reclosure device as well as double protection with one or two automatic reclosure functions. Apart from the short-circuit protection functions mentioned, a thermal

overload protection has been integrated that protects cables and power transformers from heating due to overload. Optional circuit breaker failure protection provides rapid backup fault clearance instruction to the adjacent circuit breakers in case the local breaker fails to respond.

Pilot wire differential relays are also used to protect short- and medium-length transmission and distribution lines. Conventional differential protection is not practical for transmission or distribution line-fault protection because of the distances required to bring CT and circuit breaker leads together.

Pilot wire differential protection may be employed at generating stations between the unit step-up transformer and the station switchyard if they are separated by a significant distance (typically greater than 2000 feet).

4.21.2 Principles of Operation

ANSI function 87L (current differential protective relay) is defined as a device that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electrical quantities.

The basic principle of the differential protection assumes that all currents flowing into a healthy protected section adds up to zero. If the current transformer sets at the line ends have different transformation errors in the overcurrent range, the sum of the secondary currents can reach considerable levels due to the saturation of the current transformers when a high-fault current flows through the line. This level of current may be interpreted as an internal fault. The features included in some relays to prevent errors in case of current transformer saturation can be successfully applied if the protection knows the response characteristic of the current transformers. To accomplish this, the characteristic data of the current transformers and of their secondary circuits are programmed into the relay. The rated accuracy limit factor (n) of the current transformers and the rated power (PN) are usually stated on the rating plate of the current transformers. The information stated refers to reference conditions (rated current, rated burden). With this information entered into the relay, it can compensate for current transformer saturation.

4.21.3 Pilot Wire Relays (87L)

Pilot wire relays also operate on the differential principle. Identical relays are installed at each end of the protected line. The relays are connected to each other via a pilot wire. The pilot wire serves as a means of information exchange between the two relays. It allows the current entering the zone to be compared to current leaving the zone at both relays. A fault within the zone of protection will be detected by both relays. Pilot wire protection allows for rapid isolation at both ends of a faulted line. As with all differential schemes, immunity against undesired trips during through-faults is high.

5

PROTECTION SYSTEM DESIGN

System protection has often been compared to insurance. As long as everything works well, it provides no tangible benefit. However, if a fault occurs, the system protection is responsible for minimizing the extent of the affected area, the amount of property damage, and the possibility of personnel injury. Just as with an insurance policy, the cost of protection should be compared to the cost and consequences of system failures.

Section 5 describes the design and application concepts used in protective relaying. By understanding the general design philosophy and approach of protective relaying, the importance of correctly performed maintenance can be more completely appreciated.



Key Human Performance Point

By understanding the general design philosophy and approach of protective relaying, the importance of correctly performed maintenance can be more completely appreciated.

5.1 Protection System Design Philosophy

5.1.1 Performance Objectives

The purpose of protective relaying is to initiate the prompt removal from service of any component of a power system when it suffers a short circuit or operates abnormally in a manner that might interfere with the effective operation of the rest of the system. The ideal protective relay accomplishes the following objectives:

- Promptly removes faulted components from service with as little disruption as possible to the rest of the system
- Performs no action in response to anticipated system transients or tolerable (but abnormal) conditions

When a fault occurs within a system, the primary protective relays closest to the fault should act promptly to isolate the fault. Depending on the design and function, backup relays farther away from the fault may begin to operate but should not actually initiate any tripping functions as long as the primary relays function properly. If the primary relays fail to isolate the faulted condition, the backup relays should complete their operation to isolate the fault.

5.1.2 Ideal Relay Characteristics

Protective relays do not prevent abnormal occurrences or failures within the power system. Instead, protective relays respond to conditions indicative of a system or equipment problem. In other words, these relays do not anticipate problems, but they respond to problems when the abnormal condition has been recognized. This is largely true for electromechanical and static protective relays. Digital relays also react to a change in system conditions. Relays are intelligent and can make decisions based on the recorded historical data and the change taking place due to an abnormal condition. Therefore, it is possible for a digital relay to distinguish between a fuse-fail condition and an actual short circuit that would look identical for a 21 relay.



Key Technical Point

It is possible for a digital relay to distinguish between a fuse-fail condition and an actual short circuit that would look identical for a 21 relay.

In general, the ideal protective relay would have the following design characteristics:

- **Maximum reliability:** The relay will actuate only for equipment or system conditions indicative of a problem. Spurious relay actuation or actuation in response to normal or tolerable transient conditions will not occur.
- **Maximum speed:** The relay will detect equipment or system faults and perform its protective function as fast as possible while maintaining selectivity and security.
- **Selectivity:** Only the faulted equipment will be removed from service by the protective function—minimum system disruption occurs as a result of relay actuation.
- **Simplicity:** The relay protection scheme will be designed as simply as possible. It is extremely easy to over-design a protection scheme using multifunctional digital relays. Care must be taken not to have too much redundancy that could lead to unnecessary complexity of the overall system design.
- **Provide Information:** The digital relays must be able to provide the user with information regarding a fault or event. The relays have the capability to record events that include plant status, protective function tripping data, and analog data representing the currents and voltages connected to the relay. This is one of the main advantages of digital protective relays. The more accurate and accessible the information, the easier it is to analyze and make informed decisions to return a machine to service.
- **Low Cost:** The previously listed design characteristics will be achieved at the lowest possible cost. Digital multifunctional relays have drastically reduced the cost of a protection system compared to that of an electromechanical system. Cost is therefore not a real factor compared to the investment being protected. It is possible to completely protect a generator using two digital multifunctional relays that have more functionality and redundancy than an electromechanical system design. The key issue concerns the most cost-effective method to upgrade to this type of protection.

Additional information on some of these characteristics as well as other factors are presented in the following subsections.

**Key O&M Cost Point**

The digital relays must be able to provide the user with information regarding a fault or event. The more accurate and accessible the information, the easier it is to analyze and make informed decisions to return a machine to service.

5.1.2.1 Reliability

Protective relay reliability is described in the following two ways:

- The relay must operate correctly in response to a system problem (dependability)
- The relay must not operate incorrectly during normal system operation (security)

Dependability is defined as the degree of certainty that a relay or relay system will operate correctly. Security is defined as the degree of certainty that a relay or relay system will not operate inadvertently. In more direct terms, dependability is a measure of the ability of the protective relay to perform correctly when required. Security is its ability to avoid unnecessary operation during normal system conditions or in response to system faults outside its zone of protection. Increasing relay dependability tends to reduce relay security, and increasing relay security tends to decrease relay dependability. Balancing these two system needs while also anticipating the many possible unusual system configurations requires considerable expertise.

Digital relays provide the platform to maximize dependability and security. The reason for this is quite simple. Digital relays can make informed decisions based on past-recorded or buffered historic data. It is quite common to build logic into digital relays that will slow the relay down under certain conditions and speed it up under other conditions, thereby maximizing security and dependability in a way that was not possible with electromechanical relays.

**Key Technical Point**

Digital relays provide the platform to maximize dependability and security.

Dependability is relatively easy to verify. Relay testing can determine that the relay responds correctly when defined set points are exceeded. Digital relays, however, would need the tester to apply pre-fault conditions before applying the actual simulated fault. Thus if the system fault conditions for which the relay must actuate are understood, the reliability of the relay to perform its design function can be verified by testing.

Security can be more difficult to verify for a relay. To evaluate a relay's performance in the area of security, each fault outside the protected zone that the relay detects must be considered. This can be difficult in complex transmission and distribution networks when switching and load-flow conditions change the numerous parameters that impact external fault scenarios. It can be

difficult to anticipate of the possible system configurations that may exist during normal operation for which the relay must not actuate. Fortunately, nuclear plants tend to operate in a manner that is well-defined and somewhat fixed, making relay security easier to measure.

5.1.2.2 Selectivity

The fact that the relay is selective means that only the faulted equipment will be removed from service by the protective device. Minimum system disruption occurs as a result of relay actuation. Protective relays used in power plants are designed so that the relay closest to the fault responds first to isolate the fault. The relay closest to the fault is primarily responsible for removing the fault as soon as possible, thereby limiting the loss of power. If the primary protection fails, backup protection may then respond to clear the fault. This principle of operation is termed selectivity and is a fundamental design requirement to minimize the amount of the system deenergized in response to a faulted condition. In this manner, zones of protection may be allowed to overlap.

An example of this is the application of protective schemes such as reverse interlocking for bus protection using the instantaneous overcurrent relay. In this application, the bus relay receives inputs from instantaneous overcurrents associated with each feeder relay. Operation of any feeder relay blocks the operation of the bus relay's primary protection to prevent an overtrip for faults outside the bus zone of protection. This example defines how a selective scheme allows isolation of the faulted feeder without affecting the rest of the distribution circuits. The coordination study defines the setting threshold and time coordination of the relays.

5.1.2.3 Simplicity

The protection system design should not be more complex than is necessary to implement the protection objectives for the system. Each added component adds to the system cost as well as ongoing maintenance costs. Furthermore, each added component may detract from the overall system dependability and security. The system design should be optimized to balance all goals.

The physical behavior of electromechanical relays simulated in a digital signal microprocessor is called an algorithm. The advantage of numerical-based relays is that a microprocessor is a multitasking device. The relay can be a multifunctional relay and replace the multiple single-phase single-function components of electromechanical relays. The relay can monitor itself, utilize self diagnostics, and alarm when it is not providing protection. This simple feature is one of the most valued aspects of the modern numerical protection relays.



Key Human Performance Point

The physical behavior of electromechanical relays simulated in a digital signal microprocessor is called an algorithm. The relay can monitor itself, utilize self diagnostics, and alarm when it is not providing protection.

5.1.2.4 Redundancy

The quantity and arrangement of protective relays can also impact dependability. In critical applications and safety-related schemes, the excellent and proven reliability record of numeric relays can be further improved by employing redundant relays. A well-designed redundant relay scheme can reduce exposure to single point failures and further improve reliability in the event of single relay failure. Exposure to single point failures can be further reduced by employing redundant relays using different measurement algorithms and power supply designs.

For example, if two sets of redundant numeric relays are arranged with parallel trip outputs, overall reliability is improved in the event of a single relay's failure to operate for a fault. This arrangement should be used if the predominant failure mode of the relays is a failure to trip. Placing two redundant relay trip outputs in series can increase reliability if the relay exhibits a tendency to issue undesired trips in the absence of a fault in the protected zone.

Choosing between parallel and series trip outputs for redundant relays requires that the failure mode of the relay be anticipated with a relatively high degree of certainty. Using parallel trip contacts with a relay that tends to issue undesired trips doubles the exposure to a false operation. Likewise, employing series trip contacts with a relay model that exhibits a tendency to fail to operate for an internal fault increases the exposure to misoperation.

Numeric relays have an excellent track record and failures are rare. The high reliability of numeric relays may make it impossible to obtain meaningful failure mode data and tendencies. In this case, it is still possible to use redundant relays to improve reliability and to reduce single-point failure exposure by using a two-out-of-three voting scheme. The benefits of improving dependability through redundancy must be carefully considered due to a trade-off in increased cost.

5.2 Protection System Design Approach

5.2.1 Zones of Protection

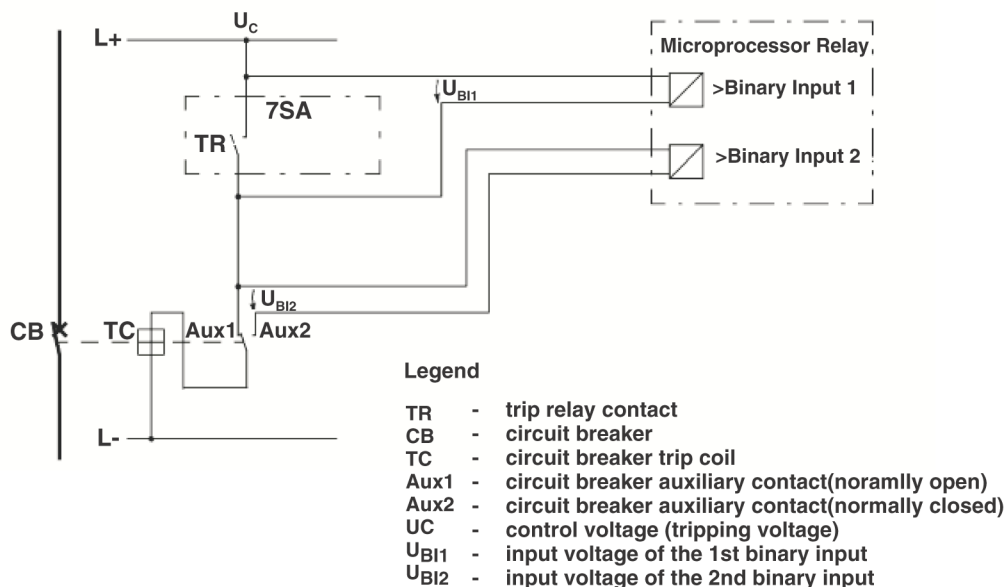
The general design approach of protective relaying is to divide the electrical power system into zones that can each be protected with the minimum possible disruption to the rest of the system. The concept of protective zones applies to protective relaying regardless of whether the system to be protected is a major transmission and distribution system or a single power plant. In either case, a fault or intolerable transient should be disconnected from the system with as little impact as possible to the unaffected portion of the system.

A typical power system is separated into the following zones:

- Generators
- Transformers
- Buses
- Transmission lines and cables
- Motors

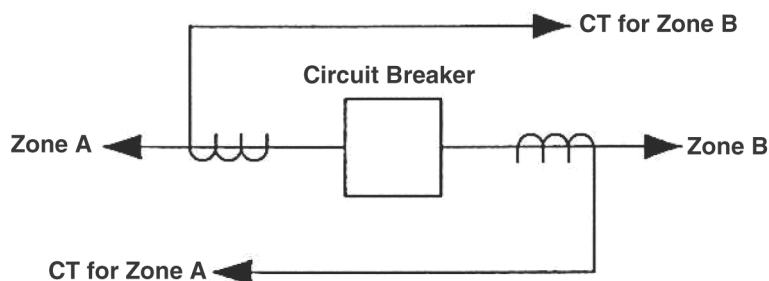
A portion of a power system identifying typical zones of protection is shown in Figure 5-1. The dashed lines indicate the zones of protection into which this simple power system has been divided. Each zone contains one or more power system components in addition to the circuit breakers located at the zone boundaries.

Zones of protection are defined around circuit breaker locations. A general design philosophy is that a fault within a given zone should cause the tripping of all circuit breakers at the zone boundary and no tripping of circuit breakers outside the faulted zone. It can be seen in Figure 5-1 that zones of protection are overlapped to avoid the possibility of any unprotected areas in the power system. However, the area of overlap is usually minimized as much as possible because a fault in the overlap region would result in the isolation of two zones. Figure 5-2 shows in detail the principle of overlapping protection around a circuit breaker.

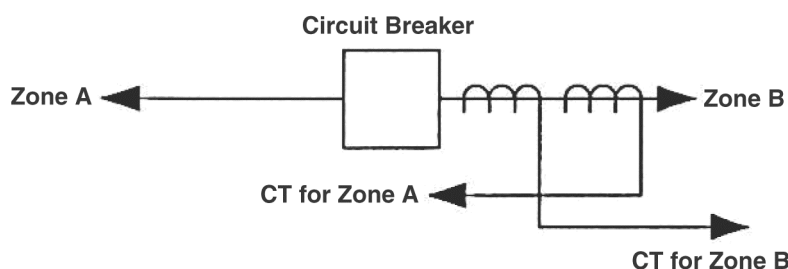


Note: The circuit breaker is shown in closed position

Figure 5-1
Overlapping Zones of Protection



a) Dead Tank Breaker and Breakers with Separate Current Transformers on Both Sides of Breakers



a) Live Tank and Breakers with Separate Current Transformers on One Side Only

Figure 5-2
Overlapping Protection Around a Circuit Breaker

5.2.2 Primary and Backup Protection

The zones-of-protection principle described in the previous section is an example of primary protection in which a faulted zone is isolated to remove the fault. Backup protection is the second line of defense and functions to clear the fault in the event that the primary protection fails to operate properly. Depending on the design and function, backup relays may begin to operate, but they should not actually initiate any tripping functions as long as the primary relays function properly. If the primary relays fail to isolate the faulted condition, the backup relays should complete their operation to isolate the fault. Digital relays can be applied in many different configurations.

Due to the multifunctionality of these relays, it is quite easy to design a system that has two systems providing almost complete redundancy as shown in Figure 5-1. It is possible to use relays from different manufacturers to improve security. It is further possible to design systems using voting schemes. For example, three relays can be used to make a trip decision. If any two relays agree, the trip will be issued. Although these schemes seem to be very secure, they could become extremely costly and complicated to design, build, test, and maintain.

Note that the failure of primary protection does not mean only that a protective relay failed. Primary protection may fail to isolate a fault due to a failure of any of the following devices:

- Protective relays
- Instrument transformers
- Tripping circuits
- Circuit breaker
- Tripping circuit voltage supply

Upon failure of the primary protection, the available backup protection acts to isolate the fault. The method used to distinguish whether or not the primary protection has failed is usually based on time—after a selected time delay during which the primary protection should have isolated the fault, the backup protection will complete its protective response. In a power plant, the actuation of backup relaying will often involve the isolation of multiple zones of protection. For example, an entire load center may be isolated after the backup protection actuates to isolate a motor fault.

In general, backup protection is applied mainly for short-circuit protection. Because short circuits are the most common form of power system failure, backup protection is of the greatest value for short-circuit relaying. A typical backup protection scheme is shown in Figure 5-2. For a ground fault on the generator, relay 2 should issue a trip to clear the fault. In the event that relay 2 fails to trip, relay 1 must operate to isolate the fault.

5.2.3 Power Plant Protection Design Criteria

5.2.3.1 Power Station Relay Standards

Industry standards are used to develop new relay designs. Numerical relay manufacturers use both ANSI/IEEE and IEC standards to test relay performance because relays are now marketed for worldwide applications.



Key Technical Point

Numerical relay manufacturers use both ANSI/IEEE and IEC standards to test relay performance.

Standards for power stations provide details for protection schemes and setting methods for common applications such as generator, motor, switchgear, and transformer protection.

Protection schemes specifically applied to generators and unit transformers addressed by industry standards include the following types of protection:

- Differential
- Stator ground
- Overvoltage
- Loss of synchronism (out-of-step)
- Field ground fault
- Rotor thermal
- Loss of excitation p
- Unbalanced current (negative-sequence)
- Vibration
- Anti-motoring (reverse power)
- Overspeed
- System backup
- Abnormal frequency
- Over-excitation

The more commonly referenced standards are listed in the Appendix C of this document.

5.2.3.2 Class 1E Nuclear Protection

IEEE standards generally refer to the safety classification of Class 1E as an essential element in preventing the significant release of radioactive material to the environment.

Safety system equipment in nuclear power stations is engineered to meet or exceed industry design standards. Design qualification and quality assurance programs relate to installation, maintenance, and generation production to ensure that the design is adequate and safe. Designs must focus on two primary areas:

- The equipment within the station must be capable of performing designated safety functions in post-design service environments
- In-service aging of the protection must not degrade the safety system equipment in such a way that it varies from the original design conditions to a point where it cannot perform the safety function.

Perhaps the greatest area of concern is common mode failure. Design qualification programs should give assurance that design and age-related failures do not exist so that adequate protection is maintained over time.

Nuclear protection must meet more stringent guidelines as compared to nonnuclear power system installations. Nuclear regulatory bulletins and guidelines are issued so that nuclear station protection engineers are aware of protection design requirements and relay operational information. Some of these documents are referenced in Appendices A and C.

5.3 System Interfaces

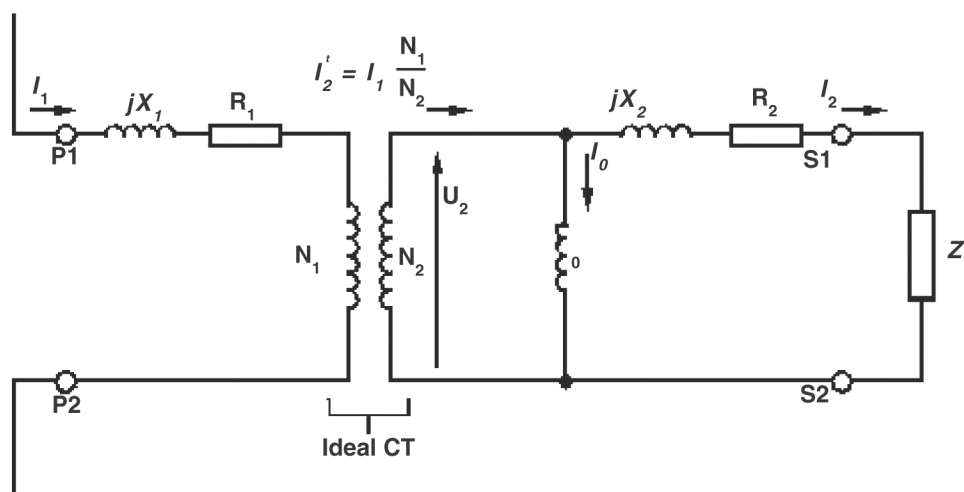
5.3.1 Instrument Transformers

Instrument transformers are used as the sensing devices for protective relays. Relays do not sense electrical system parameters directly—instrument transformers are used as intermediate sensing devices to reduce the sensed electrical quantities to lower levels to provide a safer work environment for personnel and to allow for a simpler and less expensive relay design.

Instrument transformer design and performance is an important part of relay design. Protective relays can be no more accurate than the instrument transformers that provide the input information. Instrument transformers operate on the same principles as ordinary transformers; however, they are specifically designed to duplicate the input waveform as closely and predictably as possible.

5.3.1.1 Current Transformers

Current transformers (CTs) are connected in series with the circuit whose current is to be measured as shown in Figure 5-3.



X_1 = Primary leakage reactance
 R_1 = Primary winding resistance
 X_2 = Secondary leakage reactance
 Z_0 = Magnetizing impedance
 R_2 = Secondary winding resistance
 Z_b = Secondary load

Note: Normally the leakage fluxes X_1 and X_2 can be neglected

Figure 5-3
Current Transformer Circuit Detail

CTs are intended to deliver a secondary current that is directly proportional to the primary current with as little distortion as possible. In most cases, the secondary output current is usually reduced to a level less than 5 amperes. Although there are CTs with 1 ampere or 10 ampere secondaries, the most common rating in the United States is 5 amperes.

CTs are rated for a certain turns-ratio of operation. For example, a CT with a turns-ratio of 500:5 reduces 500 amperes on the primary to 5 amperes on the secondary. A properly designed CT circuit yields a secondary current of 5 amperes or less at rated primary current. Although the CT secondary and the relay are not intended for continuous operation at higher than 5 amperes, they are designed to withstand greater values of current for short periods. For example, short-circuit currents may be 20 or more times the normal current in a power system.

During normal operation, the CT secondary winding induces a magnetic flux that opposes and nearly cancels the primary induced flux. As a result, the flux density is very low and the resulting voltage at the secondary terminals is also very low. Relays, meters, or other connected devices are constructed with only a few turns of relatively large wire—this low impedance effectively functions as a short circuit across the CT secondary. The secondary voltage of a CT remains at a low value as long as the secondary circuit remains closed. An open circuit on the secondary side of a CT that still has current flow on the primary side can result in a dangerously high secondary voltage. Opening the secondary removes the opposing secondary flux, thus allowing the primary flux to generate a very high voltage at the secondary terminals. Equipment can be damaged and

personnel can be injured by electrical arcing due to an open-circuited CT. When the primary side is carrying any current, great care must be taken to ensure that the secondary circuit remains closed at all times.

The CT's ability to produce a secondary current proportional to its primary current is limited by the highest secondary voltage that it can produce without saturation. Beyond a certain level of excitation (actual values are readily available from the manufacturer), the CT is said to enter saturation. When saturated, most of the primary current maintains the core flux, and the shape of both the exciting and secondary currents departs from the normal sine wave. The secondary voltage and current then collapse to zero where they remain until the next primary current zero is reached. The process is repeated each half-cycle and results in a distorted secondary waveform. Saturation of a CT can prevent a protective relay from operating properly. For this reason, a CT must be carefully sized so that it will perform properly for the maximum expected fault current. Low-ratio CTs (for example, 50:5 or 75:5) are particularly susceptible to saturation during fault conditions.



Key Human Performance Point

Saturation of a CT can prevent a protective relay from operating properly. For this reason, a CT must be carefully sized so that it will perform properly for the maximum expected fault current.

The following problems may exist if a CT is allowed to saturate:

- False tripping - Differential relays used for transformer protection may respond to a through-fault condition. Numerical relays, however, pose far less burden (0.5 VA) on current transformers. Numerical relays are capable of detecting CT saturation and blocking the relay from tripping, minimizing the effect of false tripping.
- Delayed tripping - A distorted secondary reproduction of the primary current can delay relay time response. This delay in tripping may result in deenergizing a larger portion of the system due to loss of relay coordination caused by the CT saturation.
- Failure to trip - Failure to trip may occur if the CT secondary current is very low or extremely distorted. Backup relays must then respond to clear the fault. Digital relays, however, have the added advantage that they can detect these conditions and still deliver a trip because the relay is not dependent on the power that must be supplied by the CT to trip.

5.3.1.2 Voltage Transformers

Voltage transformers (VTs)—formerly called potential transformers (PTs)—are connected in parallel with the circuit whose voltage is to be measured as shown in Figure 5-3

VTs provide a secondary output voltage proportional to the primary voltage. For the typical primary voltages used in nuclear plants, the VT turns ratio will usually be designed to provide an output voltage of 120 V. The ideal VT delivers a secondary voltage directly proportional to the primary voltage with as little phase angle difference as possible between the primary and secondary voltages.

VTs are generally far more accurate than CTs. Also, VTs do not experience saturation problems that may occur with CTs. CTs may have the primary current increase by 20 times or more during a fault, but VTs will never have the primary voltage increase as dramatically.

5.3.2 DC Tripping Circuits

ANSI/IEEE C37.90-1989 defines the criteria for DC power supplies and auxiliary circuit DC voltage maximum design ratings. Table 5-3 lists these ratings as provided by ANSI/IEEE C37.90. Numerical relays applied at these voltages are designed to be capable of operating successfully over a range from 80% of the rated voltage.

Table 5-1
ANSI/IEEE C37.90-1989 Table 3 – Maximum Design Voltage for DC Control Power

Maximum Design Voltage for DC Control Power	
Rated Volts	Maximum Design Volts
24	28
48	56
125	140
250	280

Older relays actuated a trip contact in the breaker tripping circuit to energize the trip coil. Trip circuits in a numerical relay are now wired to binary outputs, which are connected in a similar fashion to energize the trip coil. These binary outputs have the capability of being set in a “latched” or “unlatched” position after operation. Typically, the tripping circuit binary output is set as an unlatching type. When connected to the circuit breaker trip coil or in circuits where “lock-out” functionality is required, a latching type may be used.

Numerical relays can have the capability of being connected to a variety of power supply voltages. Options are available that include multirange supplies or universal power supplies. Multirange power supplies may require an internal jumper to be set for a specific supply voltage.

Because local and remote control can be integrated in numerical relays, tripping can be initiated using trip control switches located on the front panel of the relay to actuate the trip circuit or via the system interface protocol.



Key O&M Cost Point

Because local and remote control can be integrated in numerical relays, tripping can be initiated using trip control switches located on the front panel of the relay to actuate the trip circuit or via the system interface protocol.

Many numerical relays include an integrated trip circuit monitor. Depending on the number of available binary inputs, monitoring with one or two binary inputs can be selected to monitor the tripping circuit. When using two binary inputs, malfunctions in the trip circuit can be detected under all circuit breaker conditions. When only one binary input is used, malfunctions in the circuit breaker itself cannot be detected—only the trip coil circuit. Section 13.1 discusses trip coil monitoring in detail.

**Key Technical Point**

When using two binary inputs, malfunctions in the trip circuit can be detected under all circuit breaker conditions.

Electromechanical relays used a seal-in target to flag the operator when tripping had occurred. Numerical relays use light emitting diodes to link binary trip outputs to an LED location for signaling a trip. The trip operation can also be signaled back to the main control center via the system interface protocol.

5.3.3 Communication Equipment

Modern numerical relays provide flexible designs as they relate to protection and they allow the user to connect devices to a variety of communication platforms.

Numerical relays are typically designed with the communication functionality isolated from the protection features. Various communication options are now offered with numerical relays. In the past, electromechanical and solid-state relays had limited communication capabilities.

Numerical relay communication to the outside world can include relay to personal computer, relay, power-line carrier, SCADA interface, and satellite communications. Communication interfaces are becoming increasingly important for the efficient and economic operation of generating stations and networks.

**Key Human Performance Point**

Numerical relay communication to the outside world can include relay to personal computer, relay, power-line carrier, SCADA interface, and satellite communications. Communication interfaces are becoming increasingly important for the efficient and economic operation of generating stations and networks.

5.3.3.1 Power-Line Carrier

With the increased use of fiber, power-line carrier communication is considered less frequently in modern relay communication designs. However, when protection schemes are updated, they must still interface with remote power system schemes that may include power-line carrier. This is easily handled with modern relays.

Power-line carrier communication for line distance protection and direct transfer trip is found in generating switchyards on transmission lines that feed out of the generating facility that is used in conjunction with line distance protection. This form of communication is connected to remote line terminals using the primary conductor of the power line. The secondary communication equipment is coupled to the primary by means of coupling capacitor potential devices, filters, and tuning equipment.

This form of communication allows transmission line relay terminals to pass signals between stations to block or initiate tripping depending on the application requirements.

5.3.3.2 SCADA

Most modern day substations and generating facilities use some form of SCADA (supervisory control and data acquisition) to allow operators or operating centers to remotely monitor and control equipment. SCADA originates from the control center in software form and is used for process controlling. SCADA works by gathering data in real time from remote locations in order to control equipment and conditions. SCADA is used in power plants as well as in oil and gas refining, telecommunications, transportation, and water and waste control.

From the control center, SCADA computers are connected to remote locations using various forms of communication equipment and protocols (that is, DNP, Modbus, or Profibus).

SCADA systems include hardware and software components. The hardware gathers and feeds data into a computer that has the SCADA software installed. The computer then processes and presents the data in a timely manner. SCADA also records and logs all events into a file stored on a hard disk, which can be sent to a printer for analysis or reporting. One significant advantage of having a SCADA versus a remote control system is the ability to expedite abnormal system alarm conditions to operators for remote equipment problems or misoperation.

5.3.3.3 IRIG B

Many numerical relays now have the option to provide time-of-day information in synchronous form for data correlation with time. This feature is important when evaluating system-wide transients. Parallel and serial formatted time codes are used to efficiently interface the timing system (time-of-day source) to the user system. Parallel time codes are defined in IRIG Standard 205-87. This standard defines the characteristics of six serial time codes.

**Key Technical Point**

Many numerical relays now have the option to provide time-of-day information in synchronous form for data correlation with time.

The family of rate-scaled serial time code formats is alphabetically designated A, B, D, E, G, and H. In the relay industry, IRIG B format is the standard format. IRIG B is a 74-bit time code that contains 30 bits of BCD time-of-year information in days, hours, minutes, and seconds; 17 bits of seconds-of-day; and 27 bits for control functions with a 10 msec resolution.

With the IRIG communication capability, multiple relays can be time-synchronized by using an IRIG B clock reference. This allows for comparison between multiple relay events and fault recordings without introducing timing errors.

**Key O&M Cost Point**

With the IRIG communication capability, multiple relays can be time-synchronized by using an IRIG B clock reference. This allows for comparison between multiple relay events and fault recordings without introducing timing errors.

5.4 Selective Tripping

5.4.1 Inverse-Time Characteristics

The protective device coordination in a radial feeder or for any distribution feeder is important. The coordination of protection devices is necessary to maintain selectivity, (that is, to remove the portion of the power system that is experiencing the fault). The inverse-time current curve provides coordination at the same time that it offers the speed and accuracy needed to clear the correct fault quickly. By the nature of the design, the inverse-time curves utilize the magnitude of the current to decide the tripping time, unlike the instantaneous relays with definite time.

The name of the inverse-time curve is self-explanatory. The higher the magnitude of the fault or the load current, the less time is required for the relay to operate. This provides quick removal of the faulted portion from the power system. Under normal load condition or for a low-magnitude fault current, the relay allows enough time for other downstream devices to clear the fault. Because the microprocessor relay has to process the current mathematically to decide the time to trip, the relay can be equipped with different types of inverse curves.

The user at the time of the study decides the curve to be used. The relay simply actuates that curve equation and processes accordingly. IEEE has created standard inverse curves. The manufacturer of the microprocessor relay must comply with these curves. Depending on the time to trip for higher current or for lower current, different curves are available.

The following list includes a few of the many popular curves:

- Moderately inverse
- Inverse
- Normally inverse
- Very inverse
- Extremely inverse

Figure 5-4 depicts these curves with the equations set forth by IEEE.

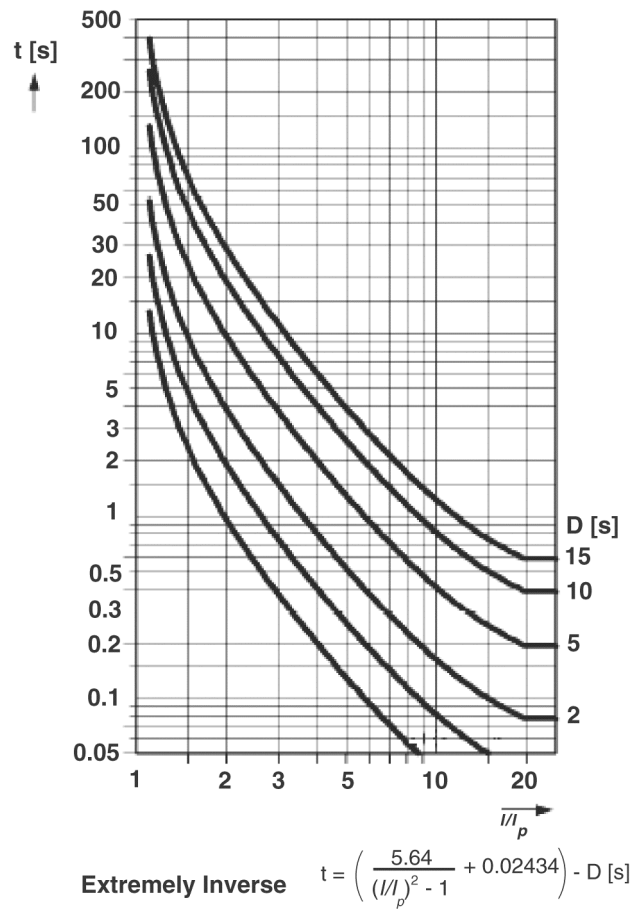


Figure 5-4
IEEE Inverse Time Characteristic Curves

5.4.2 Short-Circuit Study

In order to obtain complete coordination of the protective equipment applied, it may be necessary to obtain some or all of the following information on short-circuit currents for each node or bus:

- Maximum and minimum momentary (first cycle) short-circuit current
- Maximum and minimum interrupting duty short-circuit current
- Maximum and minimum ground-fault current

The momentary currents are used to determine the maximum and minimum currents to which instantaneous and direct-acting trip devices respond.

The maximum interrupting current is the value of the current at which the circuit protection coordination interval is established. The minimum interrupting current is needed to determine if the protection sensitivity of the circuit is adequate.

A short-circuit study and coordination study should be updated when the available short circuit of the source to a plant is increased.

5.4.3 Protective Device Coordination

The objective of a coordination study is to determine the characteristics, ratings, and settings of overcurrent protective devices to ensure that the minimum unfaulted load is interrupted when the protective devices isolate a fault or an overload anywhere in the system. At the same time, the devices and the settings selected should provide satisfactory protection against overloads on the equipment and should interrupt short-circuit currents as rapidly as possible.

The coordination study provides data useful for the selection of instrument transformer ratios, protective relay characteristics, and settings and fuse ratings. It also provides other information pertinent to the provision of optimum protection and selectivity in coordination of these devices.

When plotting coordination curves, a certain time interval must be maintained between curves of the various protective devices in order to ensure correct sequential operation of the devices. This interval is called the coordination time interval.

When coordinating inverse curves, the time interval is usually 0.3–0.4 sec. This interval is measured between relays in series at the instantaneous setting of the load side of the feeder relay or maximum short-circuit current, which can flow through both devices simultaneously.

A basic understanding of time-current characteristics is essential in any study. Initial planning and power system data are also essential for any coordination study.

The initial planning process should include the following activities:

- Develop a one-line diagram
- Determine the load flow
- Collect data
- Conduct a short-circuit study
- Determine time current coordination curves for all the devices in the system

6

NUMERICAL RELAY MAINTENANCE PRACTICES

6.1 Background Information

Because electromechanical relays had moving mechanical parts (such as contacts and targets), and electrical components (such as capacitors and coils), concerns existed that failures or relay setting drift could occur over time. This generated further concern that the reliability of the protection would be compromised. For this reason, frequent calibration and functional tests were implemented to monitor the performance and to correct problems in order to maintain reliable relay operation. These tests included visual inspections, cleaning of contacts and moving parts, setting calibration to check for proper pickup, and an overall operational test of the scheme that included operating the associated primary equipment connected to the protection.

Maintenance programs have been in existence for years. Programs have evolved over time as relay design and technology have changed. Maintenance intervals have typically been set by the users and were developed as a result of the maintenance philosophies and relay performance history. No standard exists that defines maintenance intervals for various types of relays and their applications. There has been an increased emphasis placed on network reliability in recent years and, due to competition between companies, greater emphasis has been placed on maintaining and increasing their customer base. This has driven companies to place more focus on their maintenance programs. Federal and regional guidelines and regulations may eventually dictate specific maintenance requirements locally or even industry-wide.

As customers have added numerical relays, maintenance intervals have been extended due to the nature of the equipment design. Moving parts, contacts, coils, and drift problems have been virtually eliminated. Currently, the focus has moved from calibration testing to functional or scheme testing. The numerical relay has proven to be a reliable and accurate device; therefore, less maintenance is required.



Key O&M Cost Point

As customers have added numerical relays, maintenance intervals have been extended due to the nature of the equipment design. Moving parts, contacts, coils, and drift problems have been virtually eliminated. The numerical relay has proven to be a reliable and accurate device; therefore, less maintenance is required.

Most manufacturers state that no maintenance is required on their numerical relays. However, this does not eliminate the need to check the overall operation and to verify that the primary

equipment operates reliably. A structured and consistent relay maintenance program should be set up for numerical relay schemes so that reliable protection operation is maintained.

**Key Human Performance Point**

Most manufacturers state that no maintenance is required on their numerical relays. However, this does not eliminate the need to check the overall operation and to verify that the primary equipment operates reliably.

6.2 Classification of Maintenance

Maintenance and testing of protective relays can be logically divided into four categories—acceptance testing, installation checks, preventive (or periodic) maintenance, and post-repair or maintenance checks. Each category represents an event or circumstance that warrants some sort of maintenance action. These maintenance categories for protective relays are discussed in the following subsections.

6.2.1 Acceptance Testing

Acceptance testing is associated with the design and manufacture of products. Manufacturers or certifying authorities conduct these tests to validate new product designs and to ensure that production units meet design and manufacturing requirements.

End users often choose to perform acceptance tests on newly received units to verify that performance characteristics and factory settings are as specified. A receipt inspection is typically done to ensure that no shipping damage has occurred.

6.2.2 Installation Checks

Installation checks are conducted when a protective relay is initially placed in service. Installation checks include calibration, mechanical inspections, and electrical tests. These checks are conducted to ensure that the proper settings and configuration parameters have been downloaded to the relay, that it is installed correctly, and that it is otherwise fully capable of performing its intended function.

6.2.3 Preventive (or Periodic) Maintenance

Preventive maintenance is performed on a scheduled basis for the following reasons:

- To detect and correct actual or impending problems
- To verify that relay performance is within acceptable operating limits
- To reduce the likelihood of future failure or degraded performance by ensuring that the relay is in good working order

Preventive maintenance may include tests, checks, inspections, measurements, replacements, refurbishment, firmware updates, and similar activities.

6.2.4 Post-Repair or Replacement Checks

Post-repair or replacement checks are conducted subsequent to repairing a relay or replacing a relay or components. These checks are performed to verify that the repairs were successful, that the replacement components were installed properly, and to otherwise ensure that the relay is operating satisfactorily after corrective maintenance. Post-repair checks are identical to the installation checks that will be normally done as described in Section 6.2.2

6.3 Overview of Protective Relay Checks, Inspections, and Tests

The four major categories of relay maintenance discussed in Section 6.2 establish a program-level structure for conducting protective relay maintenance. The next logical question concerns the specific checks, inspections, and tests that should be performed within each category. The following subsections define specific maintenance items (that is, types of checks, inspections, and tests) applicable to protective relay maintenance. Section 8 ties the specific maintenance items to the major maintenance categories.

Numeric relays have revolutionized all aspects of protection and control. Testing is no exception. There is room for much innovation in developing test strategies and there is not likely to be a consensus for some time to come. Practices will vary from utility to utility.



Key Human Performance Point

Numeric relays have revolutionized all aspects of protection and control. Testing is no exception. There is room for much innovation in developing test strategies and there is not likely to be a consensus for some time to come. Practices will vary from utility to utility.

6.3.1 Visual Inspection and Cleaning

A visual inspection is a thorough check of a relay to identify conspicuous signs of unusual degradation or, in the case of new relays, shipping damage. A visual inspection is often the first method by which a pending problem is identified.

When relays are received on site for a new installation, a visual inspection should be one of the first tasks performed. Visual checks are used to verify that the shipment includes such items as the correct relay model, power supply voltage, and binary input/output voltage.

6.3.2 Mechanical Checks

Mechanical checks are practically nonexistent in the context of microprocessor relays. Certain mechanical checks may be necessary on certain relays. In relays that utilize printed circuit board jumpers, a mechanical inspection/configuration may be necessary before commissioning the relay. Where mechanical connections exist, they must be firmly seated to ensure a reliable electrical connection. A printed circuit board's connection to the relay chassis and interconnecting ribbon cables must be secure.



Key O&M Cost Point

Mechanical checks are practically nonexistent in the context of microprocessor relays.

6.3.3 Electrical Tests

Electrical tests are performed to verify that performance characteristics are acceptable under a controlled set of input conditions. Electrical tests confirm that the correct protection settings are applied to the relay and that the proper output contact is actuated by each protection function. Once performed as a part of initial commissioning, other methods of verifying relay operation (such as event report scrutiny or go/no-go functional tests) may be substituted.

In microprocessor relays containing programmable logic controllers, the protection control scheme is increasingly migrating from external wiring and auxiliary relays to integration into the relay itself. User-created logic, which in older generations of relays was engineered and verified by the relay manufacturer in extensive factory model power system type tests, should be electrically tested to ensure proper operation. In the same way, extensive modifications to internal logic may require electrical testing to ensure that no unintended side effects are introduced into the overall operation of the logic.

**Key Technical Point**

User-created logic, which in older generations of relays was engineered and verified by the relay manufacturer in extensive factory model power system type tests, should be electrically tested to ensure proper operation.

Electrical tests also provide diagnostic information regarding the condition of a relay and its components. Electrical testing of protective relays requires specialized test equipment.

6.3.4 SCADA Checks

Developments in the area of substation automation have led to the integration of SCADA functions into the microprocessor relay. Analog measurement values, binary status bits, and momentary change detection (MCD) logic resident in the relay must be verified to the SCADA master. Analog measurements can be verified by current and voltage injection. Depending upon the effective scan rate of the SCADA master, transient events such as relay pickups and trips may require the relay to provide momentary change detection logic. MCD logic points can be verified to the SCADA master during functional tests. Binary status points can be easily checked by relay software that allows internal SCADA protocol points to be asserted by a locally connected personal computer.

6.3.5 Functional Checks

For protective relays, a functional check is conducted to verify that the desired protective action occurs in response to a relay operation. In most cases, a functional check is based on ensuring that a circuit breaker opens when the relay's main contacts are closed.

Functional tests may be accomplished using current and voltage injection; however, microprocessor relays allow the user to connect locally or remotely with a personal computer and to electronically force output contacts to change states. This method can be used to verify the operation of external devices such as circuit breakers and to confirm the control scheme wiring external to the relay. This is especially efficient if the relay has been tested previously using voltage and current to verify all internal settings and logic connections to the proper outputs. There is a trend in protective relays to supply a single relay management software program that combines relay settings, file management, relay communications software, graphical logic, PLC programming tools, commissioning/testing tools, metering, SCADA protocol configuration tools, oscillography, sequence of events, and spontaneous alarm functions. This makes functional testing easy to accomplish even without voltage and current test systems.

**Key Human Performance Point**

Microprocessor relays allow the user to connect locally or remotely with a personal computer and to electronically force output contacts to change states. This method can be used to verify the operation of external devices such as circuit breakers and to confirm the control scheme wiring external to the relay.

By applying power supply voltage to the relay and connecting with a personal computer equipped with the relay's graphics, communication, settings, and diagnostic software, all binary outputs and LED indications can be forced into changing states. By using this opportunity to also apply DC voltage to verify binary inputs, the entire binary I/O subsystem of the relay can be confirmed. Identifying inoperative relays (or relays that do not have the proper power supply or binary input voltages) early in an installation allows time for corrective action to be taken without impacting the overall project schedule. This feature also allows incoming receipt testing of relays early in the initial installation process before the relay is mounted on the panel and the wiring is completed.

**Key O&M Cost Point**

Identifying inoperative relays (or relays that do not have the proper power supply or binary input voltages) early in an installation allows time for corrective action to be taken without impacting the overall project schedule.

6.3.6 Relay Data Logs

The microprocessor relay provides a great deal of information for local retrieval or for data transmission including operational indications and alarms, operational measured values and metered values, fault recording, and oscillography data. This information can be read out and is available from the relay's memory using a personal computer and relay management software.

**Key Human Performance Point**

The microprocessor relay provides a great deal of information for local retrieval or for data transmission including operational indications and alarms, operational measured values and metered values, fault recording, and oscillography data.

Relay data logs are an effective tool for electrical testing, functional testing, and troubleshooting. During electrical testing, whether with computer controlled or manual test systems, it is effective

to connect a computer to read real-time metering and operational data from the relay. “Tiling” multiple windows on the computer may be possible to view the following information or screens simultaneously:

- Relay test system control software showing applied voltage, currents, and sensing/stop contact input status
- Relay management software real-time metering window (including positive, negative, and zero-sequence metering)
- Relay management software calculated operational quantities (that is, synchronizing relay Δ voltage, Δ frequency, and Δ angle values, or transformer differential and restraint currents)
- Relay management software spontaneous operational events and alarms

Most of the difficulties in electrically testing microprocessor relays are actually errors in the test connections or methods. Using relay data logs and real time metering can help to identify and correct testing errors quickly. Using the method described above, common test set connection errors can be identified by applying symmetrical full load quantities to the relay and observing the real time metering window of the relay management software. If sequence components are present, it is a clear indication of rolled test set connections. The improperly connected phase can be easily found by turning off the voltage and current inputs one-by-one and observing which phase in the metering window goes to a zero magnitude.



Key Human Performance Point

Most of the difficulties in electrically testing microprocessor relays are actually errors in the test connections or methods.

The ability to simultaneously view in real time what is being applied to the microprocessor relay and how the relay is responding makes testing and troubleshooting relatively simple.

6.3.7 In-Service Measurement Readings

Many of the benefits of modern relay management software that were described in Section 6.3.6 also apply to in-service readings and commissioning tests. The ability of the relay management software to simultaneously “tile” windows containing real time metering and relay operational data logs provides a noninvasive manner of recording in-service readings. The relay management software and the personal computer greatly reduce setup time and replace many types of test equipment (such as ammeters, voltmeters, and phase angle meters) that were used formerly to take in-service readings. The potential for false trips during in-service readings is reduced by eliminating the need for direct connections to the relay current and voltage circuits.

**Key O&M Cost Point**

The relay management software and the personal computer greatly reduce setup time and replace many types of test equipment (such as ammeters, voltmeters, and phase angle meters) that were used formerly to take in-service readings.

6.4 Determining Maintenance Intervals

Microprocessor relays may use internal batteries to maintain nonvolatile memory. Such batteries commonly have a life span of 10 years. Manufacturers recommend changing the batteries prior to their end of life.

A typical interval for periodic maintenance for numerical relays is 4–8 years. Circumstances may exist in which testing a protective relay, or group of relays, at an interval less than 4 years or greater than 8 years is appropriate. However, a range of 4–8 years covers most reasonable contingencies. This wide range provides the flexibility needed to optimize maintenance intervals and fully account for the many factors that influence relay maintenance practices.

**Key O&M Cost Point**

A typical interval for periodic maintenance for numerical relays is four to eight years.

Electrical tests vary depending on the type of relay and its construction. Because each type of relay is unique in design and construction, electrical tests for similar types of relays will vary for different makes and models. The manufacturer's guidance must be used in conjunction with the maintenance tasks discussed in this document to ensure adequate testing of a specific type of relay.

Modern test equipment is capable of waveform playback. Numerical relays are capable of recording faults and other transient events. Testers are increasingly using actual fault records and playing them back through automated test equipment to verify the relay design and/or settings. In addition, event logs and trip logs can be used to measure the relay performance after a fault occurs. If the relay performs within the design, the protection system owner may determine that the window for periodic maintenance can be shifted to a later schedule.

**Key O&M Cost Point**

Event logs and trip logs can be used to measure the relay performance after a fault occurs. If the relay performs within the design, the protection system owner may determine that the window for periodic maintenance can be shifted to a later schedule.

The relay manufacturer's instruction and maintenance books, and testing methods developed by the protection system owner's testing methods, are typically used as the primary source of information in testing and maintaining protection systems. Industry operating data and manufacturer service advisories may indicate certain deficiencies in relay or scheme designs that may require additional specialized test methods.

The periodic test intervals of the primary equipment should also be considered. It may be determined to be more efficient to coordinate the relay maintenance intervals with the primary equipment maintenance.

6.5 Summary of Maintenance Practices

6.5.1 Initial Inspection

A general inspection should be performed to verify that no shipping damage has occurred to the device. The relay should be checked for proper ratings, correct communication ports and protocols, and the correct number of binary inputs and outputs. Minimal checks are required initially because a full series of inspections and tests will be performed at the time of installation. However, if the relay is intended as a spare or will not be installed in the near future, a more detailed receipt inspection is appropriate. In this case, checks should be performed to verify that the relay was received in good working order.

6.5.2 Mechanical Checks

Numerical relays have no moving parts; therefore, the mechanical inspection is minimal. An inspection of the relay terminals and the communication ports should be performed. Numerical relays may be provided with PC card jumper links to obtain a specific pickup range associated with the binary inputs, binary outputs, current, and voltage inputs. If the link settings are not specified in the manufacturer's documentation, an inspection of the link settings should be made.

6.5.3 Electrical Tests

The philosophy for testing the elements within a multifunctional relay varies. A thorough evaluation of each element should be performed on any new numerical relay product before it is installed on a system to check that each meets the owner's design criteria and stated tolerances.



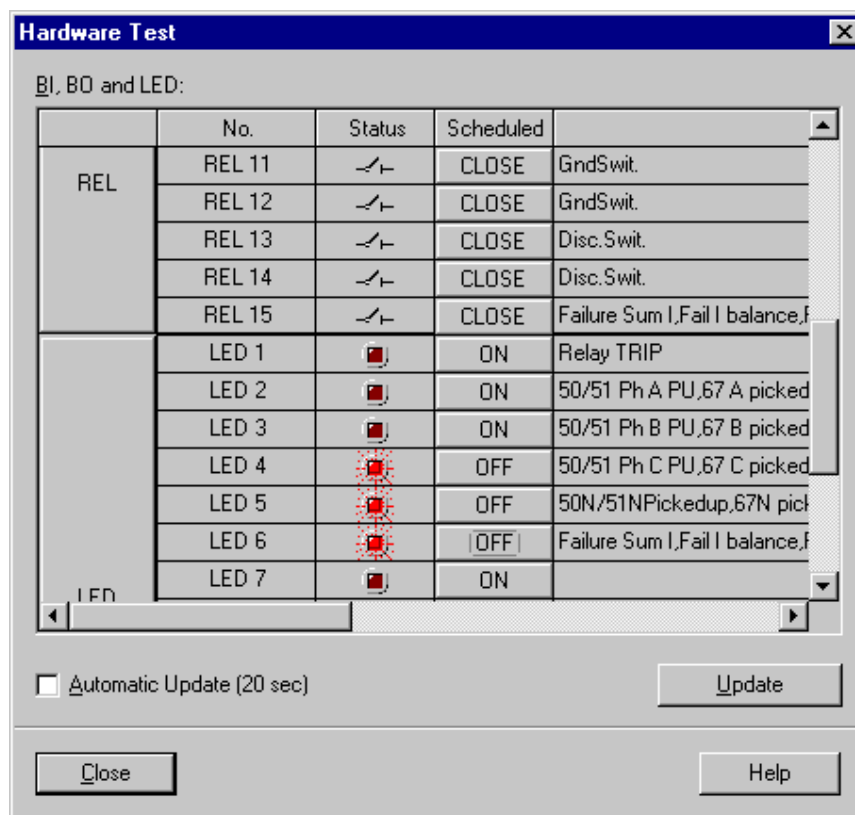
Key Technical Point

The philosophy for testing the elements within a multifunctional relay varies. A thorough evaluation of each element should be performed on any new numerical relay product before it is installed on a system to check that each meets the owner's design criteria and stated tolerances.

After the relay has been evaluated and placed in service, only those elements that are being used for the specific application need to be tested by measuring the pickup accuracy or performing a GO/NO-GO functional test. It is not necessary to test those elements that are disabled.

6.5.4 Functional Checks

Functional testing is required to verify that the intent of the protection system is being carried out. Because numerical relays require no calibration, the functional check proves that the relay element outputs are operating the equipment and, therefore, are proving the overall scheme design. This test can be initialized by using a relay test set to activate the relay element or by using the relay configuration software commissioning tools if available through the relay manufacturer (see Figure 6-1).



Hardware Test				
BI, BO and LED:				
	No.	Status	Scheduled	
REL	REL 11	✓	CLOSE	GndSwit.
	REL 12	✓	CLOSE	GndSwit.
	REL 13	✓	CLOSE	Disc.Swit.
	REL 14	✓	CLOSE	Disc.Swit.
	REL 15	✓	CLOSE	Failure Sum I,Fail I balance,f
LED	LED 1	■	ON	Relay TRIP
	LED 2	■	ON	50/51 Ph A PU,67 A picked
	LED 3	■	ON	50/51 Ph B PU,67 B picked
	LED 4	■	OFF	50/51 Ph C PU,67 C picked
	LED 5	■	OFF	50N/51NPickedup,67N pick
	LED 6	■	OFF	Failure Sum I,Fail I balance,f
	LED 7	■	ON	

☐ Automatic Update (20 sec)

Table 6-1
Relay Commissioning Tool



Key Technical Point

Because numerical relays require no calibration, the functional check proves that the relay element outputs are operating the equipment and, therefore, are proving the overall scheme design. This test can be initialized by using a relay test set to activate the relay element or by using the relay configuration software commissioning tools.

6.5.5 Post-Repair

Numerical relays are provided with watchdog contacts and can have self monitoring to immediately signal a relay problem or failure. If it is determined that the relay requires repair, certain steps should be followed to repair the relay and place it back in service. It is recommended that the relay be taken out of service and that the associated primary equipment be isolated while the repair tasks are being performed.

If the failure is significant, a complete replacement may be required. After the repaired or replaced device is connected, all visual, electrical, and functional tests should be performed to verify that the relay and primary equipment are operating correctly.

Components unaffected by the repair or replacement need not be disturbed. A full set of electrical tests should be performed to verify that the relay settings have not been inadvertently changed during the repair.

7

REMOVING NUMERICAL RELAYS FROM SERVICE

7.1 Preparation

The maintenance and testing described in Section 6 requires that the relay be removed from service. To efficiently remove the relay from service and place it back into service, certain basic steps should be performed. Failure to enable a relay program following the use of a temporary program specifically designed to test a subset of the functions in the overall protection scheme is a common mistake.



Key Human Performance Point

Failure to enable a relay program following the use of a temporary program specifically designed to test a subset of the functions in the overall protection scheme is a common mistake.

The following list of activities is provided to help prevent this type of common oversight:

- Ensure that the most recent master relay setting file, relay test equipment, personal computer, and communication cable are available.
- Review schematics and/or circuit diagrams as appropriate to ensure that the consequences of removing the relay from service are known.
- Review internal relay programmable logic and communication networking to ensure that automatic control or tripping logic will not have an adverse effect when the relay is removed from service. Numerical relays have the ability to pass tripping signals to other numerical relays via communication. Remove any communication channels that allow the relay to be tested and to send trip signals remotely to relays that may be outside the area of the test zone. Verify loss of communication at the remote devices before testing any functions in the local device.
- Review pertinent relay-setting data sheets and record relevant information on the relay test and inspection sheet.
- Contact any SCADA/load dispatchers who may be receiving data from the relay and notify them that the data will be lost while the relay is taken out of service. Disconnect communication from the relay to SCADA so that false data are not supplied to SCADA while the relay is in test.
- Upload any event files and oscillography files that may be in the relay before testing is started.

7.2 Removing From Service

7.2.1 Purpose

Protective relays are inactive devices by nature and are not typically exposed to extreme operating or environmental conditions.

Removing the relay from service will allow the tester to perform a visual inspection of the relay faceplate and terminal connections and prepare the relay for connection to the relay test equipment and personal computer equipment.

7.2.2 Procedure

The following procedure should be followed:

- Ensure that plant conditions are consistent with the work to be performed and obtain permission to remove the relay from service. Always be aware of any abnormal plant condition or system lineup that may be impacted by removing the relay from service. Additional caution should be exercised during outages or periods of heavy maintenance.
- Tag the relay out-of-service in accordance with plant procedures.
- Isolate the relay from external circuits. This action is completed by removing the attached test plug or opening panel test switches. An inadvertent operation may occur if the proper sequence is not followed. Outputs capable of generating trips (trip outputs, BFI [breaker failure initiate] output, or DTT [direct transfer trip] output) should be defeated prior to opening test switches for operating and restraining quantities. Follow the manufacturer's guidance for the proper sequence when opening switches. Use caution to make sure ground trips are not generated by applying three-phase currents sequentially. Always insert current and voltage test blades and verify that no trip outputs are sealed prior to closing output contact test blades.
- Clean the outside of the relay faceplate and cover to remove any contaminants or dirt. (CAUTION: Take care not to operate any function keys or control keys that could reset or operate other equipment until they have been isolated.)

7.3 Numerical Relay Programming Considerations

Numerical relays are built using a microprocessor, an analog to digital converter, memory components that hold the relay algorithms, binary inputs and outputs to control equipment, and communication ports connected to control rooms and operating centers.

The relay settings are defined by the relay algorithms in the relay memory. Automatic controls may also be programmed into the device's logic control capability that must be considered when tests are performed.

7.3.1 Alternate Setting Groups

Numerical relay manufacturers provide relays with the capability of having multiple setting groups that can be applied locally at the relay (using automatic logic to switch for changing system conditions) or that can be applied remotely via a system interface (SCADA).



Key O&M Cost Point

Numerical relay manufacturers provide relays with the capability of having multiple setting groups that can be applied locally at the relay (using automatic logic to switch for changing system conditions) or that can be applied remotely via a system interface (SCADA).

Using alternate setting groups increases the opportunity for errors and testing requirements. Multiple setting groups are used less frequently than single setting groups, but if the state of the power system changes significantly, a single setting program may be inadequate or wrong. For this reason, multiple setting groups allow the relay engineer to adapt to significant changes in the system. This adaptive relaying is a relatively simple solution. However, it may require careful and extensive studying of the system under different configurations to determine if multiple settings are required.

7.3.2 Alternate Setting Test File

It is imperative that someone within the relay organization maintain a master setting file after the initial settings have been applied and the numerical relay is placed in service. One technique used so that the master file does not get modified when maintenance is required is to create an alternate setting file. This file is developed from the master file to use specifically for testing the various elements within the relay.



Key Human Performance Point

One technique used so that the master file does not get modified when maintenance is required is to create an alternate setting file. This file is developed from the master file to use specifically for testing the various elements within the relay.

Numerical relays are also called multifunctional relays for a good reason. One relay can have several protection functions enabled within the device and in some cases the number of functions can be quite extensive. This creates a problem for the tester because under certain test conditions, multiple elements may operate when the test set quantities are applied or when each of the functions could possibly be assigned to one trip output. This is a situation in which the alternate setting test file is needed.

Alternate setting files can be created by copying or using a variant of the master file to set up test files so that all of the functions enabled within a numerical relay can be individually tested. The

test file may have certain functions turned off so that others can be tested or the trip outputs may be temporarily assigned to spare outputs of the numerical relay for connection back to the test set to signal a specific element trip.

One precaution that should be included within the maintenance procedure is that the master setting file should be reloaded into the numerical relay after all testing is complete. It should also be checked to see that the primary protection operates the connected equipment as designed.

7.3.3 Disabling Elements for Tests

For the purpose of testing each element within a numerical relay, the relay tester must modify the master setting file by blocking or turning off specific elements so that other elements can be checked for operation.

In most cases, disabling the elements can be done from the front display of the numerical relay. However, a more efficient method is to disable the relay using the relay configuration software via the connected personal computer. If the test equipment has output contacts that can be configured to control the relay, it is also possible to block certain elements within the relay by connecting to a binary input to control the relay block function. The most widely used technique and the simplest to configure is simply turning elements on and off throughout each test.

After the tests have been performed, the master setting file should be reloaded into the numerical relay and checked to see that the primary protection operates the connected equipment as designed.

Additionally, the test personnel should upload event logs and oscillography files from the relay as part of the documentation process after testing the relay. They should then delete these files and clear any targets before placing the relay back in service.

Many relays include predictive maintenance data such as I2T and breaker operation counters. If possible, the relay tester should record the values for these parameters prior to testing and should reset the parameters to those values when the testing is completed.

As part of the final test documentation, the relay tester should record the serial number and any hardware and firmware version numbers of both the relay and the relay configuration software. These data should be included with the settings tested (including the master file and any alternate setting files), the test points that were applied for each element, and the results. Newer microprocessor-based relay test sets allow the user to combine all of this information in final test reports.

8

ELECTRICAL TESTS

Section 8 provides information regarding electrical tests for protective relays. This information is intended to help plants establish and/or refine their protective relay maintenance practices consistent with their overall maintenance objectives.

This section emphasizes the following points :

- The purpose of each test
- How to perform each electrical test

The purpose of each electrical test is discussed and procedures for testing and calibration are outlined. The sections that discuss procedure are intended to capture the essence of how to accomplish each electrical test. The information presented here should be supplemented with manufacturer and plant-specific information to create actual field procedures.

8.1 Test Preparation

8.1.1 Test Equipment

Several types of relay test equipment are available. It is recommended that a computer-controlled, three-phase digital test system be used when testing digital/numerical relays. These test sets provide software that facilitates an easy setup to test a relay. The modern test sets provide software modules that include numerous considerations that make testing complex multifunctional digital/numerical relays possible.

Proper operation of the test equipment is vital to obtaining good test results. It is advisable to ensure that all personnel conducting relay testing are familiar with the test equipment and its limitations.

Numeric relays are more difficult to test than previous generations of relays because they have the intelligence to recognize the dynamic states and failures of the measurement inputs. Tests traditionally performed on electromechanical relays may not achieve proper results as the numeric relay diagnoses the test inputs as current anomalies or voltage input failures. Personnel conducting relay tests must also have a thorough understanding of the application and capabilities of the relays in order to design and execute successful electrical tests.

**Key Human Performance Point**

Numeric relays are more difficult to test than previous generations of relays because they have the intelligence to recognize the dynamic states and failures of the measurement inputs.

8.1.2 General Test Considerations

The type of unit being tested and the goal of the tests should be considered when determining whether automated or manual testing is required.

In automated testing, several automated test routines may be available that will accomplish the same results. Variations in automated test procedures include whether the test quantity will be ramped or pulsed, the duration of the test pulse, the maximum applied quantities that will be permitted, and the test quantity offset magnitudes.

Automated tests also require an indication of relay output. Careful consideration should be given when choosing the output contact indication. The actual trip contact may be used or it may be advantageous to use a spare output contact or another specially designated test output contact. Automated test systems must also be configured for the method of indicating an output, whether a normally closed or normally open dry contact, or the presence or absence of voltage across a contact.

Test methods may require that certain measurement input features of the relay's self diagnostics (such as fuse failure or current anomalies) be temporarily disabled.

**Key Human Performance Point**

Test methods may require that certain measurement input features of the relay's self diagnostics (such as fuse failure or current anomalies) be temporarily defeated.

8.2 Insulation Resistance Test**8.2.1 Purpose**

The purpose of an insulation resistance test is to identify any measurable deterioration in a relay system's insulation. Of particular importance are CT circuits. Service conditions such as high temperature, humidity, precipitation, contamination, vibration, and physical abuse can degrade insulation integrity.

An insulation resistance test set consisting of an AC or DC voltage source is applied from the relay circuit test point to ground. The voltage level at which the insulation resistance test may be applied varies for each microprocessor relay subsystem. Current inputs, voltage inputs, and output relays should withstand test voltage magnitudes up to 2.5 kV rms (AC). Power supplies

and binary inputs may be rated for insulation resistance test voltages up to 3.5 kV DC. Communication terminals, time synchronization interfaces, and analog outputs may not be rated for insulation testing or may be limited to applied voltages of 500 V rms (AC). In all cases, the manufacturer's specifications should be consulted prior to performing high-voltage insulation resistance testing.

8.2.2 Procedure

8.2.2.1 Current Circuit

It may be desired to test the insulation resistance of the entire current circuit as a system. In this case, all CT grounds should be temporarily removed from the circuit and the insulation resistance test set should be connected from the current input to ground.

After obtaining the test results, the CT ground should be restored. A good practice is to repeat the insulation test after replacing the CT ground to verify a reading of zero, thus confirming that the CT ground was indeed restored.



Key Technical Point

After obtaining the test results, the CT ground should be restored. A good practice is to repeat the insulation test after replacing the CT ground to verify a reading of zero, thus confirming that the CT ground was indeed restored.

If the relay is being bench tested, the relay case/chassis must be properly grounded. The test from each current circuit terminal should be applied to ground.

8.2.2.2 Voltage/Power Supply/Binary Inputs

The relay case/chassis must be properly grounded and the voltage inputs disconnected from any external ground connection. The test voltage from each voltage input terminal should be applied to ground.

8.2.2.3 Output Contacts

The test voltage should be applied across open-trip circuit contacts and it should be verified that the reading is acceptable.

8.3 Pickup, Dropout, and Timing Tests

8.3.1 Purpose

The purpose of a pickup test for an inverse-time unit is to verify that the tap setting has been correctly programmed into the relay. The pickup point is the minimum signal needed to cause the time curve algorithm to begin timing and eventually close the contacts. In theory, a steady signal equal to the pickup value requires an infinite amount of time to close the contacts. In practice, the pickup point can be tested by programming the test output contact to close for the pickup of the time curve logic instead of the trip output of the timer.

8.3.2 Pickup Test Procedure

In order to check the relay pickup point, the tester must first be sure to understand the function as described in the relay manual. A good understanding of the feature under test is essential. Digital relays typically react on dynamic conditions and not static conditions as with electromechanical relays. The following steps should be followed to perform a pickup test of a digital relay.

1. Read the relay manual section describing the protective function operation and test procedure.
2. Assign the protection function *relay pickup* to a binary output contact. Ensure that nothing else is assigned to the contact.
3. Disable all other available protective functions.
4. Connect test equipment binary input to the relay output contact.
5. Connect the test equipment analog output signals to the analog inputs of the relay under test. Check the user's manual for the correct connection.
6. Inject an increasing or decreasing analog value until the relay picks up. It is essential to inject the correct type of fault. A digital overcurrent relay will require the tester to inject fault currents in both phases in order for a phase-to-phase pickup to occur. Digital relays will have logic to identify the fault type. Multifunctional overcurrents will pick up on a ground fault if current is injected in only a single phase. (On electromechanical relays, the pickup was associated with a single device.)
7. Use the relay testing, measurements, and fault event functions to provide feedback on how the relay reacted to the test. The relay software typically provides tools to help the tester test more effectively and efficiently.

8.3.3 Dropout Test Procedure

Dropout testing can typically be completed at the same time as the testing of the pickup of a digital relay. Digital relays do not store mechanical or thermal energy and are not slow to reset.

Digital relays can reset instantaneously. Many relays provide the user the ability to reset using a time delay. Therefore, this type of testing is not essential unless the relay is used with electromechanical relays on the same system.

8.3.4 Timing Tests

This test verifies that the tap, time curve, and time dial settings have been programmed into the relay properly. The following steps should be followed to perform a timing test:

1. Assign the protection function *relay trip* to a binary output contact. Ensure that there is nothing else assigned to the contact.
2. Disable all other available protective functions.
3. Connect test equipment binary input to the relay output contact.
4. Connect the test equipment analog output signals to the analog inputs of the relay under test. Check the user's manual for the correct connection.
5. Using the time curve equation given in the manufacturer's instruction manual, calculate the expected time delay for each multiple of tap to be tested. Alternatively, use the manufacturer's time curves to estimate the pickup time for each test point magnitude.
6. Suddenly apply the test quantity and simultaneously trigger the test system timer.
7. After the contacts are closed indicating the time curve has been asserted and issued a trip, note the time delay and compare to the expected value.

8.4 Microprocessor Impedance Element Test

8.4.1 Purpose

Impedance elements have traditionally been used to provide phase and ground distance protection in a variety of applications including the protection of transmission lines, distribution circuits and generators. Various types of impedance characteristics are employed including mho circle units (with and without offset) and noncircular characteristics including lenticular, tomato, and quadrilateral.

Regardless of characteristic type, electrical testing of microprocessor impedance elements is to confirm the proper size, shape, and angle of the characteristic. The battery of tests necessary to achieve this goal varies somewhat for each type of characteristic. Test methods can vary based upon the user's overall testing philosophy, the type of test system employed, and the use of automated (computer-controlled) versus manual testing.

8.4.2 General Test Precautions

Several general precautions should be observed when testing microprocessor impedance elements:

- In step-zone protection schemes, care should be taken to isolate only the unit under test. Over-reaching impedance elements should be defeated or the zone under test should be programmed to a dedicated binary output to ensure proper results. If a dedicated binary output (such as a spare contact) is used for testing, at least one test should be performed to the actual binary output contact used for external tripping. This verifies that impedance element logic is programmed to actuate the proper binary output. If the actual trip output contact is temporarily reprogrammed to isolate the element under test, care should be taken to verify that the programming of the binary output is restored to its in-service value when testing is completed.
- Measurement supervision functions that impede the operation of the impedance elements should be defeated. Loss of potential, fuse failure, and current monitoring functions may operate during the normal course of the relay test. These functions should be defeated. Using relay management software to monitor spontaneous alarms during testing can help identify any measurement supervision function that is inhibiting the proper testing of impedance elements.
- Tests should be designed to insure that the applied quantities meet minimum current and voltage supervision settings.

In both automated and manual testing, the size and shape of the impedance circle is tested by applying a voltage and current to the relay at a specific phase angle. The pickup of the relay is found either by holding the voltage magnitude constant and raising the current or by holding the current magnitude constant and lowering the applied voltage. The duration of the applied fault must exceed the maximum operating time of the impedance element + trip output time + margin.



Key Technical Point

If a dedicated binary output (such as a spare contact) is used for testing, at least one test should be performed to the actual binary output contact used for external tripping.

8.4.2.1 Circular, Lenticular, and Tomato Impedance Elements

The laws of geometry dictate that a minimum of three points is necessary to define a circle. Circular impedance elements require at least three test points to verify the size and shape of the characteristic.

Various points on the circle are tested by adjusting the phase angle between the applied current and voltage. In order for all three test points to pick up at the anticipated impedance value, the size, shape, and angle of the characteristic must be within tolerance. No further testing is required.

Automated test systems can enable efficient testing and plotting of the entire impedance characteristic. The number of points plotted and the resolution of the plot can be adjusted by the user.

8.4.2.2 Offset Circular/Tomato Impedance Elements

When an impedance characteristic does not pass through the origin of the R/X diagram, it is said to be offset. Offset characteristics are tested in the same manner as the non-offset characteristics, but an additional test point should be included to verify the reach of the offset portion of the characteristic.

8.4.2.3 Quadrilateral Impedance Elements

To provide good coverage for resistive ground faults, quadrilateral or polygonal elements may be applied. Quadrilateral characteristics are generally constructed by combining an upper and lower reactance line with a left and right resistance line.

It is necessary to test at least one point on each of the lines of the characteristic to fully verify a quadrilateral characteristic. If the bottom reactance line goes through the origin of the R/X diagram, it may be possible to forego testing this line of the characteristic.

The simplest approach to quadrilateral testing is to choose a test point along the R/X axis. One test point per axis is sufficient.

8.5 Differential Protection Tests

8.5.1 Purpose

Differential protection tests are designed to electrically verify all of the functions of a percent-restrained differential relay.

8.5.2 Minimum Pickup Tests

Minimum pickup of each winding should be tested. Three-phase tests are recommended. Single-phase tests may conclude different results depending upon the specific transformer and CT connections and the relay's method of zero-sequence compensation.

8.5.3 Slope/Through-Fault Test

To prevent misoperation during periods of heavy through-fault current and possible CT saturation, percentage differential relays provide one or more slope settings to restrain the differential element for the through-fault condition without compromising the differential unit sensitivity. One test point should be verified on each slope of the differential characteristic.

To test the slope characteristic, test currents must be loaded into two windings of the relay. The current magnitudes and angles should be initially set so that the differential operate current is zero and the value of $I_{\text{RESTRAINT}}$ falls within the desired slope of the characteristic curve. From this state of zero operate current, the tester should vary the angle of the currents in one winding to create an imbalance and resulting differential current. The tester should continue to vary the current angles until the relay's differential element operates. The values of I_{OPERATE} and $I_{\text{RESTRAINT}}$ should be consistent with the slope setting being tested. By increasing the value of $I_{\text{RESTRAINT}}$, any additional slope settings can be tested in a similar manner.

A relay with three or more windings should be tested as a two-winding relay. The tests should be repeated until each winding has been verified.

8.5.4 Second/Nth Harmonic Restraint Tests

Harmonic restraint is used to prevent improper trips when initially energizing a transformer. It is normally expressed as a percentage of the fundamental operating current.

Harmonic restraint can be tested by loading equal quantities of second harmonic test current and 60 Hz in parallel into one winding of the relay. The current magnitude should be greater than the minimum pickup of the winding under test. The harmonic current is decreased until the relay operates.

8.5.5 Instantaneous Tests

Instantaneous units are unrestrained overcurrent elements. They should be tested in the same manner as minimum pickup. Caution should be exercised to minimize the amount of time that high-magnitude currents are applied to the relay. The manufacturer's specifications should be consulted to avoid exceeding a relay's short-time current rating.

9

NUMERICAL RELAY MAINTENANCE PROGRAM GUIDELINES AND CONSIDERATION

9.1 Maintenance Philosophy for Numerical Relays

Testing and maintaining power system equipment efficiently requires that the appropriate resources are allocated for the equipment tests. Conventional tests that apply to older relays may no longer apply to numerical relays. One of the key advantages of a numerical relay is the feature of having continuous self monitoring. With this capability, a different maintenance strategy must be employed. In comparison to analog protection, routine maintenance can be substantially reduced. Manufacturers of numerical relays state that little or no maintenance is required in most cases. The trend for maintaining protective relays today is toward event-based maintenance and repair.

In the past, specific elements within a relay were calibrated using relay test equipment to test the pickup values in order to prove that the set-point operation was within a specific tolerance. Numerical relays no longer require calibration. There is no way to adjust the pickup of the relay except through a software setting change or possibly through PC card link settings. Today, relay maintenance philosophies emphasize testing the complete protection scheme versus the specific relay element to prove that the external controls and the primary equipment operate according to the scheme design and operating characteristics.



Key O&M Cost Point

Numerical relays no longer require calibration. There is no way to adjust the pickup of the relay except through a software setting change or possibly through PC card link settings.



Key Technical Point

Today, relay maintenance philosophies emphasize testing the complete protection scheme versus the specific relay element to prove that the external controls and the primary equipment operate according to the scheme design and operating characteristics.

Where relays are networked or connected to a remote relay scheme, new test methods include using GPS satellite synchronized test equipment to test the overall protection scheme operation

using end-to-end testing. Even though this form of testing requires more time and possibly additional for test equipment setup, the tests may yield relay problems that go undetected when using individual relay element tests. This type of testing has been slow to develop and is typically used on transmission line terminals having complex protection schemes.

During recent years, the philosophy of identifying the correct test intervals has been thoroughly discussed and studied. Companies that have set up reliability-centered maintenance programs (RCM) have included relay maintenance within these types of programs. A variety of parameters are measured using the operating history of relays and the primary equipment to which they are connected. Other companies still survey the industry to determine the preferred maintenance interval trends and set them accordingly. Regulatory and government agencies in some areas may dictate the intervals. Regarding maintenance intervals, one trend is common—relay maintenance intervals have continued to be extended because of the improved operating history of numerical relays.

9.2 Maintenance Program Objectives

The primary objective of a good maintenance program is to ensure that protection is available and to minimize faulty operation. Maintenance also allows the user to extend the life of the protection equipment by identifying potential problems that could be detrimental to the relaying before the problem occurs.

The availability of protection is substantially increased by self monitoring. Studies by the German Utility Board (VDEW) have measured the availability of relays with and without self monitoring. These studies have shown that without self monitoring, the number of failed devices increases sharply with increasing service time. (For more information see Gerhard Ziegler's book entitled *Numerical Distance Protection: Principles and Application*.) With monitoring, the percentage of failed devices is reduced. The combination of continuous monitoring and routine maintenance at longer intervals has proven itself to be a balanced approach.



Key Technical Point

Without self monitoring, the number of failed devices increases sharply with increasing service time. (For more information see Gerhard Ziegler's book entitled *Numerical Distance Protection: Principles and Application*.) With monitoring, the percentage of failed devices is reduced.

9.3 General Recommendations

The following lists contain general recommendations regarding checks and tests:

- Simple Function Check
 - Verify that settings in the relay are correct by comparing to the setting sheet or database
 - Compare the operational measured values (V, I, Watts, or Vars) indicated by the relay with the data obtained from an independent operational measurement
 - Conduct a trip test
 - Read out and evaluate the event log recordings
 - Check the protection fault recordings and communication signals
- Protection Test (with test equipment)
 - Verify that the settings in the relay are correct by comparing to the setting sheet or database
 - Check one measured value in each of the input channels (V&I) and compare it with the display of the relay or connected test personal computer
 - Check that the binary inputs and outputs that are utilized included the operation of the primary switching equipment
 - Read out and evaluate the event that recorded a disturbance
 - Check the interfaces to computers and SCADA
 - Read out the setting parameters and compare to the required values
 - Check the protection fault recordings and communication signals

9.4 Design Basis Maintenance

The design basis and purpose of protective relays must be fully understood before applicable maintenance and test requirements can be established. By understanding the design basis, the maintenance department can tailor the periodic inspection, test, and maintenance requirements to achieve the desired level of reliability. Design basis information includes but is not limited to the following:

- The specific purpose of the relay (under what fault or abnormal condition is the relay expected to operate)
- Relay operating parameters and settings (such as pickup points, CT ratios, tap settings, or time dial settings)
- The selectivity, coordination, and accuracy requirements for the relay

- The QA classification of the relay and the associated environmental requirements
- Regulatory commitments or internal practices that impact planning, scheduling, performance, or documentation of relay maintenance

9.5 Practical Considerations

Abstract and theoretical approaches to practical maintenance issues are generally less effective than simple, straightforward practices. Complex programs are considerably more difficult to keep focused in the nuclear environment.

It has always been difficult to determine how often relays should be maintained because of their overall good performance history. The problem is that relays are typically on standby, waiting for a fault or abnormal event to occur. A relay may not be called upon to operate for several years. But when the relay is called upon to operate, it must do so correctly to minimize outage times and equipment unavailability. If it operates incorrectly, in many cases the misoperation is viewed as a high-profile event and many questions are directed to the relay engineer. Explanations of why the misoperation occurred and recommendations on how to prevent it from occurring again are required. Maintenance intervals are set up on a reoccurring basis to keep faulty operation to a minimum.

Not all relays have equal importance and, therefore, they should not receive equal attention. An arbitrary decision to standardize all maintenance to the same level and test frequency can become a great burden on maintenance department resources. Each maintenance department has limited resources—these resources should be applied in a manner that provides maximum payback in overall plant reliability.

9.6 Personnel Training

Maintenance and testing of protective relays requires considerable expertise and experience. For this reason, most relay work is performed by dedicated relay specialists (someone whose work duties are substantially limited to relays). Very few utilities use nondedicated personnel for protective relay maintenance.

Numerical relays require the use of a personal computer. The skills to use a PC and multiple relay software packages is required. The ability to evaluate network communication and protocol information is also necessary.

Proper training of personnel is an integral part of a successful maintenance program. Properly trained workers directly support plant safety and reliability. Improperly trained personnel make mistakes or overlook problems. In particular, protective relays require well-trained and skilled personnel to ensure effective maintenance.

Personnel involved with protective relay maintenance should receive thorough training. Training should include formal classroom work; however, protective relay training programs should stress practical hands-on work. Sources of formal training include the following:

- In-house training
- Industry workshops
- Manufacturer's classes for test equipment
- Relay manufacturer's training
- Other specialized courses

Relay maintenance is very much an acquired skill. For this reason, on-the-job training should be made an integral part of the training program. On-the-job training is most effective when a concerted effort is made to pair junior personnel with an experienced, knowledgeable group lead or partner.

An area of training that should not be overlooked involves test equipment and personal computers. Protective relay test sets are very specialized equipment. Considerable knowledge is required to operate them correctly. Maintenance personnel must fully understand and know how to use, and recognize the limitations of, the test equipment, personal computers, and any associated relay configuration and evaluation software.



Key Human Performance Point

An area of training that should not be overlooked involves test equipment and personal computers. Protective relay test sets are very specialized equipment. Considerable knowledge is required to operate them correctly. Maintenance personnel must fully understand and know how to use, and recognize the limitations of, the test equipment, personal computers, and any associated relay configuration and evaluation software.

9.7 Performance Trending

Many methods of measuring the performance of relay systems have been offered. Some of these methods can be quite involved because they require resources to maintain and evaluate performance on a continuous basis. A simplistic approach to performance trending will often yield information that is as useful as the information that results from detailed analysis.



Key O&M Cost Point

A simplistic approach to performance trending will often yield information that is as useful as the information that results from detailed analysis.

The simplistic approach looks at an event when it occurs to see if the protection function operated correctly. If it is correct, the event can be defined as a correct operation. Misoperations can be broken into subclasses. When a misoperation occurs, the cause of the event is assigned to a subclassification. Over a period of time, the total operations can be compared to the correct and incorrect operations to determine the performance of the protection equipment. Furthermore, misoperations and the subclassifications can help identify areas that may need more maintenance attention.

Another consideration for trending would be the relay application and design. These may vary from one relay installation to another, so any differences between relay types and schemes should be considered separately when trending.

The following factors should be considered when developing a performance trending tool:

- The definition of a correct and incorrect event
- Misoperation subclassifications
- Abnormal system condition influences
- Multiple operations during one event
- Human error
- The level of tripping (none, partial, or overtrip)
- Performance calculation formulas

For routine maintenance, records are normally maintained that can also be beneficial in the evaluation of the relay protection performance. One method is to use the as-found and as-left records for periodic tests and to evaluate any changes from one test interval to another. If major differences are found, it may be a signal that additional maintenance is required. If no changes are apparent, it could be an indicator that less or no maintenance is required.

9.8 Reliability-Centered Maintenance (RCM)

Reliability-centered maintenance (RCM) is a program using a systematic methodology for evaluating and implementing preventive maintenance programs. RCM was developed by the commercial air transport industry in the late 1960s as a means to more efficiently allocate maintenance activities as the size and complexity of the aircraft increased. RCM can be an effective tool for evaluating preventive maintenance programs because it concentrates on system functions, critical components, and dominant failure modes rather than addressing every component in the plant.

Today's need for economic efficiency, reliability, and minimal outage downtime requires that preventive maintenance be implemented based on the most critical factors including mean time between repairs and failure rates. Because of the variations of considered factors, RCM studies may be performed differently from one company to another. Off-the-shelf software products

have been developed to help implement RCM analysis, but they may not allow the user to modify the program as it evolves over time. New software programs are currently being introduced that are more flexible.

Reliability-centered maintenance evaluation should include the following:

- Failure mode and effects analysis
- Critical failure analysis
- Root cause analysis
- Mean time between repair
- Spare parts strategy
- Maintenance plan

Unlike conventional relays, numerical relays have no moving parts or mechanical components that can fail. Numerical relay settings are software-driven, so there are no component drift issues to consider. The focus of the RCM programs on numerical relays should shift from the components of the relay to the binary input and output operation connected from the relay to the external equipment. Another area to consider is the relay firmware changes that can take place over time. Some changes may identify unique protection problems that were undetected in earlier version devices.

Part of the predictive maintenance plan should be a database that tracks each relay's firmware and hardware version numbers to identify problems with batch manufacturing and to verify that the proper firmware is in all devices. There should also be a strategy in place with relay manufacturers for identifying known problems as well as whether a change from one version of firmware to a newer version is required.

Relay technicians should verify that they always have the latest version of relay vendor-supplied software.

Maintenance should be accelerated if the relay is not supplying metering and status data to a SCADA system because it will be more difficult to know whether the relay is operating properly.

All relay self-check contacts should be wired into a SCADA system or local annunciator for immediate notification. These contacts may also be wired into other relays to enable backup protection in the case of a primary relay failure or to adjust setting groups on backup relays.

Communication channels that carry protective trip signals between relays must also be monitored and maintained. Many relays provide the ability for SCADA to remotely monitor the error rates on these channels. Many relays also enable backup elements if primary relay elements are lost to channel failures (a line differential relay may enable distance and directional overcurrent elements if the fiber channel to the differential relay on the other side of the line is lost).

10

PROTECTIVE RELAY FAILURE MODES

10.1 Failure Mechanisms

10.1.1 Electrical Stresses

Numerical relays have come a long way in the design of the power supplies. Analog electronic relays used switch-mode power supplies. This type of design was not very robust and could be damaged if an incorrect voltage was applied to the device. Modern numerical relays have more robust power supplies. Large voltage ranges from AC to DC can be applied to the same relay.

Care must be taken, however, to ensure that the binary inputs are subjected to correct voltage. Some relays provide self-wetting supply for the binary inputs. More robust relays can accept from 300VDC or 125VAC power to the binary inputs. The binary output on numerical relays can be destroyed quite easily. The most common problem occurs where the relay contact is directly connected to the circuit breaker (CB) trip coil. There should always be CB auxiliary contacts in series with the trip coil and the relay trip contacts. The purpose of the CB auxiliary contacts is to break the electrical circuit. The CB auxiliary contacts have enough traveling distance to quench the arc created by the back EMF of the trip coil.

The relay contact must remain closed until the breaker auxiliary contacts opened the circuit. If the relay contact resets too quickly after a trip, it must open the DC circuit. This contact does not have enough traveling distance to do this. An arc will set up across the contacts and destroy the output contact. Suppliers of numerical relays have, however, built in secure reset times to ensure that this problem does not occur. If the user builds his or her own tripping logic in a numerical relay, it must be ensured that there is a reset delay of at least 500 milliseconds for every trip command issued.

If a numerical relay is applied within the product's specified voltage parameters, the user will have at least 20 years of trouble-free operation.

10.1.2 Mechanical Stresses

Mechanical stresses are greatly reduced in numerical relays as compared to mechanical induction disk relays. When examining the relay's structural design considerations for the electromechanical operating mechanism, several properties become obvious. Electromagnetic attraction is found in hinged-armature and plunger-type relays. Electromagnetic induction is found in disk/rotor and cup-type relays. Pneumatic relays are fluid-actuated. Thermal acting bimetal strip relays are another category of relay. All of these relays have moving parts that

numerical protection relays do not have. Aside from the wear of components, the problem with moving parts is that they have a larger factor for error than a digital processor on a printed circuit board. The resulting failure may result in spurious relay actuations causing circuit breaker trips induced by relay chatter. Seismic stresses from earthquake activity are a factor that will impede a relay's performance and result in spurious relay actuations. These actuations are typically caused by the opening or closing of the relay contacts due to the vibratory input of the earthquake. The most significant design basis event for electromechanical protective relays is the design basis seismic event. Few relays will be exposed to harsh environments arising from design basis reactor accidents because relays are normally located in mild environments in the plant and are not exposed to steam line breaks or high radiation.

A protective relay's capability to withstand a seismic event does not appear to change with age. The most significant expected operation is momentary contact chatter for a deenergized relay. Structural failure of relay components or electrical failure is not expected. Relays are not damaged by momentary chatter; however, severe contact chatter can result in a trip signal or inadvertent system initiation that may require operator action to correct.

EPRI's publications *Seismic Ruggedness of Relays* (N-7147-S) and *Procedure for Evaluating Nuclear Power Plant Relay Seismic Functionality* (N-7148-S) provide detailed information regarding the ability of protective relays to withstand seismic events and high-frequency vibration. Although some protective relays used in nuclear plants may be susceptible to seismic events or vibration, the resolution of NRC Unresolved Safety Issue (USI) A-46, "Seismic Qualification of Equipment in Operating Nuclear Plants," should confirm the operability of relays for use at each nuclear plant.

10.1.3 Thermal Stresses

Thermal stresses caused by climatic temperature variations affect numerical relays less than electromechanical relays. ANSI/IEEE standards define the temperature threshold for North America. Protective relays in normal condition receive a continuous low level of current. Certain relay types (such as distance relays) may experience significantly greater levels of operating current, especially when activated. A relay that has LED targets and multiple contacts to operate will have greater requirements for current flow. Long-term energization of the relay coil results in IR coil heating and stresses to all age-susceptible components in the relay. The effect on the coil and other nonmetallic materials is material degradation caused by thermally accelerated chemical reactions.



Key Technical Point

Climatic temperature variations affect numerical relays less than electromechanical relays.

Relays located in plant areas with elevated ambient temperatures are also subject to material degradation by this thermal aging process. Also, the temperature inside switchgear and panels may be significantly greater than the room ambient temperature. While the room temperature

may be in the range of 21–27°C (70–80°F), the internal temperature inside the panels may be 20–40°F higher. Elevated temperatures of this magnitude will accelerate the deterioration of the relay components, resulting in premature failure.

Sometimes, in critical locations, both the ambient temperature and humidity are controlled by a thermostat and a humidistat. They may be mounted in a relay control cabinet with the two control devices mounted in this control cabinet. The room where the cabinets are located may be climatically controlled with separate temperature requirements. Some manufacturers have a temperature rating of 85°C (185°F) for their protective relays. ANSI/IEEE specifies temperature ratings up to 70°C (158°F) and manufacturers follow ANSI/IEEE standards rigorously for the North American market. On the other hand, IEC specifies a temperature range of -40°C to +85°C/-40°F to 185°F (with reference to IEC 60068-2-1 and IEC 60068-2-2).

Per IEC 60068-2-1, the range is the following:

- -20°C to +85°C (-4°F to 185°F) for 16 hours

Other standards specify temperature ranges as follows:

- -20°C to +70°C (-4°F to 158°F) for 96 hours – derived from the British Standard
- -5°C to +55°C (23°F to 131°F) – IEC 60255-6

In conclusion, with reference to an 85°C (185°F) operating requirement, some manufacturers can meet this requirement within the parameters described by IEC 60068.

At 55°C (131°F) the legibility of the LCD display degrades. Unless the device uses special high temperature LCD displays, this is an issue all relay manufacturers must address.

10.1.4 Environmental Stresses

Environmental stresses impose a risk of relay failure. The environmental stresses that can contribute to degradation of relays are humidity, dirt, dust, oxidation, and chemical contaminants. Humidity can cause material degradation and oxidization (rusting) and can even contribute to short circuits or arcing if sufficient condensation occurs on live electrical paths. Environmental stresses from water infiltration (from rain or via forced spray from fire extinguishing equipment) can cause relay failure.

In electrometrical relays, dust and dirt can increase friction on moving parts and accelerate wear of precision relay components. Chemical contaminants may cause premature breakdown of relay materials as well as contribute to oxidation of contacts. Some manufacturers provide the option of a conformal coating on the printed circuit boards of numerical relays to allow them to survive the effects of salt air or chemical contaminants. In subtropical locations, an antifungal coating can be applied to the relay boards. The term tropicalized is used for this application.

Most relays used in nuclear plants are equipped with a dustproof case, which helps reduce the rate of deterioration caused by environmental stresses. Classification for relay case construction falls under international protection under IEC 60529. Some manufacturers supply different

classifications for the front and back of the case (for example, IP 51 classification for the front and IP 50 for the back). The rear terminals can also be covered with a protection cap, but this is more for human safety than environmental stresses. Also, IEEE C37.105-1987, *IEEE Standard for Qualifying Class 1E Protective Relays and Auxiliaries for Nuclear Power Generating Stations*, states that the following aging mechanisms are considered to be relatively insignificant based on operating experience:

- Humidity: Provided that the protective relay and auxiliary device enclosure internal air temperatures exceed surrounding air temperatures by 5°C (41°F) minimum.
- Contamination: Based on the expected application in nuclear power plants where ambient air quality is controlled to habitable levels.
- Altitude: Below 5000 ft (1524 m) as atmospheric conditions in high altitudes reduce the insulation levels and a derating factor is used. This is defined in ANSI/IEEE C37.30.
- Vibration: No evidence of sensitivity to normal in-plant vibration levels, although seismic activity poses additional concerns.

10.2 Failure Modes

The high reliability of numerical relays and the lack of an industry-wide failure database complicate analysis of relay failure modes. Because of the importance of the topic, several observations can be made that will be of value to the reader. These observations are presented in the following subsections as hardware failures and operational failures.

10.2.1 Hardware Failures

10.2.1.1 Power Supply

Of all potential failure modes, the numerical relay power supply represents a single point of failure. Fail-safe alarm contacts and loss of SCADA communications provide immediate indication of power supply failures, allowing corrective action to be initiated quickly.

10.2.1.2 Output Contacts

Most output contact failures occur when attempting to break heavy currents. To avoid this type of failure, care should be taken to ensure that trip outputs are latched until after the circuit breaker trip coil has been removed. Minimum trip duration timers and output latches are common methods used to prevent output contacts from breaking trip coil currents.

10.2.2 Operational Failures

Operational failure modes include a failure to operate when called upon and improper trip outputs issued during non-trip conditions. As previously discussed, information allowing general

statements regarding failure mode tendencies is not readily available. This information is important especially in the design of redundant schemes for critical systems.

Operational failures of numerical relays are often caused by human error; however, errors in protection algorithms have been experienced. Algorithm errors are usually not detected by relay self diagnostics, but rather are found by an undesired trip or a failure to trip for an internal fault. Firmware updates are often the corrective action taken to repair algorithm errors. Revised firmware is downloaded into the memory of the numerical relay by connecting locally with a personal computer. While technically possible, remote firmware downloads via modem are not recommended. Interruptions of the firmware download to the relay can cause catastrophic failures in some instances. Care should be exercised to ensure that the firmware download is not interrupted by loss of relay power supply, loss of PC power supply, or opening of the communications path.

11

DIGITAL RELAY SELF DIAGNOSTICS

The issue of checking self diagnostics is one that deserves attention. Multifunctional relays perform a valuable function—they consolidate protection functions (and in some instances controls) and reduce the cost and complexity of the overall application. Their contribution to this goal is only as good as their reliability. It is important to understand what the digital relays offer in order to plan your maintenance functions.



Key O&M Cost Point

Multifunctional relays perform a valuable function—they consolidate protection functions (and in some instances controls) and reduce the cost and complexity of the overall application.

Self monitoring is much more than the function of testing and monitoring the A/D converter, software, memory, and hardware. It is the first step in the self-monitoring process and it is also a test to make sure that everything in and about the relay installation is correct. This means that these relays have the intelligence to catch mistakes such as those in the following list:

- Loose wires or damaged analog connections (CT and PT circuits)
- Connection errors
- Failing PTs or CTs
- Failing circuit board (that is, something is physically or electrically wrong with the board)

Setting errors (can be detected and prevented by plausibility checks performed by relay management software)



Key Human Performance Point

Self monitoring is much more than the function of testing and monitoring the A/D converter, software, memory, and hardware. It is the first step in the self-monitoring process and it is also a test to make sure that everything in and about the relay installation is correct.

11.1 Internal Diagnostics

11.1.1 Auxiliary and Reference Voltages

The processor voltage is monitored, and if the voltage decreases below the minimum value, the device is removed from operation. When the voltage returns, the system processor is restarted. Removal of or switching off the supply voltage removes the device from operation and a message is immediately generated by a relay dead contact. Brief voltage interruptions of less than 50–100 ms should not disturb the readiness of the relay. The processor monitors the offset and reference voltage of the AD (analog-digital) converter. The protection is normally blocked if the voltages deviate outside an allowable range and lengthy deviations are normally reported in an event report.

11.1.2 Buffer Battery

The buffer battery, which ensures that the operation of the internal clock and the storage of information counters and messages, is periodically checked for charging status if the auxiliary voltage fails. If the battery voltage is less than an allowed minimum voltage, then a *failed battery* message is issued.

11.1.3 Memory Components

The working memory (RAM) is tested when the system is started up. If a failure occurs, the starting sequence is interrupted and an error message will be produced. During operation, the memory is checked using its check-sum function. For the program memory, the cross-sum is calculated periodically and compared to the stored program cross-sum.

11.1.4 Sampling

Sampling and the synchronization between the internal buffer components are constantly monitored. If any deviations cannot be removed by renewed synchronization, the system processor is normally restarted.

11.1.5 Software Monitoring

A time monitor is typically provided in the hardware (hardware watchdog) that runs upon failure of the processor or an internal program. This hardware watchdog will issue a complete restart of the processor system when a problem is detected. An additional software watchdog normally ensures that failures during the processing of programs are also discovered. This will also initiate a restart of the system processor. If a failure is not cleared by the processor restart, an additional restart will be attempted. After a number unsuccessful restarts within a time window, the relay will automatically remove itself from service and an error message will be issued via a display message or LED.

11.2 External Source Diagnostics

A digital relay can provide a diagnosis of its own internal hardware and software and can also monitor the connected system. Digital relays can monitor the health of the current transformers and voltage transformers. The relays will typically calculate the plausibility of the AC quantities under healthy operating and system fault conditions. For example, the digital relays will calculate the symmetry of the currents and voltages. Additional features provided by digital relays may include VT fuse-fail detection, current transformer saturation, CPT transients, and circuit breaker trip coil monitoring.

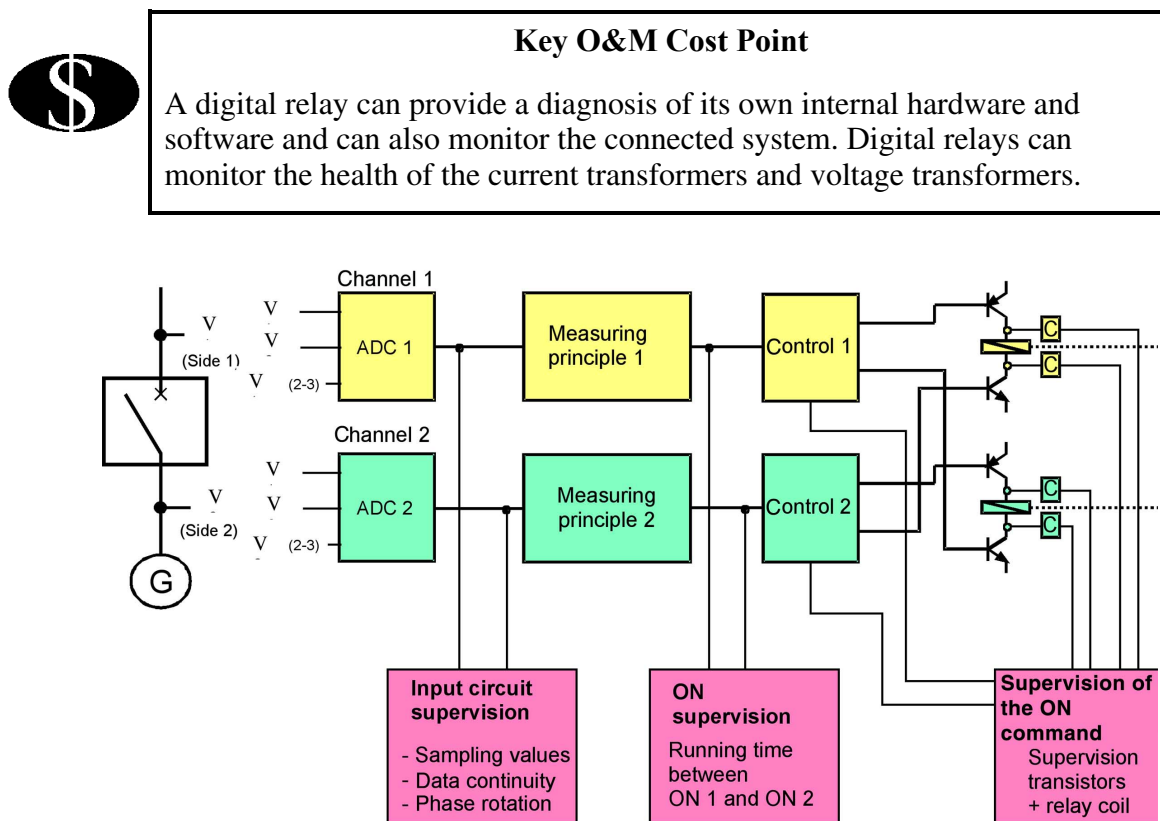


Figure 11-1
External Monitoring of a Typical Synchronizing Relay

Figure 11-1 shows the external monitoring functionality of a typical synchronizing relay. It can be seen from this diagram that the relay monitors the connected system voltages for correct rotation. This is a good example of external monitoring.

These external features can be used to inhibit the relay from operating if it detects one of the previously mentioned conditions. Therefore, the digital relay provides additional security to the protection system.

It is worth the effort to look at the monitoring features that are provided with every digital relay. However, the user must not be blinded by all of the external monitoring features. The most important function remains as the internal monitoring feature common to each and every digital relay.

11.3 Failure Indications/Contacts

Failure indications can be produced by digital relays using a number of methods. It can be provided by a dry (normally closed) contact, an LED, device display, or the system/SCADA interface.

The most important indication is the dry relay fail contact. This contact will open after the relay is powered up and the watchdog programs detect no failures in the relay. The contact will close when the relay watchdog programs detect a failure or if the power is lost to the relay. The contact is normally wired out in parallel with other relay fail contacts in a protection scheme to provide a general relay fail alarm.

Digital relays also have other means to indicate a relay failure. The most common is to have an LED on the front of the relay that will indicate relay failure. It is also beneficial if the relay has an LED indicating that the relay is fully functional.

Digital relays can also provide failure information from the relay front display. A digital relay can display test messages of a failure. The type of failure can be described in more detail. A relay can, for example, indicate that it detected a fault on a certain IO board, informing the user what component needs to be replaced.

Additionally, it is also possible to program the relay to show a text message informing the operator that a certain telephone number must be called in the event of a trip or a relay failure.

The digital relay can and will keep the operator informed of the health of the relay and the connected system through various means.

12

OPERATIONAL AND FAULT DATA INFORMATION

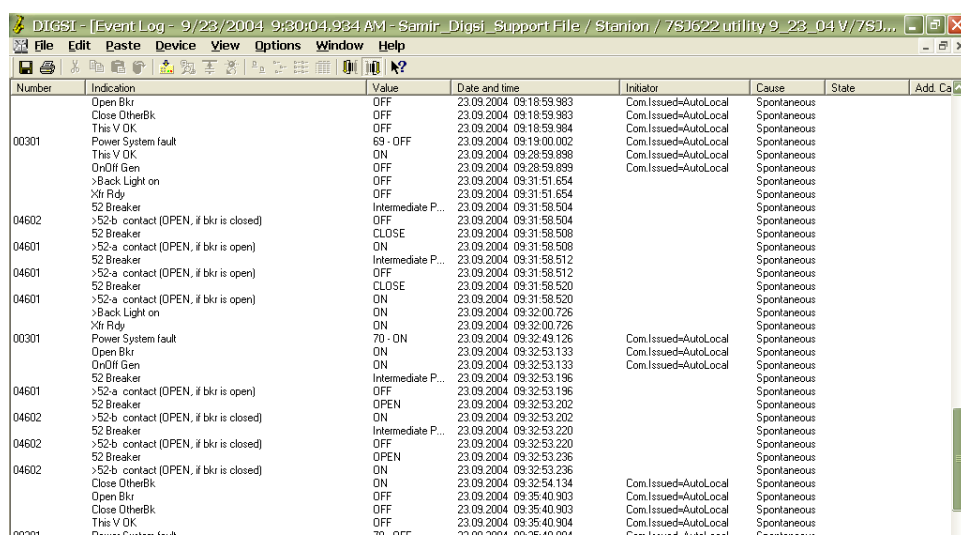
12.1 Annunciations

12.1.1 Event Logs

The event log is a collection of power system operational status and the relay's response to that status. These events may or may not be related to the power system fault. The events generated by power system fault conditions are recorded by the relay together with the relay responses such as pickup or dropout of the protective elements. The events triggered by the nonfault conditions are equally important because they allow identification of the system operational status. The typical nonfault events are switching operations, interlocking operations, and control operations.

Event logs should be large enough to store an adequate number of events for an engineer to track the system performance over a period of time. Event logs are beneficial in analyzing the fault and/or operational behavior of the power system. See Figure 12-1 for a sample event log.

In some relays, the information to be recorded in the event log is programmable. The power system fault data and other events are stored in a nonvolatile memory. The relay keeps the information until the event log buffer is full. Upon achieving the maximum number of events, the first-in, first-out buffer erases the oldest information to allow storage of the most recent event.



Number	Indication	Value	Date and time	Initiator	Cause	State	Add Ca
	Open Bkr	OFF	23.09.2004 09:18:59.983	Com.Issued=AutoLocal	Spontaneous		
	Close OtherBkr	OFF	23.09.2004 09:18:59.983	Com.Issued=AutoLocal	Spontaneous		
	This V OK	OFF	23.09.2004 09:18:59.984	Com.Issued=AutoLocal	Spontaneous		
00301	Power System fault	69 - OFF	23.09.2004 09:19:00.002	Com.Issued=AutoLocal	Spontaneous		
	This V OK	ON	23.09.2004 09:28:59.898	Com.Issued=AutoLocal	Spontaneous		
	OnOff Gen	OFF	23.09.2004 09:28:59.899	Com.Issued=AutoLocal	Spontaneous		
	>Back Light on	OFF	23.09.2004 09:31:51.654		Spontaneous		
	Xtr Rdy	OFF	23.09.2004 09:31:51.654		Spontaneous		
	52 Breaker	Intermediate P...	23.09.2004 09:31:58.504		Spontaneous		
04602	>52-b contact (OPEN, if bkr is closed)	OFF	23.09.2004 09:31:58.504		Spontaneous		
	52 Breaker	CLOSE	23.09.2004 09:31:58.508		Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	ON	23.09.2004 09:31:58.508		Spontaneous		
	52 Breaker	Intermediate P...	23.09.2004 09:31:58.512		Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	OFF	23.09.2004 09:31:58.512		Spontaneous		
	52 Breaker	CLOSE	23.09.2004 09:31:58.520		Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	ON	23.09.2004 09:31:58.520		Spontaneous		
	>Back Light on	ON	23.09.2004 09:32:00.726		Spontaneous		
	Xtr Rdy	ON	23.09.2004 09:32:00.726		Spontaneous		
00301	Power System fault	70 - ON	23.09.2004 09:32:49.126	Com.Issued=AutoLocal	Spontaneous		
	Open Bkr	ON	23.09.2004 09:32:53.133	Com.Issued=AutoLocal	Spontaneous		
	OnOff Gen	ON	23.09.2004 09:32:53.133	Com.Issued=AutoLocal	Spontaneous		
	52 Breaker	Intermediate P...	23.09.2004 09:32:53.196		Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	OFF	23.09.2004 09:32:53.196		Spontaneous		
	52 Breaker	OPEN	23.09.2004 09:32:53.202		Spontaneous		
04602	>52-b contact (OPEN, if bkr is closed)	ON	23.09.2004 09:32:53.202		Spontaneous		
	52 Breaker	Intermediate P...	23.09.2004 09:32:53.220		Spontaneous		
04602	>52-b contact (OPEN, if bkr is closed)	OFF	23.09.2004 09:32:53.220		Spontaneous		
	52 Breaker	OPEN	23.09.2004 09:32:53.236		Spontaneous		
04602	>52-b contact (OPEN, if bkr is closed)	ON	23.09.2004 09:32:54.134	Com.Issued=AutoLocal	Spontaneous		
	Close OtherBkr	OFF	23.09.2004 09:35:40.903	Com.Issued=AutoLocal	Spontaneous		
	Open Bkr	OFF	23.09.2004 09:35:40.903	Com.Issued=AutoLocal	Spontaneous		
	Close OtherBkr	OFF	23.09.2004 09:35:40.904	Com.Issued=AutoLocal	Spontaneous		
	This V OK	OFF	23.09.2004 09:35:40.904	Com.Issued=AutoLocal	Spontaneous		
	Power System fault	70 - OFF	23.09.2004 09:35:40.904	Com.Issued=AutoLocal	Spontaneous		

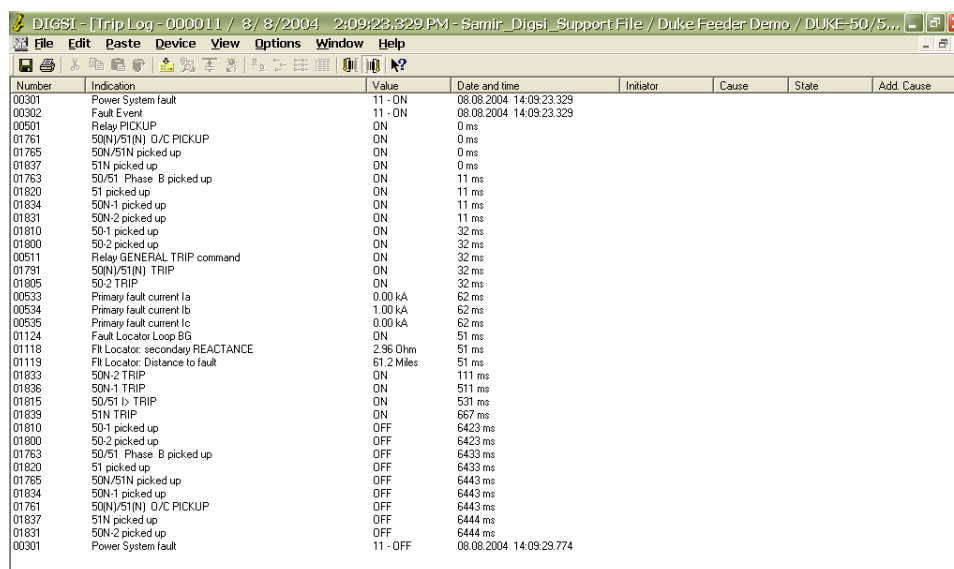
Figure 12-1
Sample Event Log

12.1.2 Trip Logs

Unlike event logs, the trip logs are not created for a nonsystem fault. As its name suggests, the trip log records only the information of power system fault conditions.

The trip log is important in analyzing the fault and the sequence of the fault. The trip log records the power system abnormal condition as seen by the relay. This can be particularly helpful in determining the fault inception and the phase involved in the fault. For example, the trip log is useful when a single line-to-ground fault transitions into a line-to-line-to-ground fault. The trip log also detects the value of the fault current and the voltage at the instant of the trip. Having detected the current and voltage at the time of the trip, the relay can also calculate the distance to the fault.

The trip logs are dedicated to each fault rather than a combination of multiple events. This makes it easier to analyze the fault by date and time of the occurrence. Figure 12-2 shows a sample trip log.



Number	Indication	Value	Date and time	Initiator	Cause	State	Add. Cause
00301	Power System fault	11 - ON	08.08.2004 14:09:23.329				
00302	Fault Event	11 - ON	08.08.2004 14:09:23.329				
00501	Relay PICKUP	ON	0 ms				
01761	50(N)/51(N) O/C PICKUP	ON	0 ms				
01765	50N/51N picked up	ON	0 ms				
01837	51N picked up	ON	0 ms				
01763	50/51 Phase B picked up	ON	11 ms				
01820	51 picked up	ON	11 ms				
01834	50N-1 picked up	ON	11 ms				
01831	50N-2 picked up	ON	11 ms				
01810	50-1 picked up	ON	32 ms				
01800	50-2 picked up	ON	32 ms				
00511	Relay GENERAL TRIP command	ON	32 ms				
01791	50(N)/51(N) TRIP	ON	32 ms				
01805	50-2 TRIP	ON	32 ms				
00533	Primary fault current Ia	0.00 kA	62 ms				
00534	Primary fault current Ib	1.00 kA	62 ms				
00535	Primary fault current Ic	0.00 kA	62 ms				
01124	Fault Locator Loop BG	ON	51 ms				
01118	Flt Locator: secondary REACTANCE	2.96 Ohm	51 ms				
01119	Flt Locator: Distance to fault	61.2 Miles	51 ms				
01833	50N-2 TRIP	ON	111 ms				
01836	50N-1 TRIP	ON	511 ms				
01815	50/51 to TRIP	ON	531 ms				
01839	51N TRIP	ON	667 ms				
01810	50-1 picked up	OFF	6423 ms				
01800	50-2 picked up	OFF	6423 ms				
01763	50/51 Phase B picked up	OFF	6433 ms				
01820	51 picked up	OFF	6433 ms				
01765	50N/51N picked up	OFF	6443 ms				
01834	50N-1 picked up	OFF	6443 ms				
01761	50(N)/51(N) O/C PICKUP	OFF	6443 ms				
01837	51N picked up	OFF	6444 ms				
01831	50N-2 picked up	OFF	6444 ms				
00301	Power System fault	11 - OFF	08.08.2004 14:09:29.774				

Figure 12-2
Sample Trip Log

12.1.3 Spontaneous Annunciations

Unlike event and trip logs, the spontaneous annunciations are signals either asserting or de-asserting in the relay. As the name suggests, they are spontaneous—the user is not required to program these annunciations. Spontaneous annunciations are a true assessment of the power system, its components, switching devices, relay inputs and outputs, protective functions, interlocking functions, and control functions (see Figure 12-3).

These annunciations are very useful by providing insights about the relay elements. Depending upon the digital inputs, analog inputs and other system data fed to the relay are eventually processed. The relay records all of these processes in the spontaneous annunciations.

The screenshot shows a software window titled "DIGSI - Spontaneous Annunciation - 8/ 7/2004 2:23:36,069 PM - Samir_Digsi_Support File / Duke Feeder Demo / DUK...". The window contains a table with the following columns: Number, Indication, Value, Date and time, Initiator, Cause, State, and Add. Ca. The table lists various relay events such as "Reset LED", "74TC Trip circuit supervision is ACTIVE", "99-2 Disc", and "Residual Endurance Phase A".

Number	Indication	Value	Date and time	Initiator	Cause	State	Add. Ca.
06863	Reset LED	ON	07.08.2004 11:14:51.682	Command Issue...	Command E...		
	74TC Trip circuit supervision is ACTIVE	ON	07.08.2004 11:14:52.473	Com.Issued=Aut...	Spontaneous		
00852	Reset LED	OFF	07.08.2004 11:14:52.803	Com.Issued=Aut...	Spontaneous		
	Ia Max	0.0 A	07.08.2004 11:14:52.878	Com.Issued=Aut...	Spontaneous		
06865	74TC Failure Trip Circuit	ON	07.08.2004 11:14:53.673	Com.Issued=Aut...	Spontaneous		
00854	Ib Max	0.0 A	07.08.2004 11:14:55.878	Com.Issued=Aut...	Spontaneous		
00856	Ic Max	0.0 A	07.08.2004 11:14:55.878	Com.Issued=Aut...	Spontaneous		
	99-2 Disc	CLOSE	07.08.2004 11:14:56.998	Command Issue...	Control Issued		
	ON/OFF (SP)	OFF	07.08.2004 11:14:57.422	Command Issue...	Intermediate...		
	99-2 Disc	Intermediate Position	07.08.2004 11:14:57.422	Command Issue...	Spontaneous		
	ON/OFF (SP)	ON	07.08.2004 11:14:57.428	Command Issue...	Feedback P...		
	99-2 Disc	CLOSE	07.08.2004 11:14:57.428	Command Issue...	Command E...		
	99-2 Disc	CLOSE	07.08.2004 11:15:02.472	Command Issue...	Control Issued		
	99-1 Disc	CLOSE	07.08.2004 11:15:06.612	Command Issue...	Spontaneous		
	>CB ready Spring is charged	OFF	07.08.2004 11:15:07.040	Command Issue...	Spontaneous		
	>CB waiting for Spring charged	ON	07.08.2004 11:15:07.040	Command Issue...	Spontaneous		
	ON/OFF (SP)	OFF	07.08.2004 11:15:07.040	Command Issue...	Intermediate...		
	99-1 Disc	Intermediate Position	07.08.2004 11:15:07.040	Command Issue...	Spontaneous		
	>Door closed	ON	07.08.2004 11:15:07.048	Command Issue...	Spontaneous		
	>Cabinet door open	OFF	07.08.2004 11:15:07.048	Command Issue...	Spontaneous		
	ON/OFF (SP)	ON	07.08.2004 11:15:07.048	Command Issue...	Feedback P...		
	99-1 Disc	CLOSE	07.08.2004 11:15:12.076	Command Issue...	Command E...		
	99-1 Disc	CLOSE	07.08.2004 11:15:12.932	Com.Issued=Aut...	Spontaneous		
170.2025.01	25 Monitoring time exceeded	ON	07.08.2004 11:15:12.932	Com.Issued=Aut...	Spontaneous		
170.2103.01	25 CLOSE command is BLOCKED	ON	07.08.2004 11:15:13.536	Com.Issued=Aut...	Spontaneous		
170.2007.01	25 Sync. Measuring request of Control	ON	07.08.2004 11:15:22.278	Com.Issued=Aut...	Spontaneous		
00873	V neutral Max	0 kV	07.08.2004 11:15:24.948	Command Issue...	Control Reje...		SW: 1 t
04602	>52-b contact (OPEN, if bkr is closed)	CLOSE	07.08.2004 11:15:59.928	Command Issue...	Spontaneous		
	52-b Bkr	OFF	07.08.2004 11:15:59.928	Command Issue...	Spontaneous		
	52-b Bkr	Intermediate Position	07.08.2004 11:15:59.928	Command Issue...	Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	OFF	07.08.2004 11:15:59.928	Command Issue...	Spontaneous		
	52-a Bkr	ON	07.08.2004 11:15:59.935	Command Issue...	Spontaneous		
	52-b Bkr	CLOSE	07.08.2004 11:15:59.935	Command Issue...	Spontaneous		
04601	>52-a contact (OPEN, if bkr is open)	OPEN	07.08.2004 11:16:16.448	Command Issue...	Control Reje...		SW: 1 t
	52-a Bkr	OFF	07.08.2004 11:17:13.178	Command Issue...	Spontaneous		
04602	>52-b contact (OPEN, if bkr is closed)	Intermediate Position	07.08.2004 11:17:13.178	Command Issue...	Spontaneous		
	52-b Bkr	ON	07.08.2004 11:17:13.185	Command Issue...	Spontaneous		
	52-b Bkr	OPEN	07.08.2004 11:17:13.185	Command Issue...	Spontaneous		
	52-b Bkr	ON	07.08.2004 11:17:13.185	Command Issue...	Spontaneous		
16006	Residual Endurance Phase A	9999	07.08.2004 11:17:13.294	Com.Issued=Aut...	Spontaneous		
16011	Number of mechanical Trips Phase A	1	07.08.2004 11:17:13.294	Com.Issued=Aut...	Spontaneous		

Figure 12-3
Spontaneous Annunciations

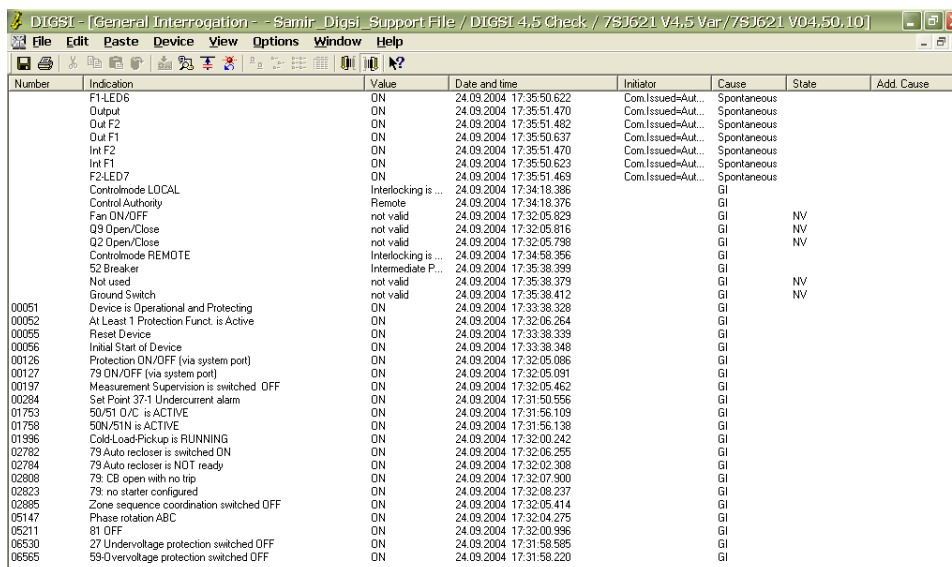
12.1.4 General Device Interrogation

The relay allows the general interrogation of its inputs, outputs, protection, control, and interlocking. It shows the current status of these components. The general interrogation lists the items that exist in the relay at the time of interrogation.

The general interrogation (see Figure 12-4) is different from the event log, trip log, and spontaneous annunciation in a sense that it reports only the active elements or active components at that instance of interrogation. The event log and trip log are reports for past occurrences. The spontaneous annunciations are transient and thus may show that the output of the relay is high when it may have occurred.

In a way, the general interrogation is the only way to find out about the current operating status of the relay.

Operational and Fault Data Information



Number	Indication	Value	Date and time	Initiator	Cause	State	Add. Cause
	F1-LED6	ON	24.09.2004 17:35:50.622	Com.Issued=Aut...	Spontaneous		
	Output	ON	24.09.2004 17:35:51.470	Com.Issued=Aut...	Spontaneous		
	Out F2	ON	24.09.2004 17:35:51.482	Com.Issued=Aut...	Spontaneous		
	Out F1	ON	24.09.2004 17:35:50.637	Com.Issued=Aut...	Spontaneous		
	Int F2	ON	24.09.2004 17:35:51.470	Com.Issued=Aut...	Spontaneous		
	Int F1	ON	24.09.2004 17:35:50.623	Com.Issued=Aut...	Spontaneous		
	F2-LED7	ON	24.09.2004 17:35:51.469	Com.Issued=Aut...	Spontaneous		
	Controlmode LOCAL	Interlocking is ...	24.09.2004 17:34:18.386		GI		
	Control Authority	Remote	24.09.2004 17:34:18.376		GI		
	Fan ON/OFF	not valid	24.09.2004 17:32:05.829		GI	NV	
	Q3 Open/Close	not valid	24.09.2004 17:32:05.816		GI	NV	
	Q2 Open/Close	not valid	24.09.2004 17:32:05.798		GI	NV	
	Controlmode REMOTE	Interlocking is ...	24.09.2004 17:34:58.356		GI		
	52 Breaker	Intermediate P...	24.09.2004 17:35:38.399		GI		
	Not used	not valid	24.09.2004 17:35:38.379		GI	NV	
	Ground Switch	not valid	24.09.2004 17:35:38.412		GI	NV	
00051	Device is Operational and Protecting	ON	24.09.2004 17:33:38.328		GI		
00052	At Least 1 Protection Funct. is Active	ON	24.09.2004 17:32:06.264		GI		
00055	Reset Device	ON	24.09.2004 17:33:38.339		GI		
00056	Initial Start of Device	ON	24.09.2004 17:33:38.348		GI		
00126	Protection ON/OFF (via system port)	ON	24.09.2004 17:32:05.086		GI		
00127	79 ON/OFF (via system port)	ON	24.09.2004 17:32:05.091		GI		
00197	Measurement Supervision is switched OFF	ON	24.09.2004 17:32:05.462		GI		
00284	Set Point 37-1 Undercurrent alarm	ON	24.09.2004 17:31:50.556		GI		
01753	50/51 O/C is ACTIVE	ON	24.09.2004 17:31:56.109		GI		
01758	50N/51N is ACTIVE	ON	24.09.2004 17:31:56.138		GI		
01996	ColdLoad-Pickup is RUNNING	ON	24.09.2004 17:32:00.242		GI		
02782	79 Auto recloser is switched ON	ON	24.09.2004 17:32:06.255		GI		
02784	79 Auto recloser is NOT ready	ON	24.09.2004 17:32:02.308		GI		
02808	79 CB open with no trip	ON	24.09.2004 17:32:07.900		GI		
02823	79 no starter configured	ON	24.09.2004 17:32:08.237		GI		
02865	Zone sequence coordination switched OFF	ON	24.09.2004 17:32:05.414		GI		
05147	Phase rotation ABC	ON	24.09.2004 17:32:04.275		GI		
05211	81 OFF	ON	24.09.2004 17:32:00.996		GI		
06530	27 Undervoltage protection switched OFF	ON	24.09.2004 17:31:58.585		GI		
06565	59-Overvoltage protection switched OFF	ON	24.09.2004 17:31:58.220		GI		

Figure 12-4
General Device Interrogations

12.1.5 Fault Records

The fault records are the most important feature of the microprocessor relays (see Figure 12-5). The relays have a capability to trigger the fault recording even for the pre-fault conditions. The relays readily know the analog and digital input and output status so that recording the pre-fault data is easily achieved using microprocessor relays. Without microprocessor relays, the task of recording the pre-fault and post-fault data is difficult and even impossible in some cases.

With microprocessor relays, a user can specify the triggering of the fault record, the duration of the recording, and the type of recording (that is, raw data as measured by the relay or filtered data). The fault record is transmitted to a PC for analysis and can also be distributed with a universal file format. The fault record contains analog data, digital data, relay internal points, inputs, and outputs. The analog data can be displayed in waveforms; the digital data are displayed in bars. The relay keeps these fault records in nonvolatile memory so that upon loss of relay power, the fault record stays intact for future retrieval.



Key O&M Cost Point

With microprocessor relays, a user can specify the triggering of the fault record, the duration of the recording, and the type of recording (that is, raw data as measured by the relay or filtered data).

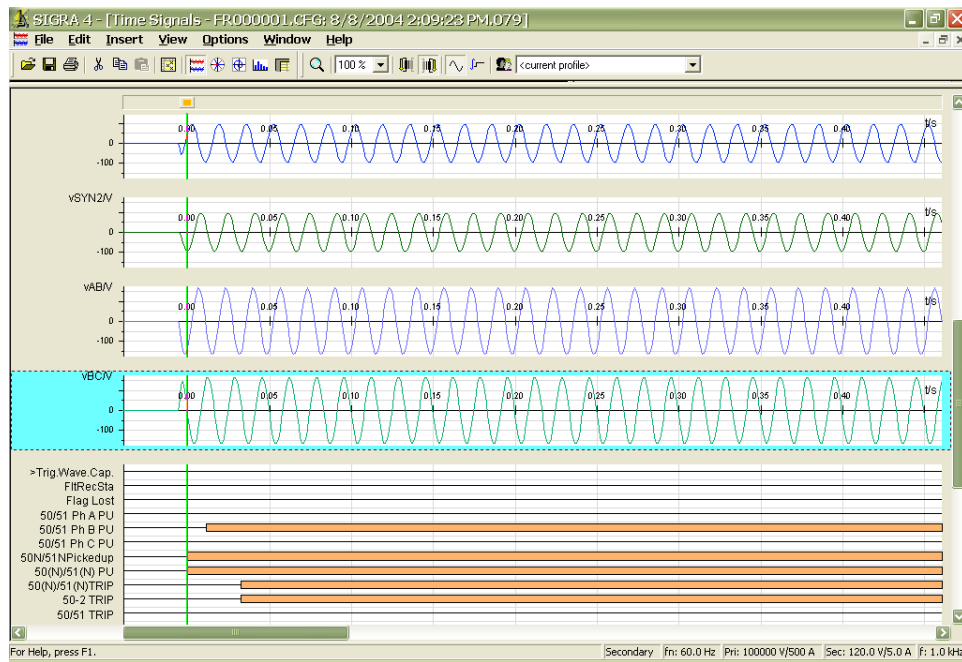


Figure 12-5
Fault Records

13

CONTROL SCHEME MONITORING

One of the most valuable features of the microprocessor relay is its ability to continuously monitor its internal subsystems and software, detect any malfunctions, and provide an alarm that allows service personnel to be dispatched. As an ever-increasing percentage of the overall protection control scheme is integrated into the relay, the possibility exists to extend the benefits of self diagnostics beyond the internal subsystems of the relay. Using binary inputs to provide the relay with information regarding the health status of the control scheme, it is possible to use microprocessor relay programmable logic control functions to detect and respond to external control scheme malfunctions.

Key O&M Cost Point



As an ever-increasing percentage of the overall protection control scheme is integrated into the relay, the possibility exists to extend the benefits of self diagnostics beyond the internal subsystems of the relay. Using binary inputs to provide the relay with information regarding the health status of the control scheme, it is possible to use microprocessor relay programmable logic control functions to detect and respond to external control scheme malfunctions.

13.1 Trip Circuit Monitoring (TCM)

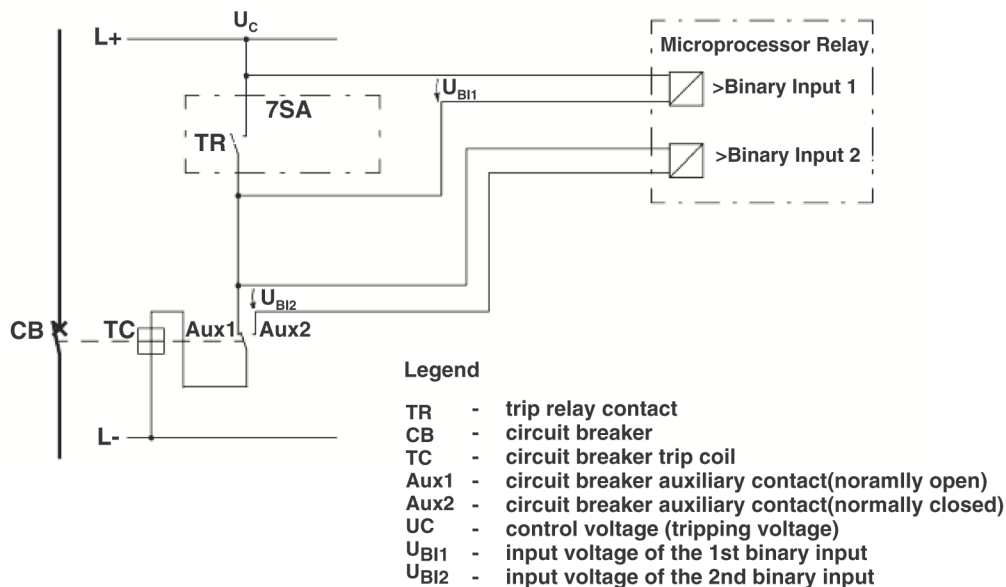
An open circuit breaker trip coil circuit is a particularly harmful single point of failure that is also not uncommon. Two different methods of trip circuit monitoring (TCM) are possible. Using the single binary input method, the integrity of the trip coil and the series resistor is possible. When a second isolated binary input is available, it is possible to improve the self diagnostics of the TCM scheme to monitor the response of the circuit breaker using breaker auxiliary contacts.

13.1.1 Dual Binary Input Method of Trip Circuit Monitoring

To implement the dual binary input method of trip circuit monitoring, one isolated binary input is connected in parallel with the associated relay trip output contact. The remaining isolated binary input is connected in parallel to a circuit breaker auxiliary contact (see Figure 13-1).

Control Scheme Monitoring

In Figure 13-1, binary input 1 (BI 1) is asserted (logic state = H) when the relay trip contact is opened and de-asserted (logic state = L) when the trip contact is closed. Binary Input 2 (BI 2) is connected to a circuit breaker “b” auxiliary contact. BI 2 is, therefore, asserted when the circuit breaker is open.



Note: The circuit breaker is shown in closed position

Figure 13-1
Dual Binary Input Method of Trip Circuit Monitoring

The circuit of Figure 13-1 results in the truth table shown in Table 13-1:

Table 13-1
Table for Dual Binary Input Method of Trip Circuit Monitoring

No.	Trip Contact	Circuit Breaker	Aux. Cont. 1	Aux. Cont. 2	BI 1	BI 2
1	Open	On	Closed	Open	H	L
2	Open	Off	Open	Closed	H	H
3	Closed	On	Closed	Open	L	L
4	Closed	Off	Open	Closed	L	H

The state in which both binary inputs are de-asserted (logic state = “L”) is possible only with intact trip circuits for a short transition period (trip relay contact closed but circuit breaker not yet open). A continuous state of this condition is possible only when the trip circuit has been interrupted, a short circuit exists in the trip circuit, a loss of battery voltage occurs, or malfunctions occur with the circuit breaker mechanism.

Figure 13-2 shows an example logic circuit to create a TCM alarm. The timer should be set for 1–2 seconds in order to prevent TCM alarms during the transitional state when a relay trip is being issued.

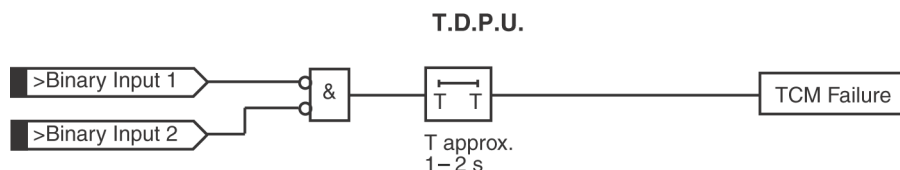
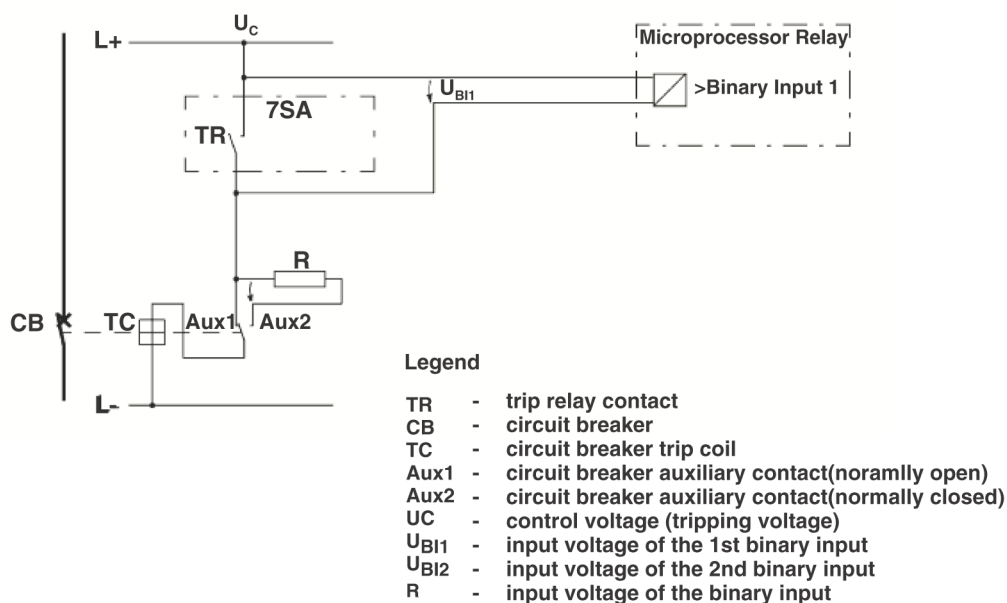


Figure 13-2
Example Logic - Dual Binary Input Method of Trip Circuit Monitoring

13.1.2 Single Binary Input Method of Trip Circuit Monitoring

For this TCM application, a single binary input is connected in parallel with the relay trip output contact, and a resistor of high ohmic value is placed in parallel with the circuit breaker auxiliary contact as shown in Figure 13-3.



Note: The circuit breaker is shown in closed position.

Figure 13-3
Single Binary Input Method of Trip Circuit Monitoring

Control Scheme Monitoring

During normal operation, the binary input is asserted (logic state = H) for both open and closed breaker conditions because the monitoring circuit is closed by either the circuit breaker auxiliary contact (circuit breaker closed) or through the bypass resistor R (circuit breaker open).

A failure of the trip circuit will cause the binary input to be continuously de-asserted. A logic timer is necessary to filter out improper TCM alarms during relay trip outputs. The TCM time delay should be set to prevent alarms for the longest anticipated trip output command.

13.2 Closed Circuit Monitoring (CCM)

While less critical than trip coil monitoring, there may be applications where a failure to close (or reclose) warrants control scheme monitoring. In such applications, the same methods described in trip coil monitoring can be used to verify the integrity of the closed circuit.

13.3 Fuse Failure Monitoring

Healthy and accurate voltage inputs are critical for impedance and voltage-controlled relay protection. Microprocessor relays have the necessary intelligence to monitor, detect, and respond to failures of the AC voltage input circuits. Failures of the voltage measuring circuit must be distinguished from voltage excursions caused by power system faults.



Key Technical Point

Microprocessor relays have the necessary intelligence to monitor, detect, and respond to failures of the AC voltage input circuits.

If a voltage failure is recognized, the distance protection and all other functions that operate on the basis of undervoltage (that is, also weak in-feed tripping) should be blocked to prevent improper tripping due to load current. Backup protection that does not rely upon healthy voltages should be available for emergency protection during loss of potential conditions.



Key Technical Point

Backup protection that does not rely upon healthy voltages should be available for emergency protection during loss of potential conditions.

13.3.1 Fuse Failure Monitoring –Three-Phase Failure

A three-phase failure of the secondary measured can be distinguished from an actual system fault by a lack of corresponding current change. For applications where line side PTs are used, a nuisance alarm during open breaker conditions is avoided by requiring a minimum amount of current to detect a pole-closed condition. A three-pole voltage failure is detected if the following conditions occur:

- All three-phase ground voltages fall below the specified minimum voltage
- The current differential in all three phases is smaller than the preset limit
- All three-phase current amplitudes are greater than the preset pole-open minimum current limit (that is, the breaker is closed)
- All three-phase current amplitudes are smaller than the three-phase minimum fault detector current

13.3.2 Fuse Failure Monitoring –Single-Phase and Phase-Phase Failure

The failure of a single potential fuse or the concurrent failure of two potential fuses will create an asymmetrical voltage input to the microprocessor relay without a corresponding current imbalance.

The asymmetry of the voltage during a non-three-phase fuse failure is detected by an increase in the zero-sequence or negative-sequence voltage. A single-phase or phase-to-phase fault is ruled out if the measured current remains sufficiently symmetrical (that is, no zero or negative-sequence current).

In ungrounded systems, the zero-sequence system quantities are not a reliable indication of a fuse failure condition. In ungrounded systems, the zero-sequence voltage should not be relied upon and negative-sequence voltage should instead be used to indicate a voltage imbalance.

A

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A.7 Principal Manufacturers

1. General Electric Company Protection & Control, 205 Great Valley Parkway Malvern, PA 19355-1337.
2. ABB Power T&D Company, Inc. Relay Division, 4300 Coral Ridge Drive, Coral Springs, FL 33065. (ABB Power T&D Company manufactures the Westinghouse line of protective relays.)
3. Siemens Power Transmission and Distribution, 7000 Siemens Road, Wendell, NC 27591.

B

GLOSSARY

The definitions provided in Appendix B were obtained from the references listed in Appendix A.

A

AC - Alternating Current.

acceptance criteria - Specified limits placed on the characteristics or performance of an item, process, or service as defined in codes, standards, or other requirement documents.

A/D converter - See **ADC**.

adaptive relaying - The ability of microprocessor relays to change the relay's protection and control characteristics as system conditions warrant.

ADC - Analogue-to-digital converter. An integrated circuit that converts instantaneous analog values into an 8 or 16 bit binary word suitable for manipulation by a microprocessor. ADC is used by numeric relays to convert incoming voltages and currents into a numeral suitable for mathematical manipulation by protection algorithms.

address - Unique identifier assigned to a microprocessor protective relay or other IED connected in a bus or ring type communication topography. The address is used to ensure that the proper device receives messages that are sent on the communications network.

alarm relay - A monitoring relay whose function is to operate an audible or visual signal to announce the occurrence of an operation or a condition needing personal attention (and which is usually provided with a signaling cancellation device).

algorithm - A step-by-step problem-solving procedure—especially an established, recursive computational procedure for solving a problem in a finite number of steps. In numeric relays, algorithms are used to implement various protection functions such as impedance measurement or time-overcurrent.

analog-to-digital converter - See **ADC**.

AND logic - Basic Boolean logic element functionally equivalent to series contacts. Both inputs to an AND gate must be logic “1” to assert the output.

Glossary

armature (of a relay) - The moving element of an electromechanical relay that contributes to the designed response of the relay and that usually has a part of the relay contact assembly associated with it.

auxiliary relay - A relay whose function is to assist another relay or control device in performing a general function by supplying supplementary actions. See **Blocking Relay**.

auxiliary relay driver - A circuit that supplies an input to an auxiliary relay.

available short-circuit current - The maximum current that the power system can deliver through a given circuit point to any negligible impedance short circuit applied at the given point or at any other point that will cause the highest current to flow through the given point.

available short-circuit test current - The maximum short-circuit current for any given setting of a test circuit that the test power source can deliver at the point of test.

B

backup protection - A form of protection that operates independently of specified components in the primary protective system. Backup protection may duplicate the primary protection and may be intended to operate only if the primary protection fails or is temporarily out of service.

balance relay - A relay that operates by comparing the magnitude of two similar input quantities.

baud rate - A measurement of communication speed expressed in bits/second. Baud rates of IED communication ports must be configured to enable successful communications with external devices.

bay controller - Devices with control and monitoring functions without protective functions. Multifunctional microprocessor protective relays with internal logic controller functions have the capability to integrate the functions of a bay controller.

bias - A shift in the signal zero point by some amount.

binary input - Optically isolated contact input buffer. The binary input is used to provide global information to microprocessor relays and is also known as a digital input.

binary output - Output contact of a microprocessor relay or other IED.

blocking - A relay function that prevents action that would otherwise be initiated by the relay system.

blocking relay - A relay whose function is to render another relay or device ineffective under specified conditions.

burden (of a relay) - Load impedance imposed by a relay on an input circuit expressed in ohms and phase angle at specified conditions.

C

calibration - The adjustment of a device to have the designed operating characteristics. Calibration may also include the subsequent marking of the positions of the adjusting means or making adjustments necessary to bring operating characteristics into substantial agreement with standardized scales or marking.

calibration error - In the operation of a device, the departure (under specified conditions) of actual performance from performance indicated by scales, dials, or other markings on the device.

calibration scale - A set of graduations marked to indicate values of quantities such as current, voltage, or time (which an automatic device can be set to operate).

case (frame) ground protection - Overcurrent relay protection used to detect current flow in the ground or earth connection of the equipment or machine. See **Current Rating (of a Relay)**.

CFC - The continuous function chart is a method of programming PLCs that has been incorporated into some microprocessor relays.

chatter blocking - The timer setting associated with a microprocessor relay's digital input used to filter a rapidly intermittent binary input. Chatter blocking is used to prevent overloading the relay with nuisance input indications.

class 1E - The safety classification of the electric equipment and systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal, or are otherwise essential in preventing significant release of radioactive material to the environment. The terms "Class 1E" and "safety-related" are used interchangeably in this report.

clearing time - The interval between the time actuating quantity in the main circuit reaches the value causing actuation of the release and the instant of final arc extinction on all poles of the primary arcing contacts.

closing relay - A form of auxiliary relay used with an electrically operated device to control the closing and opening of the closing circuit of the device so that the main closing current does not pass through the control switch or other initiating device.

com port - Communications port. The communications port is part of the I/O subsystem of a microprocessor relay or other IED. It is used to enable communications between the IED and a computer or other IED.

COMTRADE - Common Format for Transient Data Exchange. This is an industry standard format for fault records.

Glossary

confidence interval - An interval that contains the population mean to a given probability.

control display - Large graphic display included in some microprocessor relays used to represent a mimic bus and primary devices being controlled by the relay. A control display can be used to display breaker status, initiate controls, and display metering/status information.

control relay - An auxiliary relay whose function is to initiate or permit the next desired operation in a control sequence.

critical impulse (of a relay) - The maximum impulse in terms of duration and input magnitude that can be applied suddenly to a relay without causing pickup.

current-balance relay - A balance relay that operates by comparing the magnitudes of two current inputs.

current phase-balance protection - A method of protection in which an abnormal condition within the protected equipment is detected by the current unbalance between the phases of a normally balanced polyphase system.

current rating (of a relay) - The limiting current at specified frequency that may be sustained by the relay for an unlimited period without causing any of the prescribed limitations to be exceeded.

current relay - A relay that responds to current.

current transformer - An instrument transformer that is intended to have its primary winding connected in series with the conductor carrying the current to be measured.

D

DC - Direct current.

Dead Man Timer - See **Watchdog Timer**.

definite-minimum-time relay - An inverse-time relay in which the operating time becomes substantially constant at high values of input.

definite-time relay - A relay in which the operating time is substantially constant regardless of the magnitude of the input quantity.

degree of asymmetry (of a current at any time) - The ratio of the direct-current nondirectional relay so that it will not operate until the two or more phasor quantities used to actuate the controlling means (directional relay) are in a predetermined band of phase relations with a reference input. The degree of asymmetry is a component of the peak value of the symmetrical component determined from the envelope of the current wave at that time.

delayed release trip - A release with intentional delay introduced between the instant when the activating quantity reaches the release setting and the instant when the release operates.

dependability (of a relay or relay system) - The facet of reliability that relates to the degree of certainty that a relay or relay system will operate correctly.

design tests - Those tests made to determine the adequacy of a particular type, style, or model of equipment with its component parts to meet its assigned ratings and to operate satisfactorily under normal service conditions or under special conditions, if specified.

dielectric withstand-voltage tests - Tests made to determine the ability of insulating materials and spacings to withstand specified overvoltages for a specified time without flashover or puncture.

differential protection - A method of apparatus protection in which an internal fault is identified by comparing electrical conditions at all terminals of the apparatus.

differential relay - A relay that by its design or application is intended to respond to the difference between incoming and outgoing electrical quantities associated with the protected apparatus.

digital input - See **binary input**.

directional control (as applied to a protective relay or relay scheme) - A qualifying term that indicates a means of controlling the operating force in a nondirectional relay so that it will not operate until the two or more phasor quantities used to actuate the controlling means (directional relay) are in a predetermined band of phase relations with a reference input.

directional-ground relay - A directional relay used primarily to detect single-phase-to-ground faults, but also sensitive to double-phase-to-ground faults. This type of relay is usually operated from the zero-sequence components of voltage and current, but is sometimes operated from negative-sequence quantities.

directional-overcurrent protection - A method of protection in which an abnormal condition within the protected equipment is detected by the current being in excess of a predetermined amount and in a predetermined band of phase relations with a reference input.

directional-overcurrent relay - A relay consisting of an overcurrent unit and a directional unit combined to operate jointly.

directional-power relay - A relay that operates in conformance with the direction of power.

directional relay - A relay that responds to the relative phase position of a current with respect to another current or voltage reference.

display editor - A software program associated with a microprocessor relay used to edit the graphics and functions of the relay's control display.

Glossary

distance protection - A method of line protection in which an abnormal condition within a predetermined electrical distance of a line terminal on the protected circuit is detected by the measurement of system conditions at that terminal.

distance relay - A generic term covering those forms of protective relays in which the response to the input quantities is primarily a function of the electrical circuit distance between the relay location and the point of fault.

drift - An undesired but relatively slow change in output over a period of time. The change is unrelated to the input, environment, or load.

dropout (of a relay) - A term for contact operation (opening or closing) as a relay just departs from pickup. Dropout also identifies the maximum value of an input quantity that will allow the relay to depart from pickup.

dropout ratio (of a relay) - The ratio of dropout to pickup of an input quantity.

dropout time (of a relay) - The time interval to dropout following a specified change of input conditions.

dual release (trip) - A release that combines the function of a delayed and an instantaneous release.

E

EEPROM - Electrically Erasable Programmable Read-Only Memory.

electrical test - A test to ascertain the performance characteristics while functioning under controlled conditions.

electrically reset relay - A relay that is so constructed that it remains in the picked-up condition even after the input quantity is removed—an independent electrical input is required to reset the relay.

electromagnetic relay - An electromechanical relay that operates principally by action of an electromagnetic element that is energized by the input quantity.

electromechanical relay - A relay that operates by physical movement of parts resulting from electromagnetic, electrostatic, or electrothermic forces created by the input quantities.

EPROM - Erasable Programmable Read-Only Memory.

equipment qualification - The generation and maintenance of evidence to ensure that the equipment will operate upon demand to meet the system performance requirements.

F

failure - The termination of the ability of an item to perform its required function.

failure mechanism - The physical, chemical, or other process that results in failure.

failure mode - The effect in which a failure is observed.

failure rate - The expected number of failures of a given type per item in a given time interval or in a given number of operating cycles.

failure to trip - In the performance of a relay or relay system, the lack of tripping that should have occurred considering the objectives of the relay system design.

false tripping - In the performance of a relay or relay system, the tripping that should not have occurred considering the objectives of the relay system design.

fault bus (fault ground bus) - A bus connected to normally grounded parts of electric equipment, so insulated that all of the ground current passes to ground through fault detecting means.

fault bus protection (relaying) - A method of ground-fault protection that makes use of a fault bus.

fault-detector relay - A monitoring relay whose function is to limit the operation of associated protective relays to specific system conditions.

fault incidence angle - The phase angle as measured between the instant of fault inception and a selected reference such as the zero point on a current or voltage wave.

fault location - An algorithm within a microprocessor relay that calculates impedance to determine distance from the relay location to the fault.

frequency relay - A relay that responds to the frequency of an alternating electrical input quantity.

G

ground overcurrent - The net (phasor sum) current flowing in the phase and neutral conductors or the total current flowing in the normal neutral to ground connection that exceeds a predetermined value.

ground protection - A method of protection in which faults to ground within the protected equipment are detected.

ground relay - A relay that by its design or application is intended to respond primarily to system ground faults.

Glossary

groundable parts - Those parts that may be connected to ground without affecting operation of the device.

grounded parts - The parts that are intentionally connected to ground.

H

hand-reset relay (mechanically reset relay) - A relay that is so constructed that it remains in the picked-up condition even after the input quantity is removed. Specific manual action is required to reset the relay.

harmonic-restraint relay - A restraint relay that is so constructed that its operation is restrained by harmonic components of one or more separate input quantities.

high-speed relay - A relay that operates in less than a specified time. Three cycles on a 60 Hz basis is generally considered high speed.

I

IED - Intelligent Electronic Device. Usually used to designate a microprocessor-based protective relay or any other field device having remote communications capability.

IEEE - Institute of Electrical and Electronics Engineers, Inc.

impedance relay - A distance relay in which the threshold value of operation depends only on the magnitude of the ratio of voltage to current applied to the relay, and is substantially independent of the phase angle of the impedance.

impulse time margin - In the operation of a relay, the difference between characteristic operating times and the critical impulse times.

incorrect relay operation - Any output response or lack of output response by the relay that, for the applied input quantities, is not correct.

incorrect relaying-system performance - Any operation or lack of operation of the relays or associated equipment that, under existing conditions, does not conform to correct relaying-systems performance.

induction cup (of a relay) - A form of relay armature in the shape of a cylinder with a closed end that develops operating torque by its location within the fields of electromagnets that are excited by the input quantities.

induction cylinder (of a relay) - A form of relay armature in the shape of an open-ended cylinder that develops operating torque by its location within the fields of electromagnets that are excited by the input quantities.

induction disk (of a relay) - A form of relay armature in the shape of a disk that usually serves the combined function of providing an operating torque by its location within the fields of an electromagnet excited by the input quantities and a restraining force by motion within the field of a permanent magnet.

induction loop (of a relay) - A form of relay armature consisting of a single turn or loop that develops operating torque by its location within the fields of electromagnets that are excited by the input quantities.

independent power operation - An operation by means of energy other than manual where the completion of the operation is independent of the continuity of the power supply.

initiating relay - A programming relay whose function is to constrain the action of dependent relays until after it has operated.

input (to a relay) - A physical quantity or quantities to which the relay is designed to respond; operating characteristics of a given manufacturer's line of such relays.

inspection - Examination or measurement to verify whether an item or activity conforms to specified requirements.

installed life - The interval from installation to removal during which the equipment or component thereof may be subject to design service conditions and system demands.

instantaneous - A qualifying term indicating that no delay is purposely introduced in the action of the device.

interposing relay (of a supervisory system) - An auxiliary relay at the master or remote station, the contacts of which serve: 1) to energize a circuit (for closing, opening, or other purpose) of an element of remote station equipment when the selection of a desired point has been completed and then suitable operating signals are received through the supervisory equipment from the master station; or 2) to connect in the circuit the telemeter transmitting and receiving equipments, respectively, at the remote and master stations. The interposing relays are considered part of a supervisory system.

inverse-time relay - A relay in which the input quantity and operating time are inversely related throughout at least a substantial portion of the performance range. Types of inverse-time relays are frequently identified by such modifying adjectives as definite minimum time, moderately, very, and extremely to identify relative degree of inverseness of the operating characteristics of a given manufacturer's line of such relays.

L

latching relay - A relay that is so constructed that it maintains a given position by means of a mechanical latch until released mechanically or electrically.

level detector - A device that produces a change in output at a prescribed input level.

Glossary

line terminal - A connection to a line with equipment that can feed energy into a fault on the line in sufficient magnitude to require consideration in the relay pan and that has means for automatic disconnection.

linear-impedance relay - A distance relay for which the operating characteristic on an R-X diagram is a straight line.

linking - The process by which a measured value or other information available within a microprocessor relay is associated with a graphic display to element to provide real-time display of the information on the relay's control display.

load shedding - The process of deliberately removing preselected loads from a power system in response to an abnormal condition in order to maintain the integrity of the system.

local backup - A form of backup protection in which the backup protective relays are at the same station as the primary protective relays.

lockout relay - An electrically reset or hand- reset auxiliary relay whose function is to hold associated devices inoperative until it is reset.

loss-of-excitation relay - A relay that compares the alternating voltages and currents at the terminal of a synchronous machine and, respectively, at the remote and master stations. The interposing relays are considered part of a supervisory system. The lossOf-excitation relay operates to produce an output if the relationship between these quantities indicates that the machine has substantially lost its field excitation.

low-voltage system - An electrical system having a maximum root-mean-square (rms) voltage of less than 1000 V.

M

maintainability - The ease with which equipment can be maintained including the ease with which maintenance can be performed in accordance with prescribed requirements.

maintenance - The combination of all technical and corresponding administrative actions intended to retain an item in, or restore it to, a state in which it can perform its required function.

maintenance interval - The period, defined in terms of real time, operating time, number of operating cycles, or a combination of these, during which satisfactory performance is required without maintenance or adjustments.

mandatory maintenance - Periodic maintenance required by insurance, operating license, vendor warranty, government regulations, or other safety regulations.

maximum design voltage - The highest root mean square or direct voltage at which a relay is designed to be continuously energized.

mean - The average value of a random sample or population.

mean time between failures - A measure of reliability giving the time before first failure or, for repairable equipment, the average time between repairs.

medium voltage system - An electrical system having a maximum rms AC voltage of 1000 V to 13.8 KV.

mho relay - A distance relay for which the inherent operating characteristic on an R-X diagram is a circle that passes through the origin.

mild environment - An environment that would at no time be significantly more severe than the environment that would occur during normal plant operations, including anticipated operational occurrences.

modified impedance relay - An impedance form of distance relay for which the operating characteristic of the distance unit on an R-X diagram is a circle having its center displaced from the origin.

monitoring relay - A relay that has as its function to verify that system or control-circuit conditions conform to prescribed limits.

multirestraint relay - A restraint relay that is so constructed that its operation may be restrained by more than one input quantity.

N

negative-phase-sequence relay - A relay that responds to the negative-phase-sequence component of a polyphase input quantity.

NEMA - National Electrical Manufacturer's Association.

neutral relay - A relay that responds to quantities in the neutral of a power circuit.

NFPA - National Fire Protection Association.

nominal system voltage - A nominal value assigned to designate a system of a given voltage class.

normal-frequency recovery voltage - The normal-frequency rms voltage that occurs across the terminals of an AC circuit-interrupting device after the interruption of the current and after the high-frequency transients have subsisted.

normality test - A statistical test to determine if a sample is normally distributed.

NRC - U.S. Nuclear Regulatory Commission.

*Glossary***O**

offset (impedance relay) - The distance from the origin of the R - X axis to the closest point on the circumference of the characteristic circle.

open-phase protection - A form of protection that operates to disconnect the protected equipment on the loss of current in one phase conductor of a polyphase circuit, or to prevent the application of power to the protected equipment on the absence of one or more phase voltages of a polyphase system.

open-phase relay - A polyphase relay designed to operate when one or more input phases of a polyphase circuit are open.

operable - For a given point in time, a device or equipment that has been demonstrated by testing at that time to have met a set of functional performance requirements under specified test conditions.

operating characteristic - The response of the relay to the input quantities that result in relay operation.

operating time (relay) - The time interval from occurrence of a specified input condition to a specified operation.

operating voltage - The voltage of the system on which a device is operated.

outlier - A data point significantly different in value from the rest of the sample.

overcurrent protection - A form of protection that operates when current exceeds a predetermined value.

overcurrent relay - A relay that operates when its input current exceeds a predetermined value.

overcurrent release (trip) - A release that operates when the current in the main circuit is equal to or exceeds the release setting.

overreach - The extension of the zone of protection beyond that indicated by the relay setting.

overreaching protection - A form of protection in which the relays at one terminal operate for faults beyond the next terminal. They may be constrained from tripping until an incoming signal from a remote terminal has indicated whether the fault is beyond the protected line section.

overspeed protection - A form of protection that operates when the speed of rotation exceeds a predetermined value.

overtravel - The amount of continued movement of the responsive element after the input is changed to a value below pickup.

overvoltage relay - A relay that operates when its input voltage exceeds a predetermined value.

overvoltage release (trip) - A release that operates when the voltage of the main circuit is equal to or exceeds the release setting.

P

percentage differential relay - A differential relay in which the designed response to the phasor difference between incoming and outgoing electrical quantities is modified by a restraining action of one or more of the input quantities.

periodic test - A test performed at scheduled intervals to detect failures and verify operability.

permissive - A general term indicating that functional cooperation of two or more relays is required before control action can become effective.

phase-balance relay - A relay that responds to differences between quantities of the same nature associated with different phases of a normally balanced polyphase circuit.

phase-comparison protection - A form of pilot protection that compares the relative phase-angle position of specified currents at the terminals of a circuit.

phase relay - A relay that by its design or application is intended to respond primarily to phase conditions of the power system.

phase-sequence relay - A relay that responds to the order in which the phase voltages or currents successively reach their maximum positive values.

phase-sequence reversal protection - A form of protection that prevents energization of the protected equipment on the reversal of the phase sequence in a polyphase circuit.

phase-undervoltage protection - A form of protection that disconnects or inhibits connection of the protected equipment on deficient voltage in one or more phases of a polyphase circuit.

phase-undervoltage relay - A relay that operates when one or more phase voltages in a normally balanced circuit are less than a predetermined value.

pickup - The action of a relay as it makes a designated response to progressive increase of input. As a qualifying term, pickup refers to the state of a relay when all response to progressive increase of input has been completed. Also, pickup is used to identify the minimum value of an input quantity reached by progressive increases that will cause the relay to reach the pickup state from reset.

pilot protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Glossary

pilot wire protection - Pilot protection in which a metallic circuit is used for the communicating means between relays at the circuit terminals.

PM - Periodic maintenance.

polarization - A term identifying the input that provides a reference for establishing the direction of system phenomena such as direction of power or reactive flow, or direction to a fault or other disturbance on a power system.

polyphase relay - A descriptive term indicating that the relay is responsive to polyphase alternating electrical input quantities.

positive-phase-sequence relay - A relay that responds to the positive-phase-sequence component of a polyphase input quantity.

potential transformer - see **Voltage transformer**.

power relay - A relay that responds to a suitable product of voltage and current in an electric circuit.

preventive maintenance - Regularly scheduled inspections, tests, servicing, repairs, and replacements intended to reduce the frequency and impact of equipment failures.

primary protection - First-choice relay protection in contrast with backup relay protection.

product relay - A relay that operates in response to a suitable product of two alternating electrical input quantities.

protective relay - A relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action.

Q

qualified life - The period of time for which satisfactory performance can be demonstrated for a specific set of service conditions.

R

radial system - A system in which independent feeders branch out radially from a common source of supply.

random - Describing a variable whose value at a particular future instant cannot be predicted exactly, but can be estimated only by a probability distribution function.

rate-of-change protection - A form of protection in which an abnormal condition causes disconnection or inhibits connection of the protected equipment in accordance with the rate of change of current, voltage, power, frequency, or pressure.

rate-of-change relay - A relay that responds to the rate of change of current, voltage, power, frequency, or pressure.

rated - A qualifying term that, when applied to an operating characteristic, indicates the designated limit or limits of the characteristic for application under specified conditions.

raw data - As-found minus as-left test data used to characterize the performance of a device or functionally equivalent group of devices.

reactance relay - A linear-impedance form of distance relay for which the operating characteristic of the distance unit on an R-X diagram is a straight line of constant reactance.

reach - The extent of the protection afforded by a relay in terms of the impedance or circuit length as measured from the relay location.

reactive power relay - A power relay that responds to reactive power.

reclosing relay - A programming relay whose function is to initiate the automatic reclosing of a circuit breaker.

regulating relay - A relay whose function is to detect a departure from specified system operating conditions and to restore normal conditions by acting through supplementary equipment.

relay - An electrical device designed to respond to input conditions in a prescribed manner after specified conditions are met to cause contact operation or similar abrupt change in associated electrical control circuits.

relay backup - That part of the backup protection that operates in the event of failure of the primary relays.

release-delay (grip-delay) setting - A calibrated setting of the time interval between the time when the actuating value reaches the release setting and the time when the release operates.

release (trip) setting - A calibrated point at which the release is set to operate.

reliability - A measure of the degree of certainty that the relay, or relay system, will perform correctly.

remote backup - A form of backup protection in which the protection is at a station or stations other than that with the primary protection.

Glossary

reset - The action of a relay as it makes designated response to decreases in input. Reset as a qualifying term denotes the state of the relay when all response to decrease of input has been completed. Reset is also used to identify the maximum value of an input quantity reached by progressive decreases that will permit the relay to reach the state of complete reset from pickup.

reset time - The time interval from occurrence of specified conditions to reset.

residual relay - A relay that is so applied that its input, derived from external connections of instrument transformers, is proportional to the zero-phase-sequence component of a polyphase quantity.

resistance relay - A linear-impedance form of distance relay for which the operating characteristic on an R-X diagram is a straight line of constant resistance below the release setting for a specified time.

restraint relay - A relay so constructed that its operation in response to one input is restrained or controlled by a second input.

reverse-current relay - A relay that operates on a current flow in a direct-current circuit in a direction opposite to a predetermined reference direction.

reverse-current release - A release that operates upon reversal of the direct current in the main circuit from a predetermined direction.

R-X diagram - A graphic presentation of the characteristics of a relay unit in terms of the ratio of voltage to current and the phase angle between them.

S

saturation - A high flux density in the current transformer iron core created by abnormally high primary currents, high secondary burden, or a combination of these factors.

seal-in relay - An auxiliary relay that remains picked up through one of its own contacts that bypass the initiating circuit until deenergized by some other device.

security - That facet of reliability that relates to the degree of certainty that a relay or relay system will not operate incorrectly.

selective opening (tripping) - The application of switching devices in series such that, of the devices carrying fault current, only the device nearest the fault will open and the devices closer to the source will remain closed and carry the remaining load.

selective release (trip) - A delayed release with selective settings that will automatically reset if the actuating quantity falls and remains below the release setting for a specified time.

selectivity - A general term describing the interrelated performance of relays and breakers, and other protective devices. Complete selectivity is obtained when a minimum amount of equipment is removed from service for the isolation of a fault or other abnormality.

self-test relay (automatically reset relay) - A relay that is so constructed that it returns to its reset position following an operation after the input quantity is removed.

service conditions - The conditions under which the equipment is to be applied.

sequence network - An electrical circuit that produces an output proportional to one or more of the sequence components of a polyphase system of voltages or currents (for example, positive-sequence network, negative-sequence network, or zero-sequence network).

setting - The desired characteristic obtained as a result of having set a device (stated in terms of calibration markings or of actual performance bench marks such as pickup current and operating time at a given value of input).

setting error - The departure of the actual performance from the desired performance resulting from errors in adjustment or from limitations in testing or measuring techniques.

setting limitation - The departure of the actual performance from the desired performance resulting from limitations of adjusting devices.

short circuit - An abnormal condition (including an arc) of relatively low impedance, made accidentally or intentionally, between two points of different potential.

short-time current - The current carried by a device, an assembly, or a bus for a specified short time interval.

short-time-delay phase or ground trip element - A direct-acting trip device element that functions with a purposely delayed action (milliseconds).

short-time rating - The highest value of current or voltage or their products that the relay can stand without injury for specified short-time intervals. (For alternating-current circuits, root-mean-square total value including the direct-current component is used.) The rating recognizes the limitations imposed by both the thermal and electromagnetic effects.

shunt release - A release energized by a source of voltage. mechanically or electrically, to indicate visibly that the relay has operated or completed its function.

solid-state relay - A static relay constructed exclusively of solid-state components.

split-winding protection - A form of differential protection in which the current in all or part of the winding is compared to the normally proportional current in another part of the winding.

Glossary

startup - The action of a relay as it just departs from complete reset. Startup is also used as a qualifying term to identify the minimum value of the input quantity that will permit this condition.

static relay - A relay in which the designed response is developed by electronic, solid-state, magnetic, or other components without mechanical motion.

sudden-pressure relay - A relay that operates by the rate of rise in pressure of a liquid or gas.

susceptance relay - An mho-type distance relay for which the center of the operating characteristic on the R-X diagram is on the X axis.

symmetrical component - That portion of the total current that constitutes the symmetry.

synchronism-check relay - A verification relay whose function is to operate when two input voltage phasors are within predetermined limits.

synchronizing relay - A programming relay whose function is to initiate the closing of a circuit breaker between two ac sources when the voltages of these two sources have a predetermined relationship of magnitude, phase angle, and frequency.

T

temperature relay - A relay whose operation is caused by specified external temperature.

time-dependent drift - The tendency for the magnitude of drift to vary with time.

time dial - An adjustable graduated element of a relay by which the prescribed relay operating time can be varied under fixed input conditions.

time-independent drift - The tendency for the magnitude of drift to show no specific trend with time.

time-overcurrent relay - An overcurrent relay in which the input current and operating time are inversely related throughout a substantial portion of the performance range.

time-undervoltage protection - A form of undervoltage protection that disconnects the protected equipment upon a deficiency of voltage after a predetermined time interval.

timing relay - An auxiliary relay whose function is to introduce one or more time delays in the completion of an associated function.

tolerance - The allowable variation from a specified or true value.

tolerance interval - An interval that contains a defined proportion of the population to a given probability.

torque control - A method of constraining the pickup of a relay by preventing the torque-producing element from developing operating torque until after another associated relay unit operates.

transfer trip - A form of remote trip in which a communication channel is used to transmit a trip signal from the relay location to a remote location.

transient response - The manner in which a relay or relay system responds to a sudden change in the input.

travel - The amount of movement in either direction (towards pickup or reset) of a responsive element.

trip (or tripping) - Pertaining to a release that initiates an opening or a closing operation or other specified action.

trip-free relay - An auxiliary relay whose function is to open the closing circuit of an electrically operated switching device so that the opening operation can prevail over the closing operation.

U

undercurrent relay - A relay that operates when the current is less than a predetermined value.

underreaching protection - A form of protection in which the relays at a given terminal do not operate for faults at remote locations on the protected equipment, the given terminal being cleared by other relays with different performance characteristics or by a transferred trip signal from a remote terminal similarly equipped with underreaching.

undervoltage protection - A form of protection that operates when voltage is less than a predetermined value.

undervoltage relays - A relay that operates when its voltage is less than a predetermined value.

undervoltage release trip - A release that operates when the voltage of the main circuit is equal to or less than the release setting.

V

voltage balance relay - A balance relay that operates by comparing the magnitudes of two voltage inputs.

voltage transformer - An instrument transformer intended to have its primary winding connected in shunt with a power supply circuit, the voltage of which is to be measured or controlled.

Glossary

voltage rating - The voltage at a specified frequency that may be sustained by the relay for an unlimited period without causing any of the prescribed limitations to be exceeded.

voltage relay - A relay that responds to voltage.

voltage restraint - A method of restraining the operation of a relay by means of a voltage input that opposes the typical response of the relay to other inputs.

voltage-phase-balance protection - A form of protection that disconnects or prevents the connection of the protected equipment when the voltage unbalance of the phases of a normally balanced polyphase system exceeds a predetermined amount.

volts per hertz relay - A relay whose pickup is a function of the ratio of voltage to frequency.

W

watchdog timer - A routine within the self-diagnostics algorithm of microprocessor relays. If the microprocessor fails to complete its processing routine within a given time limit, an alarm output is given.

withstand voltage - The voltage that electrical equipment is capable of withstanding without failure or disruptive discharge when tested under specified conditions.

Z

zero-phase-sequence relay - A relay that responds to the zero-phase-sequence component of a polyphase input quantity.

zone of protection - That segment of the power system in which the occurrence of assigned abnormal conditions should cause the protective relay system to operate.

C

OVERVIEW OF INDUSTRY STANDARDS

Industry standards are used to define accepted practices for system or product design, application, installation, service, operation, or maintenance. The following sections discuss some of these standards and their applicability to protective relay design, application, and maintenance.

C.1 Institute of Electrical and Electronics Engineers (IEEE)

1. ANSI/IEEE 242-1986, *IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems*

This standard discusses electrical protection for industrial and commercial facilities. Chapter 4 of the standard provides good general information relating to the selection and application of protective relays. Protection of motors, generators, busses, and transformers is also covered. Chapter 15 addresses maintenance, testing, and calibration of electrical protection equipment, including protective relays.

2. ANSI/IEEE 741-1990, *IEEE Standard Criteria for the Protection of Class IE Power Systems and Equipment in Nuclear Power Generating Stations*

This standard prescribes criteria for the protection of Class IE electrical equipment and systems at nuclear power plants. The standard addresses general and specific design requirements, documentation and records, testing, and surveillances.

3. ANSI/IEEE C37.2-1991, *IEEE Standard Electrical Power System Device Function Numbers*

This standard establishes unique numbers to identify the function of electrical devices commonly used in electrical power systems. Device function numbers for all protective relays are defined. The numbers established by this standard are used extensively in electrical drawings, specifications, reports, and other related engineering documents.

4. ANSI/IEEE C37.90-1989, *IEEE Standard Relays and Relay Systems Associated with Electric Power Apparatus*

This standard is a primary reference for protective relays. It standardizes service conditions, ratings, performance requirements, and testing requirements for power system relays. Relay classifications and terminology are also addressed. The standard is a good reference for fundamental design and test requirements used by manufacturers to design and build protective relays.

*Overview of Industry Standards**5. ANSI/IEEE C37.90.1-1989, IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems*

This standard establishes standardized surge withstand capability (SWC) tests for protective relays. The tests are primarily used by manufacturers to verify design adequacy of their products and are not generally performed by users.

6. ANSI/IEEE C37.90.2-1989, IEEE Trial-Use Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

This standard establishes a test method for evaluating the susceptibility of solid-state protective and control relays to electromagnetic interference. Similar to SWC tests, the test specified in this standard is primarily used by manufacturers to verify design adequacy of their products and is not generally performed by users.

7. ANSI/IEEE C37.91-1985, IEEE Guide for Protective Relay Applications to Power Transformers

This standard addresses protection of power transformers. Protection philosophy, practical considerations, and economic factors are covered in the standard. The application of various types of protective relays is covered in considerable depth.

8. ANSI/IEEE C37.95-1989, IEEE Guide for Protective Relaying of Utility-Consumer Interconnections

This standard contains information on protective relay practices applicable to utility-consumer interconnections.

9. ANSI/IEEE C37.96-1988, IEEE Guide for AC Motor Protection

This standard addresses protection of ac motors. Generally accepted practices for motor protection are reviewed. Protection philosophy, protective relay applications, and relaying schemes are covered in depth.

10. ANSI/IEEE C37.97-1979, IEEE Guide for Protective Relay Applications to Power System Buses

This standard addresses protection of power system buses. Various protection methods for typical substation and switchyard bus arrangements are covered. The standard is not directly applicable to the protection of in-plant distribution switchgear.

11. ANSI/IEEE C37.98-1987, IEEE Standard Seismic Testing of Relays

This standard specifies procedures for seismic testing of relays used in power systems. The standard is primarily used to evaluate the seismic performance of protective and auxiliary relays that are intended for use in Class IE electrical systems at nuclear power plants. This standard

supports IEEE C37.105-1987, *IEEE Standard for Qualifying Class IE Protective Relays and Auxiliaries for Nuclear Power Generating Stations*.

12. ANSI/IEEE C37.99-1990, *IEEE Guide for the Protection of Shunt Capacitor Banks*

This standard discusses the application of protective relays to shunt capacitors used in substations.

13. ANSI/IEEE C37.100-1981, *Definitions for Power Switchgear*

This standard is the primary reference source for terms and definitions applicable to power switchgear, including protective relays. The standard is a good reference document for unfamiliar terms.

14. ANSI/IEEE C37.101-1985, *IEEE Guide for Generator Ground Protection*

This standard provides guidance for the protection of synchronous generators against ground faults. Protective relay applications and relaying schemes are covered in depth.

15. ANSI/IEEE C37.102-1987, *IEEE Guide for AC Generator Protection*

This standard provides guidance for the protection of ac synchronous generators. Generally accepted protection practices are reviewed and the application of protective relays is summarized. Abnormal conditions and faults requiring protective action are discussed at length.

16. ANSI/IEEE C37.103-1990, *IEEE Guide for Differential and Polarizing Relay Circuit Testing*

This standard provides recommended tests to ensure that ground relay polarizing and differential relays are connected properly. The standard is limited to ensuring proper circuit connections and does not address routine testing or calibration. These tests are applicable to system startup.

17. ANSI/IEEE C37.105-1987, *IEEE Standard for Qualifying Class IE Protective Relays and Auxiliaries for Nuclear Power Generating Stations*

This standard describes the requirements and methods to be used for qualification of Class IE protective relays. The standard is intended to demonstrate the design adequacy of protective relays under normal and abnormal conditions, during design basis events, and after a design basis event.

18. ANSI/IEEE C37.106-1987, *IEEE Guide for Abnormal Frequency Protection for Power Generating Plants*

This standard provides guidance for the application of protective relays to power plant equipment to guard against damage from abnormal frequencies.

C.2 National Fire Protection Association (NFPA)

1. ANSI/NFPA 70-1993, *National Electrical Code*

This code is a nationally accepted guide for the safe design and installation of electrical conductors, equipment, and systems. The code contains provisions considered necessary to ensure the practical safeguarding of people and property from the hazards associated with electricity. The code serves as a primary reference source for electrical installations in the United States.

2. ANSI/NFPA 70B-1990, *Recommended Practice for Electrical Equipment Maintenance*

The purpose of this code is to reduce the hazards to life and property that can result from failure or malfunction of industrial electrical systems and equipment. The code provides good general guidance for preventive maintenance programs associated with industrial electrical equipment. General maintenance recommendations for protective relays are included in Appendix I of the code.

3. ANSI/NFPA 70E-1988, *Standard for Electrical Safety Requirements for Employee Workplaces*

This standard addresses electrical safety requirements that are necessary for the practical safeguarding of employees in the work place.

C.3 National Electrical Testing Association (NETA)

1. NETA ATS-1991, *Acceptance Testing Specifications for Electrical Power Distribution Equipment and Systems*

This document provides recommendations for acceptance testing of electrical power systems and equipment. It provides practical recommendations intended to identify shipping damage, wiring errors, manufacturing defects, and other similar problems that can occur during startup of new equipment or systems. Some brief guidance is provided for protective relays.

2. NETA MTS-1989, *Maintenance Testing Specifications for Electrical Power Distribution Equipment and Systems*

This document is intended to list the majority of field tests available for assessing the condition of electrical distribution equipment. Suitability of continued service and expected reliability are emphasized. Maintenance recommendations for protective relays are provided.

D

ELECTRICAL POWER SYSTEM DEVICE FUNCTION NUMBERS

1—Master Element

A device such as a control switch that serves, directly or through such permissive devices as protective and time-delay relays, to place equipment in or out of operation.

2—Time-Delay Starting or Closing Relay

A device that functions to give a desired amount of time delay before or after any point of operation in a switching sequence or protective relay system, except as specifically provided by device functions 48, 62, 79, and 82.

3—Checking or Interlocking Relay

A device that operates in response to the position of one or more other devices or predetermined conditions in a piece of equipment or circuit, to allow an operating sequence to proceed, or to stop, or to provide a check of the position of these devices or conditions for any purpose.

4—Master Contactor

A device, generally controlled by device function 1 or the equivalent and the required permissive and protective devices, that serves to make and break the necessary control circuits to place equipment into operation under the desired conditions and to take it out of operation under abnormal conditions.

5—Stopping Device

A control device used primarily to shut down equipment and hold it out of operation. A stopping device may be manually or electrically actuated, but it excludes the function of electrical lockout (see device function 86) on abnormal conditions.

6—Starting Circuit Breaker

A device whose principal function is to connect a machine to its source of starting voltage.

7—Rate-of-Change Relay

A device that operates when the rate-of-change of the measured quantity exceeds a threshold value, except as defined by device 63.

8—Control Power Disconnecting Device

A device such as a knife switch, circuit breaker, or pull-out fuse block used for the purpose of connecting and disconnecting the source of control power to and from the control bus or equipment.

9—Reversing Device

A device that is used for the purpose of reversing a machine field or for performing any other reversing function.

10—Unit Sequence Switch

A device that is used to change the sequence in which units may be placed in and out of service in multiple-unit equipment.

11—Multifunctional Device

A device that performs three or more comparatively important functions that can be designated only by combining several device function numbers. All of the functions performed by device 11 shall be defined in the drawing legend, device function definition list or relay setting record.

12—Overspeed Device

A device, usually direct connected, that operates on machine overspeed.

13—Synchronous-Speed Device

A device such as a centrifugal-speed switch, a slip-frequency relay, a voltage relay, an undercurrent relay, or any other type of device that operates at approximately the synchronous speed of a machine.

14—Underspeed Device

A device that functions when the speed of a machine falls below a predetermined value.

15—Speed or Frequency Matching Device

A device that functions to match and hold the speed or frequency of a machine or a system equal to, or approximately equal to, that of another machine, source, or system.

16—Not Used

Reserved for future application.

17—Shunting or Discharge Switch

A device that serves to open or close a shunting circuit around any piece of apparatus (except a resistor) such as a machine field, a machine armature, a capacitor, or a reactor.

NOTE — This excludes devices that perform such shunting operations as may be necessary in the process of starting a machine by devices 6 or 42 (or their equivalent) and also excludes device function 73 that serves for the switching of resistors.

18—Accelerating or Decelerating Device

A device that is used to close or cause the closing of circuits that are used to increase or decrease the speed of a machine.

19—Starting-to-Running Transition Contactor

A device that operates to initiate or cause the automatic transfer of a machine from the starting to the running power connection.

20—Electrically Operated Valve

An electrically operated, controlled, or monitored device used in a fluid, air, gas, or vacuum line.

21—Distance Relay

A device that functions when the circuit admittance, impedance, or reactance increases or decreases beyond a predetermined value.

22—Equalizer Circuit Breaker

A device that serves to control or make and break the equalizer or the current-balancing connections for a machine field, or for regulating equipment, in a multiple-unit installation.

23—Temperature Control Device

A device that functions to control the temperature of a machine or other apparatus, or of any medium, when its temperature falls below or rises above a predetermined value.

24—Volts per Hertz Relay

A device that operates when the ratio of voltage to frequency is above a preset value or is below a different preset value. The relay may have any combination of instantaneous or time-delayed characteristics.

25—Synchronizing or Synchronism-Check Relay

A synchronizing device produces an output that causes closure at zero-phase angle difference between two circuits. It may or may not include voltage and speed control. A synchronism-check relay permits the paralleling of two circuits that are within the prescribed limits of voltage magnitude, phase angle, and frequency.

26—Apparatus Thermal Device

A device that functions when the temperature of the protected apparatus (other than the load-carrying windings of machines and transformers as covered by device function number 49) or of a liquid or other medium exceeds a predetermined value; or when the temperature of the protected apparatus or of any medium decreases below a predetermined value.

27—Undervoltage Relay

A device that operates when its input voltage is less than a predetermined value.

28—Flame Detector

A device that monitors the presence of the pilot or main flame in such apparatus as a gas turbine or a steam boiler.

29—Isolating Contactor or Switch

A device that is used expressly for disconnecting one circuit from another for the purposes of emergency operation, maintenance, or test.

30—Annunciator Relay

A non-automatically reset device that gives a number of separate visual indications upon the functioning of protective devices and that may also be arranged to perform a lockout function.

31—Separate Excitation Device

A device that connects a circuit (such as the shunt field of a synchronous converter) to a source of separate excitation during the starting sequence.

32—Directional Power Relay

A device that operates on a predetermined value of power flow in a given direction such as reverse power flow resulting from the motoring of a generator upon loss of its prime mover.

33—Position Switch

A device that makes or breaks contact when the main device or piece of apparatus that has no device function number reaches a given position.

34—Master Sequence Device

A device such as a motor-operated multicontact switch, or the equivalent, or a programmable device, that establishes or determines the operating sequence of the major devices in equipment during starting and stopping or during sequential switching operations.

35—Brush-Operating or Slip-Ring Short-Circuiting Device

A device for raising, lowering, or shifting the brushes of a machine; short-circuiting its slip rings; or engaging or disengaging the contacts of a mechanical rectifier.

36—Polarity or Polarizing Voltage Device

A device that operates, or permits the operation of, another device on a predetermined polarity only or that verifies the presence of a polarizing voltage in equipment.

37—Undercurrent or Underpower Relay

A device that functions when the current or power flow decreases below a predetermined value.

38—Bearing Protective Device

A device that functions on excessive bearing temperature or on other abnormal mechanical conditions associated with the bearing (such as undue wear), which may eventually result in excessive bearing temperature or failure.

39—Mechanical Condition Monitor

A device that functions upon the occurrence of an abnormal mechanical condition (except that associated with bearings as covered under device function 38) such as excessive vibration, eccentricity, expansion, shock, tilting, or seal failure.

40—Field Relay

A device that functions on a given or abnormally high or low value or failure of machine field current, or on an excessive value of the reactive component of armature current in an ac machine indicating abnormally high or low field excitation.

41—Field Circuit Breaker

A device that functions to apply or remove the field excitation of a machine.

42—Running Circuit Breaker

A device whose function is to connect a machine to its source of running or operating voltage. This function may also be used for a device such as a contactor, which is used in series with a circuit breaker or other fault-protecting means, primarily for frequent opening and closing of the circuit.

43—Manual Transfer or Selector Device

A manually operated device that transfers control or potential circuits in order to modify the plan of operation of the associated equipment or of some of the associated devices.

44—Unit Sequence Starting Relay

A device that functions to start the next available unit in multiple-unit equipment upon the failure or non-availability of the normally preceding unit.

45—Atmospheric Condition Monitor

A device that functions upon the occurrence of abnormal atmospheric conditions such as damaging fumes, explosive mixtures, smoke, or fire.

46—Reverse-Phase or Phase-Balance Current Relay

A device in a polyphase circuit that operates when the polyphase currents are of reverse-phase sequence or when the polyphase currents are unbalanced or when the negative phase-sequence current exceeds a preset value.

47—Phase-Sequence or Phase-Balance Voltage Relay

A device in a polyphase circuit that functions upon a predetermined value of polyphase voltage in the desired phase sequence, when the polyphase voltages are unbalanced, or when the negative phase-sequence voltage exceeds a preset value.

48—Incomplete Sequence Relay

A device that generally returns the equipment to the normal or off position and locks it out if the normal starting, operating, or stopping sequence is not properly completed within a predetermined time.

49—Machine or Transformer Thermal Relay

A device that functions when the temperature of a machine armature winding or other load-carrying winding or element of a machine or power transformer exceeds a predetermined value.

50—Instantaneous Overcurrent Relay

A device that operates with no intentional time delay when the current exceeds a preset value.

51—AC Time Overcurrent Relay

A device that functions when the ac input current exceeds a predetermined value, and in which the input current and operating time are inversely related through a substantial portion of the performance range.

52—AC Circuit Breaker

A device that is used to close and interrupt an ac power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

53—Exciter or DC Generator Relay

A device that forces the dc machine field excitation to build up during starting or that functions when the machine voltage has built up to a given value.

54—Turning Gear Engaging Device

A device that is electrically operated, controlled, or monitored and that functions to cause the turning gear to engage (or disengage) the machine shaft.

55—Power Factor Relay

A device that operates when the power factor in an ac circuit rises above or falls below a predetermined value.

56—Field Application Relay

A device that automatically controls the application of the field excitation to an ac motor at some predetermined point in the slip cycle.

57—Short-Circuiting or Grounding Device

A device that functions to short-circuit or ground a circuit in response to automatic or manual means.

58—Rectification Failure Relay

A device that functions if a power rectifier fails to conduct or block properly.

59—Overvoltage Relay

A device that operates when its input voltage exceeds a predetermined value.

60—Voltage or Current Balance Relay

A device that operates on a given difference in voltage, or current input or output, of two circuits.

61—Density Switch or Sensor

A device that operates at a given density value or at a given rate of change of density.

62—Time-Delay Stopping or Opening Relay

A device that imposes a time delay in conjunction with the device that initiates the shutdown, stopping, or opening operation in an automatic sequence or protective relay system.

63—Pressure Switch

A device that operates at a given pressure value or at a given rate of change of pressure.

64—Ground Detector Relay

A device that operates upon failure of machine or other apparatus insulation to ground.

NOTE — This function is not applied to a device connected in the secondary circuit of current transformers in a normally grounded power system where other overcurrent device numbers with the suffix G or N should be used; for example, 51N for an ac time overcurrent relay connected in the secondary neutral of the current transformers.

65—Governor

A device consisting of an assembly of fluid, electrical, or mechanical control equipment used for regulating the flow of water, steam, or other media to the prime mover for such purposes as starting, holding speed or lead, or stopping.

66—Notching or Jogging Device

A device that functions to allow only a specified number of operations of a given device or piece of equipment, or a specified number of successive operations within a given time of each other. It is also a device that functions to energize a circuit periodically or for fractions of specified time intervals, or that is used to permit intermittent acceleration or jogging of a machine at low speeds for mechanical positioning.

67—AC Directional Overcurrent Relay

A device that functions at a desired value of ac overcurrent flowing in a predetermined direction.

68—Blocking or Out-of-Step Relay

A device that initiates a pilot signal for blocking of tripping on external faults in a transmission line or in other apparatus under predetermined conditions, or cooperates with other devices to block tripping or reclosing on an out-of-step condition or on power swings.

69—Permissive Control Device

A device with two-positions that in one position permits the closing of a circuit breaker, or the placing of a piece of equipment into operation, and in the other position, prevents the circuit breaker or the equipment from being operated.

70—Rheostat

A device used to vary the resistance in an electric circuit when the device is electrically operated or has other electrical accessories (such as auxiliary, position, or limit switches).

71—Level Switch

A device that operates at a given level value, or on a given rate of change of level.

72—DC Circuit Breaker

A device that is used to close and interrupt a dc power circuit under normal conditions or to interrupt this circuit under fault or emergency conditions.

73—Load-Resistor Contactor

A device that is used to shunt or insert a step of load limiting, shifting, or indicating resistance in a power circuit; to switch a space heater in circuit; or to switch a light or regenerative load resistor of a power rectifier or other machine in and out of circuit.

74—Alarm Relay

A device other than an annunciator (as covered under device function 30) that is used to operate, or that operates in connection with, a visual or audible alarm.

75—Position Changing Mechanism

A device that is used for moving a main device from one position to another in equipment; for example, shifting a removable circuit breaker unit to and from the connected, disconnected, and test positions.

76—DC Overcurrent Relay

A device that functions when the current in a dc circuit exceeds a given value.

77—Telemetry Device

A transmitting device used to generate and transmit to a remote location an electrical signal representing a measured quantity; or a receiver used to receive the electrical signal from a remote transmitter and convert the signal to represent the original measured quantity.

78—Phase-Angle Measuring Relay

A device that functions at a predetermined phase angle between two voltages, between two currents, or between voltage and current.

79—Reclosing Relay

A device that controls the automatic reclosing and locking out of an ac circuit interrupter.

80—Flow Switch

A device that operates at a given flow value, or at a given rate of change of flow.

81—Frequency Relay

A device that responds to the frequency of an electrical quantity, operating when the frequency or rate of change of frequency exceeds or is less than a predetermined value.

82—DC Load-Measuring Reclosing Relay

A device that controls the automatic closing and reclosing of a dc circuit interrupter, generally in response to load circuit conditions.

83—Automatic Selective Control or Transfer Relay

A device that operates to select automatically between certain sources or conditions in equipment or that performs a transfer operation automatically.

84—Operating Mechanism

A device consisting of the complete electrical mechanism or servomechanism including the operating motor, solenoids, or position switches for a tap changer, induction regulator, or any similar piece of apparatus that otherwise has no device function number.

85—Carrier or Pilot-Wire Relay

A device that is operated or restrained by a signal transmitted or received via any communications media used for relaying.

86—Lockout Relay

A device that trips and maintains the associated equipment or devices inoperative until an operator resets it, either locally or remotely.

87—Differential Protective Relay

A device that operates on a percentage, phase angle, or other quantitative difference of two or more currents or other electrical quantities.

88—Auxiliary Motor or Motor Generator

A device used for operating auxiliary equipment such as pumps, blowers, exciters, or rotating magnetic amplifiers.

89—Line Switch

A device used as a disconnecting, load-interrupter, or isolating switch in an ac or dc power circuit. (This device function number is normally not necessary unless the switch is electrically operated or has electrical accessories such as an auxiliary switch or a magnetic lock.)

90—Regulating Device

A device that functions to regulate a quantity or quantities (such as voltage, current, power, speed, frequency, temperature, and load) at a certain value or between certain (generally close) limits for machines, tie lines, or other apparatus.

91—Voltage Directional Relay

A device that operates when the voltage across an open circuit breaker or contactor exceeds a given value in a given direction.

92—Voltage and Power Directional Relay

A device that permits or causes the connection of two circuits when the voltage difference between them exceeds a given value in a predetermined direction and causes these two circuits to be disconnected from each other when the power flowing between them exceeds a given value in the opposite direction.

93—Field-Changing Contactor

A device that functions to increase or decrease, in one step, the value of field excitation on a machine.

94—Tripping or Trip-Free Relay

A device that functions to trip a circuit breaker, contactor, or equipment; to permit immediate tripping by other devices; or to prevent immediate reclosing of a circuit interrupter if it should open automatically, even though its closing circuit is maintained closed.

95-99—Used Only for Specific Applications

These device numbers are used in individual specific installations if none of the functions assigned to the numbers from 1 through 94 are suitable.

E

LISTING OF KEY INFORMATION

The following list provides the location of “Key Point” information in this report.



Key O&M Cost Point

Emphasizes information that will reduce purchase, operating, or maintenance costs.

Referenced Section	Page Number	Key Point
1.0	1-1	Numerical relays have eliminated the degradation that can be expected from the mechanical components of electromechanical relays.
2.1.1	2.1	Because modern multifunctional digital relays allow the relay engineer to have multiple protection elements in one device, the number of relays in a protection scheme has been reduced.
2.1.1	2.2	Digital relays can be installed at a much lower cost and, therefore, the use of digital relays can result in a significant economic savings.
2.2.1.1	2-4	Some relays offer universal power supplies that are capable of handling a large range of both AC and DC voltages. This reduces the potential for catastrophic failure due to human error and helps to reduce the necessary inventory of spare relays.
2.2.1.8	2-6	As the programmable logic capabilities of numeric relays advance (in some cases rivaling or surpassing the capability of stand-alone PLCs), more control devices are being eliminated.
2.3	2-13	The need for preliminary classification was eliminated by the modern multifunctional numeric microprocessor relay. An excellent example is a typical multifunctional generator/motor protection relay that has all of the functionality required to provide complete generator protection in a single box.
2.3	2-15	With the high-powered programmable logic capability of numeric relays, multifunctional relays can replace many types of relays including monitoring, reclosing, and auto-synchronizing relays.
3.2.1	3-6	A relay with a detached cable-connected operator panel allows the installation of the relay itself in the low-voltage compartment and the installation of the operator panel separately in the door of the switchgear.

Listing of Key Information

**Key O&M Cost Point (Cont.)**

Emphasizes information that will reduce purchase, operating, or maintenance costs.

Referenced Section	Page Number	Key Point
3.3.2.2	3-12	The power consumption of numerical relays can be expected in the 0.04–0.10 VA range. This means that in many applications, the relay burden is negligible.
4.2.2	4-4	The automatic synchronizing relay provides jogging signals to the excitation control system (to raise or lower the machine voltage) and to the machine governor control (to increase or decrease the machine speed). The relay automatically jogs the machine into position for secure and repeatable closure free of any human error.
4.11.1	4-23	Multiple definite-time overcurrent and inverse-time characteristics are available in modern numerical relays. Numerical relays also provide the capability for the relay engineer to define custom curves for special applications.
4.14.1	4-31	New relay designs now include connections using numerical relay binary inputs and outputs wired to remote SPR or FPR contacts to monitor operation, capture fault events, and signal remote operation. This allows for station operators to respond more quickly and efficiently compared to older schemes where remote lockouts and switches were used to flag a pressure operation.
4.20-1.1	4-42	Unlike an electromechanical relay, a numerical relay does not require a complicated current transformer (CT) scheme to match the measured currents. Instead, the relay uses entered information about the protected equipment and the current transformers to calculate the matched currents from the measured currents. This permits a standard CT secondary connection to be adopted, assigning the relay the task of calculating the necessary phase shift adjustments.
5.1.2	5-3	The digital relays must be able to provide the user with information regarding a fault or event. The more accurate and accessible the information, the easier it is to analyze and make informed decisions to return a machine to service.
5.3.2	5-13	Because local and remote control can be integrated in numerical relays, tripping can be initiated using trip control switches located on the front panel of the relay to actuate the trip circuit or via the system interface protocol.
5.3.3.3	5-16	With the IRIG communication capability, multiple relays can be time-synchronized by using an IRIG B clock reference. This allows for comparison between multiple relay events and fault recordings without introducing timing errors.

**Key O&M Cost Point (Cont.)**

Emphasizes information that will reduce purchase, operating, or maintenance costs.

Referenced Section	Page Number	Key Point
6.1	6-1	As customers have added numerical relays, maintenance intervals have been extended due to the nature of the equipment design. Moving parts, contacts, coils, and drift problems have been virtually eliminated. The numerical relay has proven to be a reliable and accurate device; therefore, less maintenance is required.
6.3.2	6-4	Mechanical checks are practically nonexistent in the context of microprocessor relays.
6.3.5	6-6	Identifying inoperative relays (or relays that do not have the proper power supply or binary input voltages) early in an installation allows time for corrective action to be taken without impacting the overall project schedule.
6.3.7	6-8	The relay management software and the personal computer greatly reduce setup time and replace many types of test equipment (such as ammeters, voltmeters, and phase angle meters) that were used formerly to take in-service readings.
6.4	6-8	A typical interval for periodic maintenance for numerical relays is four to eight years.
6.4	6-8	Event logs and trip logs can be used to measure the relay performance after a fault occurs. If the relay performs within the design, the protection system owner may determine that the window for periodic maintenance can be shifted to a later schedule.
7.3.2	7-3	Numerical relay manufacturers provide relays with the capability of having multiple setting groups that can be applied locally at the relay (using automatic logic to switch for changing system conditions) or that can be applied remotely via a system interface (SCADA).
9.1	9-1	Numerical relays no longer require calibration. There is no way to adjust the pickup of the relay except through a software setting change or possibly through PC card link settings.
9.7	9-5	A simplistic approach to performance trending will often yield information that is as useful as the information that results from detailed analysis.
11.0	11-1	Multifunctional relays perform a valuable function—they consolidate protection functions (and in some instances controls) and reduce the cost and complexity of the overall application.
11.2	11-3	A digital relay can provide a diagnosis of its own internal hardware and software and can also monitor the connected system. Digital relays can monitor the health of the current transformers and voltage transformers.

Listing of Key Information**Key O&M Cost Point (Cont.)**

Emphasizes information that will reduce purchase, operating, or maintenance costs.

Referenced Section	Page Number	Key Point
12.1.5	12-4	With microprocessor relays, a user can specify the triggering of the fault record, the duration of the recording, and the type of recording (that is, raw data as measured by the relay or filtered data).
13.0	13-1	As an ever-increasing percentage of the overall protection control scheme is integrated into the relay, the possibility exists to extend the benefits of self diagnostics beyond the internal subsystems of the relay. Using binary inputs to provide the relay with information regarding the health status of the control scheme, it is possible to use microprocessor relay programmable logic control functions to detect and respond to external control scheme malfunctions.



Key Technical Point

Targets information that will lead to improved equipment reliability.

Referenced Section	Page Number	Key Point
1.1	1-2	Deterioration is much slower in numerical relays than in electromechanical relays because numerical relays are not affected by mechanical deterioration.
2.2	2-2	There are actually two classifications of microprocessor relays—the analog hybrid relay and the numerical relay.
2.2	2-3	A numeric (or numerical) relay digitally samples the incoming analog signals, converts them to a binary number, and passes them to a microprocessor chip where algorithms perform mathematics to measure the condition of the power system and to provide the protective (trip) functions.
2.2.1.1	2-4	Power supplies may be specified for many different voltage applications—both AC and DC.
2.2.1.8	2-6	The input/output (I/O) subsections provide a means for the numeric relay to communicate with the “outside world.”
2.2.2	2-10	Digital relays store fault and sequence-of-events operation information within the device after a trip occurs.
2.2.2	2-12	If a more detailed analysis is required after a trip operation, digital relays store detailed fault information that can be downloaded using the relay PC program.
3.1.1	3-1	Settings, annunciations, and waveform captures are saved even if supply voltage is lost to the relay. Internal batteries that are used commonly have a life span of 10 years. It is advisable to change these batteries prior to their end of life.
3.2.2	3-6	The chassis in a numerical relay is specially designed for protection from mechanical stress and electromagnetic fields.
3.3.2	3-11	Modern numerical relays are tested using the latest industry ANSI/IEEE and IEC standards to prove that they meet industry rating requirements.
3.3.3	3-12	Design testing is performed to validate that a particular relay's design, construction, and materials perform as expected and are adequate for use in the intended application.
4.1.1	4-1	The distance protection function on generators is used as a fast backup protection for the generator, extending up to approximately 70% into the unit transformer.

Listing of Key Information

**Key Technical Point (Cont.)**

Targets information that will lead to improved equipment reliability.

Referenced Section	Page Number	Key Point
4.3.2	4-8	Some models of modern microprocessor relays have integrated programmable logic controller functions. In these relays, the voltage values are available to measurement logic that allows the user to develop custom-built logic applications.
4.4.1.1	4-9	Power relay elements typically use voltage and current quantities that are essentially in-phase to detect real power or watts. Because they require watts (a calculated value) to make them operate, they are not a very fast means of fault detection.
4.9.1	4-18	When the digital relay is used to protect a motor, the start-time monitoring feature supplements the overload protection. Start-time monitoring protects the motor against the potential damage that might result from frequent starting or extended starting durations.
4.10.1.2	4-20	Microprocessor relays with integrated logic controller functions can utilize data gathered by the relay's thermal protection to control pumps and fans via user-defined logic and the output matrix.
4.10.2.1	4-22	Microprocessor relay thermal logic alarms and trip outputs can be blocked by providing a binary input during emergency starts.
4.11.1	4-24	For ease of time coordination with older electromechanical relays, reset characteristics provide the capability of using a reset characteristic that emulates the resetting of older electromechanical induction disks.
4.12.2	4-29	Some numerical relays also calculate the positive-sequence and negative-sequence system voltage. Therefore, the symmetrical components are also monitored and can be combined according to the user's requirements.
4.18.2	4-39	The microprocessor relay can be equipped with four (and as many as six) stages of over/under frequency.
4.20.1.1	4-42	Microprocessor relays offer the ability to implement multiple slopes in a single characteristic.
4.20.2	4-46	Microprocessor relays permit multiple slopes to be combined into a single relay. The use of multiple slopes allows a more sensitive slope setting when the currents are low and a higher slope when high currents are likely to cause CT saturation.
4.21.1	4-48	An error-free data transfer is the prerequisite for the proper operation of the protective system. Therefore, the accuracy of the data transfer is continuously monitored internally.



Key Technical Point (Cont.)

Targets information that will lead to improved equipment reliability.

Referenced Section	Page Number	Key Point
5.1.2	5-2	It is possible for a digital relay to distinguish between a fuse-fail condition and an actual short circuit that would look identical for a 21 relay.
5.1.2.1	5-3	Digital relays provide the platform to maximize dependability and security.
5.2.3.1	5-8	Numerical relay manufacturers use both ANSI/IEEE and IEC standards to test relay performance.
5.3.2	5-14	When using two binary inputs, malfunctions in the trip circuit can be detected under all circuit breaker conditions.
5.3.3.3	5-16	Many numerical relays now have the option to provide time-of-day information in synchronous form for data correlation with time.
6.3.3	6-5	User-created logic, which in older generations of relays was engineered and verified by the relay manufacturer in extensive factory model power system type tests, should be electrically tested to ensure proper operation.
6.5.3	6-9	The philosophy for testing the elements within a multifunctional relay varies. A thorough evaluation of each element should be performed on any new numerical relay product before it is installed on a system to check that each meets the owner's design criteria and stated tolerances.
6.5.4	6-10	Because numerical relays require no calibration, the functional check proves that the relay element outputs are operating the equipment and, therefore, are proving the overall scheme design. This test can be initialized by using a relay test set to activate the relay element or by using the relay configuration software commissioning tools.
8.2.2.1	8-3	After obtaining the test results, the CT ground should be restored. A good practice is to repeat the insulation test after replacing the CT ground to verify a reading of zero, thus confirming that the CT ground was indeed restored.
8.4.2	8-6	If a dedicated binary output (such as a spare contact) is used for testing, at least one test should be performed to the actual binary output contact used for external tripping
9.1	9-1	Today, relay maintenance philosophies emphasize testing the complete protection scheme versus the specific relay element to prove that the external controls and the primary equipment operate according to the scheme design and operating characteristics.

Listing of Key Information



Key Technical Point (Cont.)

Targets information that will lead to improved equipment reliability.

Referenced Section	Page Number	Key Point
9.2	9-2	Without self monitoring, the number of failed devices increases sharply with increasing service time. (For more information see Gerhard Ziegler's book entitled Numerical Distance Protection: Principles and Application.) With monitoring, the percentage of failed devices is reduced.
10.1.3	10-2	Climatic temperature variations affect numerical relays less than electromechanical relays.
13.3	13-4	Microprocessor relays have the necessary intelligence to monitor, detect, and respond to failures of the AC voltage input circuits.
13.3	13-4	Backup protection that does not rely upon healthy voltages should be available for emergency protection during loss of potential conditions.



Key Human Performance Point

Denotes information that requires personnel action or consideration in order to prevent injury or damage or to ease completion of the task.

Referenced Section	Page Number	Key Human Performance Points
2.2.2	2-7	The HMI typically has touch-pad keys for entering or retrieving relay data and a serial connection port for connecting a portable computer to perform operations using relay configuration software.
3.1.4	3-2	With respect to communication, particular emphasis has been placed on high levels of flexibility, data integrity, and the utilization of standards common in energy automation. The design of the communication modules provides the benefits of interchangeability in equipment, the potential for acceptance of future standards, and an increase in industry-wide knowledge of communication protocols.
3.2.4	3-8	Manufacturers provide free access to the control keys and frontal display; however, changing the settings and controlling the breakers and switches are password-protected tasks.
3.2.6	3-9	Information such as event messages, measured values, and the functional status of the device are provided via LEDs and a display screen (LCD) on the front panel.
3.3	3-9	Because protective relays may be required to operate in harsh environments, they are tested to meet a variety of standards related to mechanical, electrical, thermal, and seismic conditions.
4.2.1	4-3	To avoid damaging the generator unit when placing it on-line, highly secure synchronizing and/or automatic synchronizing relays are used to ensure that the frequency, voltage magnitude, and phase angle are properly matched before connecting the generator to the system.
4.3.2	4-7	When connected to three phase-to-ground voltages, the microprocessor relay is capable of calculating the phase-to-phase voltages as well as the positive, negative, and zero-sequence voltages.
4.10.2.1	4-22	The microprocessor relay uses the measured current and the thermal time constant data supplied with the protected equipment to compute the temperature rise according to a thermal model.
4.15.1	4-32	The methods of stator ground-fault protection using 60 Hz voltage or current are capable of providing protection for only 90–95% of the stator winding. Third harmonic voltage schemes (27/59) and low-frequency injection schemes (64G) are capable of achieving 100% percent stator ground protection.
4.19.2	4-40	Virtual lockouts may be integrated into the microprocessor relay using the programmable logic controller feature of the relays.

Listing of Key Information

**Key Human Performance Point (Cont.)**

Denotes information that requires personnel action or consideration in order to prevent injury or damage or to ease completion of the task.

Referenced Section	Page Number	Key Human Performance Points
4.21.1	4-48	The differential protection system requires a protective device as well as a set of current transformers at either end of the protected zone. The devices located at the ends of the protected zone exchange measured information via interfaces using assigned communication links (usually fiber-optic cables) or a communication network.
5.0	5-1	By understanding the general design philosophy and approach of protective relaying, the importance of correctly performed maintenance can be more completely appreciated.
5.1.2.3	5-4	The physical behavior of electromechanical relays simulated in a digital signal microprocessor is called an algorithm. The relay can monitor itself, utilize self diagnostics, and alarm when it is not providing protection.
5.3.1.1	5-12	Saturation of a CT can prevent a protective relay from operating properly. For this reason, a CT must be carefully sized so that it will perform properly for the maximum expected fault current.
5.3.3	5-14	Numerical relay communication to the outside world can include relay to personal computer, relay, power-line carrier, SCADA interface, and satellite communications. Communication interfaces are becoming increasingly important for the efficient and economic operation of generating stations and networks.
6.1	6-2	Most manufacturers state that no maintenance is required on their numerical relays. However, this does not eliminate the need to check the overall operation and to verify that the primary equipment operates reliably.
6.3	6-3	Numeric relays have revolutionized all aspects of protection and control. Testing is no exception. There is room for much innovation in developing test strategies and there is not likely to be a consensus for some time to come. Practices will vary from utility to utility.
6.3.5	6-6	Microprocessor relays allow the user to connect locally or remotely with a personal computer and to electronically force output contacts to change states. This method can be used to verify the operation of external devices such as circuit breakers and to confirm the control scheme wiring external to the relay.
6.3.6	6-6	The microprocessor relay provides a great deal of information for local retrieval or for data transmission including operational indications and alarms, operational measured values and metered values, fault recording, and oscillography data.


Key Human Performance Point (Cont.)

Denotes information that requires personnel action or consideration in order to prevent injury or damage or to ease completion of the task.

Referenced Section	Page Number	Key Human Performance Points (Contl)
6.3.6	6-7	Most of the difficulties in electrically testing microprocessor relays are actually errors in the test connections or methods.
7.1	7-1	Failure to enable a relay program following the use of a temporary program specifically designed to test a subset of the functions in the overall protection scheme is a common mistake.
7.3.2	7-3	One technique used so that the master file does not get modified when maintenance is required is to create an alternate setting file. This file is developed from the master file to use specifically for testing the various elements within the relay.
8.1.1	8-2	Numeric relays are more difficult to test than previous generations of relays because they have the intelligence to recognize the dynamic states and failures of the measurement inputs.
8.1.2	8-2	Test methods may require that certain measurement input features of the relay's self diagnostics (such as fuse failure or current anomalies) be temporarily defeated.
9.6	9-5	An area of training that should not be overlooked involves test equipment and personal computers. Protective relay test sets are very specialized equipment. Considerable knowledge is required to operate them correctly. Maintenance personnel must fully understand and know how to use, and recognize the limitations of, the test equipment, personal computers, and any associated relay configuration and evaluation software.
11.0	11-1	Self monitoring is much more than the function of testing and monitoring the A/D converter, software, memory, and hardware. It is the first step in the self-monitoring process and it is also a test to make sure that everything in and about the relay installation is correct.

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ORGANIZATION(S) THAT PREPARED THIS DOCUMENT

EPRI

RESUME

Objectifs

- Fournir une compréhension étendue sur la maintenance des relais de protection numériques
- Fournir au personnel de maintenance, de l'ingénierie, de la conduite les connaissances et les conseils sur la façon dont développer les tests, l'étalonnage, et les contrôle adéquats de post-installation et de poste-maintenance des relais de protection numérique.

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レポートの概要

目的

- リレー設計に対する明確な理解を与え、デジタル保護リレーの適用と保全に関する考察を与えること。
- プラントの保全、エンジニアリング、運転に関わる職員に対し、適切な、テスト、キャリブレーション、据付け後テスト、及び保全後テストを立案する方法についての知識およびガイドを与えること。

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DIVULGAR EL RESUMEN

Objetivos

- Para ofrecer un entendimiento claro de esquemas de relés y consideraciones en las aplicaciones y mantenimiento de relés protectivo numéricos
- Para ofrecer mantenimiento en planta, ingeniería y operaciones de personal con conocimiento y guía en como crear pruebas adecuadas, calibración, y pruebas de poste-instalación y poste-mantenimiento

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