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Revision Memo

10/04 Highlights of this revision are:

1. Added more IEEE and IEC reference standards.
2. Added transfer blocking requirement for high-resistance grounded substations.
3. Clarified documentation requirements in Microprocessor-Based Relay section.
4. Stressed need to test ground fault relays at commissioning.
5. Added calculation of saturation in Current Transformer section and mentioned 'overdimensioning' of CT's.
6. Recommended 2 out of 3 tripping for critical motor undervoltage protection.
7. Added section on potential transformer fusing.
8. Added requirement for relay narrative to contractor relay documentation.
9. Recommended minimum pickup tripping time for motor 50 GS and 50N relays.
10. Added relay discussion for spot-network substations.

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1 SCOPE

This section outlines our approach to system and equipment protective relaying from the power source, as defined in [DP XXX-C](#), to the loads.

Design details of relays and calibration procedures are not covered. For this information, reference should be made to the manufacturer's instruction bulletins for each particular relay. Startup, commissioning and maintenance of protective relaying are covered in the "Electrical Equipment Acceptance and Maintenance Manual" TMEE064. Specialized protective relaying, such as for instruments and d-c circuits, are not included.

2 REFERENCES

2.1 GLOBAL PRACTICES

GP 16-02-01	Power System Design
GP 16-04-01	Grounding and Overvoltage Protection
GP 16-07-01	Motor Application
GP 16-09-03	Synchronous Generators
GP 16-10-01	Power Transformers
GP 16-11-01	Neutral Grounding Resistors
GP 16-12-01	Switchgear, Control Centers, and Bus Duct
GP 16-12-02	Control of Secondary Selective Substations with Automatic Transfer
GP 16-13-01	Field Installation and Testing of Electrical Equipment

2.2 OTHER LITERATURE

ABB, *Protective Relaying Theory and Applications*

ANSI/IEEE, *IEEE Guide for Protective Relay Application to Power System Busses*, C37.97-2000

ANSI / IEEE, *IEEE Guide for Protective Relay Applications to Power Transformers*, C37.91-2000

ANSI / IEEE, *IEEE Guide for AC Motor Protection*, C37.96-2000

ANSI / IEEE, *IEEE Guide for AC Generator Protection*, C37.102-1996

ANSI / IEEE, *IEEE Guide for Protective Relay Applications to Transmission Lines*, C37.113

ANSI / IEEE, *IEEE Guide for Application of Current Transformers Used for Protective Relaying Purposes*, C37.110-1996

ANSI / IEEE, *IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems*, Std 242-1986

IEEE Transactions, *Allowing for Decrement and Fault Voltage in Industrial Relaying*, IGA March/April 1965, pp. 130 - 139

IEC 60044-1 Instrument transformers - Part 1: *Current transformers*

IEC 60044-6 Instrument Transformers - Part 6: *Requirements for Protective Current Transformers for Transient Performance*

IEC 60255-3 Electrical Relays - Part 3: *Single Input Energizing Quantity Measuring Relays with Dependent or Independent Time*

IEC 60269-1, -2, *Low-Voltage Fuses*

Beeman, D., *Industrial Power Systems Data Book*, published by McGraw-Hill

GEC Measurements, *Protective Relays Application Guide (PRAG)*, GEC, U.K.

C.Russell Mason, *Art and Science of Protective Relaying*, <http://www.geindustrial.com/pm/notes/artsci/index.htm>

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3 BACKGROUND

Protective relaying is essential to maintain the integrity of the electrical system during a fault or other abnormal conditions. Even a well designed and maintained system can perform poorly if the protective relaying is not properly applied.

During normal operation of an electrical system, the protective relaying is dormant and does not contribute to the reliability, hence deficiencies, such as defective relays, disconnected wiring, design errors, or incorrect settings, can go undetected for a long time (maybe years). However, when there is a fault or other abnormal condition on the electrical system, it is essential that the faulty equipment or circuit be disconnected by the protective relaying in the shortest possible time, otherwise the whole system may collapse.

Because the protective relaying is so important and because we accept that nothing can be perfect, we apply additional protection to back-up the first line protection that will:

- Isolate the faulty equipment a short time after the primary relaying should have operated and/or
- Isolate the faulty equipment by disconnecting the supply to it at a point further from the fault than the primary protection would have done.

Protective relaying should be designed to cover the worst possible scenario to fulfill its function of protecting the electrical system. This entails checking that it will operate correctly for all system configurations that are possible.

In some unusual cases it may be necessary to sacrifice coordination to achieve faster clearing times for example [Figure 1](#) and [2](#) of GP16-02-01. These cases should be limited to an absolute minimum and the reasons for it should be documented in the design notes for the project.

4 DEFINITIONS

Burden

The term used for the electrical load on the secondary of a current transformer, including the resistance of the secondary winding. The burden is either expressed in ohms (with resistance and reactance components), or in volt-amperes at a specified power factor and current (usually the rated amperes of the device or the relay tap).

Device Numbers

The American numbering system for electrical devices is in the section entitled [IEEE STANDARD ELECTRICAL DEVICE FUNCTION NUMBERS](#).

Fault

As used herein, a fault is a short circuit that causes a very high current flow, which is generally considerably in excess of rated current for the equipment or circuit. Fault currents are high enough to operate a protective device to isolate the "fault" within two seconds. **GP 16-02-01** defines the distinction between an overload and a fault, as follows: "Overload vs. fault protection, as used in discussing selectivity, refers to the parts of relay, device, or fuse time-current characteristics respectively above and below two seconds."

High-Resistance Neutral Grounding

A system where the ground fault current is limited to such a low value that it can flow for several hours without damage to equipment. Ground relaying is not fitted on such a system except for ground fault detection alarm. Ground fault current is normally limited to 10 amperes maximum, but no more than 5 amperes is preferred. To avoid transient overvoltages, the ground fault current through the resistor must be equal to or slightly greater than 3 times the future maximum per-phase charging current to ground of the system to which it is directly connected; i.e., not including parts of the system separated from the ground source by isolation transformers that are open circuits in the zero sequence network. This makes the resistor ground fault current about equal to the capacitive ground fault current, and makes the total ground fault current about 1.414 times the resistor's fault current. Thus the future maximum per-phase charging current to ground of the (zero sequence isolated) system can be no more than 2.35 A (preferably 1.18 A) for a high resistance grounding application. This usually limits the application of high resistance grounding to a generator with a unit transformer, or a small low-voltage system. If a double-ended substation is

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involved, ground fault detectors must be employed in order to block manual and automatic transfer, when ground faults are present on both busses, to prevent a phase-to-phase fault at the moment of transfer.

Knee Point (Knee Voltage)

The knee point is that point of a current transformer excitation curve at which a further increase of 10% of secondary e.m.f. would require an increment of exciting current of 50%. See [Figure 1](#). For most relaying applications, acceptable accuracy is obtained only when operation is below the knee point.

Low-Resistance Neutral Grounding

A system where the ground fault current is limited by a resistor connected between the system neutral and ground to reduce damage to equipment by ground faults, but where the current is high enough to operate ground protective relays reliably. Per **GP 16-02-01**, the neutral resistor must be sized to produce a ground fault current at least 15 times the lowest reliable operating current of the least sensitive outgoing feeder ground relay, and at least 5 times the lowest reliable operating current of bus ground relaying. To avoid any possibility of the ground fault current being low enough to cause transient overvoltages greater than 2.5 times the normal crest voltage to ground, the ground fault current should be at least 6.6% of the maximum 3-phase fault current. This ground-fault magnitude basis yields roughly the same order of magnitude ground-fault current as the 5-times rule in the previous sentence.

Overload

A current that is in excess of the rated value specified for a piece of equipment for the conditions under which it is operating, but not a high enough current to be considered a "fault." Examples of overloads are a pump with a higher viscosity fluid than design, and a transformer with too many loads connected.

Overreach (Transient Overreach)

Applied to instantaneous overcurrent relays and impedance relays, where for various reasons a relay operates for faults beyond the zone it was intended to cover (reach); i.e., the relay overreaches (see faults farther away than intended by the relay setting). Overreach of an instantaneous overcurrent (50) relay relates to the relay's sensitivity to asymmetrical amperes. A 50 relay sensitive to d-c offset can operate even though the symmetrical value of an offset current is below the relay's symmetrical setting. The typical application of overreach in our operations is to set a 50 relay on a transformer primary so it does NOT operate for a fault on the transformer secondary. To achieve this, the relay must be set above a multiple of the transformer-secondary symmetrical rms fault current (I_F) as seen by the relay. The multiple accounts for the instantaneous relay's overreach. In practice, a 50 relay that is fully sensitive to dc offset is set at about 190% to 200% of the reflected secondary-side symmetrical fault level; while a 50 relay with low overreach is set about 10% to 20% higher than I_F times the quantity $(1 + \% \text{ overreach}/100)$, where the % overreach is defined by the relay manufacturer, such as in [Figure 6](#).

Overtravel (Overshoot) Time

A time interval associated with time-delayed overcurrent relays related to the relay completing its operation even though the input to the relay is removed prior to the specified operating time. For example, if for a given current, the relay operates in 0.8 seconds, but the relay operates even though the input current lasts only 0.75 seconds, the overtravel time is 50 milliseconds. The maximum overtravel time of an upstream relay must be factored into the discrimination interval between this upstream relay and a downstream overcurrent device to ensure that the upstream device does not operate when the downstream device correctly interrupts the overcurrent. The overshoot time of a relay is provided by the relay manufacturer, and can be as low as 30 milliseconds for solid state relays, and as high as 100 milliseconds for electromechanical relays.

Secondary-Selective Substation

A secondary selective substation has two busses, each supplied by a normally-closed incoming circuit breaker, and connected together by a normally-open bus tie breaker. In our designs per **GP 16-12-02**, the loss of supply upstream of one incoming breaker results in automatic opening of that incoming breaker, followed by closing of the tie breaker after the "dead" bus' residual voltage has decayed to a safe level.

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Selectivity / Coordination/Discrimination

Selectivity describes a protective system that has been designed and adjusted such that the protective device nearest to the fault operates first to clear the fault, and its setting allows an adequate margin of safety so that a protective device farther from the fault does not operate for the same fault. As the relay coordination procedure commences at the load and works back to the power source, we generally say an upstream device is selective with a downstream device.

Spot-Network Substation

A spot network substation has a main bus (with or without a normally-closed tie breaker), which is supplied by two normally-closed incoming breakers. Tripping of one incoming breaker due to an upstream fault leaves the entire substation load on the other incomer without the transfer of load required for secondary-selective substations. A relayed tie breaker is provided when it is important to maintain supply to the loads on one of the busses for a bus fault or uncleared feeder fault on the other bus.

5 PROTECTIVE DEVICE TYPES AND APPLICATION

5.1 DIRECT ACTING TRIPS

A direct-acting-trip circuit breaker uses abnormally high current flowing into the breaker to initiate a time-delayed or instantaneous response which causes a direct acting operating mechanism to mechanically trip the breaker, without the need for external current transformers and relays. The time-current characteristic of a direct-acting-trip breaker is a band, the upper boundary of which indicates the maximum total clearing time of the breaker for a given current, while the lower boundary indicates the minimum clearing time. Direct acting trip units may be electromechanical (thermal-magnetic) or solid-state electronic. They are used in molded-case/insulated-case circuit breakers; and they are also used in low-voltage switchgear circuit breakers in the following applications:

- For all outgoing feeder breakers, such as to MCCs, TAPCs, transformers, and typically to motors that would require larger than a size 4 starter. For motor feeders, the direct acting trip of a switchgear circuit breaker must be backed up with a thermal-overload (49) relay in one phase.
- With Owner's Engineer approval, for the 51 and 51N functions of secondary-selective incoming breakers. The 51N ground fault function is available in direct acting trips with internal current transformers. The 50 and 50N functions must be relays.
- Incoming breakers in radial and primary selective substations.
- Incoming and outgoing circuit breakers in conjunction with auto-reclose.

This last application, which we have in use in Europe, permits instantaneous tripping on both incoming and outgoing circuit breakers. The circuit breakers have a one shot auto-reclose if immediately upstream of the load instantaneous protection, and two shot auto-reclose if located upstream of a one shot auto-reclose circuit breaker. In this application, the circuit breakers are usually current limiting.

GP 16-12-01 states: "Selective reclosure for current limiting breakers is acceptable only if approved by the Owner's Engineer." If this is employed, the relaying downstream of the circuit breaker with the instantaneous direct acting trip must be arranged for the motors to "ride through" the disturbance or auto restart.

5.2 FUSES

Fuses are simple and reliable fault interrupters. They are less expensive than circuit breakers, but they cannot be re-used and cannot be tested. The types of fuses most often used in our installations are current limiting, which means that above a given fault level, the fuse will interrupt the fault current before it reaches its first peak. By limiting the magnitude and duration of fault current, current-limiting fuses minimize stress and damage to equipment, and can allow use of less expensive equipment downstream of the fuse. The typical use of current-limiting fuses is in motor starters, in general-purpose feeder protection, and in the protection of transformers (usually smaller than 500 kVA in ExxonMobil designs).

When a current-limiting fuse operates for currents in its current-limiting range, it can be characterized by its peak let-through current (see [Figure 2](#)), and by its minimum melting and total clearing I^2t characteristics (discussed below).

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When a current-limiting fuse operates for currents below its current-limiting range, it can be characterized by its time-current-characteristic (TCC) curves, which are similar to those of other fuses.

The **melting time** of a fuse (sometimes referred to as pre-arcing time) is the interval from the inception of a given fault current up to the time that melting of the fuse element is sufficient for arcing to just begin.

The **minimum melting curve** provided by the fuse manufacturer shows the least amount of time it takes for a given current to melt an **unloaded fuse** in its non-current-limiting range of operation. The fuse manufacturer provides information on how to adjust the minimum-melt curve to account for preloading and other variables. The adjustment is current-based and moves the minimum-melt curve to the left.

The minimum melting curve is used to coordinate the fuse with downstream protective devices for fault levels below the fuse's current limiting threshold. The minimum melting curve is also used to avoid fuse melting during motor starting or transformer energization. See the discussion of I^2t below for current limiting operation.

The **total clearing time** of a fuse is the interval from the inception of the fault to the time the fault is completely interrupted.

The **total clearing curve** provided by the fuse manufacturer shows the maximum time it takes the fuse to completely clear any given constant fault current in the fuse's non-current-limiting range of operation.

The fuse's total clearing time curve is used to coordinate upstream time-delayed protective devices with the fuse for currents less than the fuse's current-limiting threshold. See the discussion of I^2t below for current limiting operation.

Average melting curves are sometimes provided by a fuse manufacturer. These curves have a plus or minus tolerance of 10% on current for any given time. Thus the minimum melting curve is 10% lower in current than the average melting curve, and the maximum melting curve is 10% higher. For times greater than about 0.1 second, the maximum melting curve is essentially the same as the total clearing curve. If coordination with an upstream time-delayed device were questionable in the time between 0.1 second and 0.01 second, the estimated arcing time would have to be added to the maximum melting curve to approximate the total clearing time.

For fault clearing times of one half cycle or less (e.g., below 0.01 second at 50 Hz), the peak let-through or I^2t characteristics of the current-limiting fuse should be used.

Total clearing I^2t and minimum melting I^2t data can be used for coordinating fuses in their current-limiting range. Two current limiting fuses connected in series coordinate when the downstream fuse's total clearing I^2t is less than the upstream fuse's minimum melting I^2t . [Figures 22 and 43](#) show I^2t data versus fuse sizes.

The ratios of fuse sizes required for coordination are provided in manufacturers' literature in the form of tables showing the size ratio of upstream to downstream fuses that will guarantee coordination. The ratio will be a constant for fuses of the same type (e.g., 2:1), but an upstream fuse of one type may need to be anywhere from 2 times to 8 times the size of a downstream fuse of a different type, in accordance with manufacturers' ratio data. If closer fuse sizing (than indicated by the ratio tables) is desired for a system coordination study, then the other fuse data discussed above should be used.

Peak let-through fuse data can be used to coordinate an upstream instantaneous relay with a downstream current limiting fuse. Coordination is achieved if the fuse's peak let-through current times 0.707 is less than the rms pick-up setting of the upstream instantaneous unit. This current limitation effectively ensures that the instantaneous device does not see enough energy to operate. [Figure 23](#) illustrates the half cycle worth of energy it takes to just cause pickup of an instantaneous relay. [Figure 24](#) illustrates the pickup-energy portion of a current higher than the relay's pickup current. It can be seen in [Figure 25](#) that a current-limiting fuse will not allow the relay to see enough energy to pick up if the peak let-through of the fuse is less than the peak of the relay's rms pickup.

Peak let-through data is presented as a function of the available symmetrical rms short-circuit current as shown in [Figure 26](#). The line AB in [Figure 26](#) represents the boundary between current limitation and non current limitation. The slope of line AB could be anything from 1.414, which is the peak of a symmetrical current, up to 2.828, which is the peak of a fully offset current. For peak let-through determination, the slope of line AB is a function of the fault power factor, and is often drawn with a slope of about 2.6. A second line AB with a slope of 1.414 can be drawn for a short cut determination of the symmetrical rms current that has the same peak value as the fuse's peak let-through. For example, if for a given situation, the peak let-through current is 14,140 amperes on the y-axis, the corresponding "equivalent" symmetrical rms value per the 1.414-sloped line is 10,000 amperes on the x-axis.

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Explosive fuses are current limiting fuses that achieve fault-current interruption with the help of electronically-triggered explosive charges. Such fuses (sometimes called smart fuses) are used where fault current limitation is required, but where the normal operating current is too high for conventional current-limiting fuses. Explosive fuses can be used to split a system with inadequately rated interrupting equipment into two lower fault-level systems, or to limit the fault current from a specific source by opening its circuit or by opening a bypass around a current-limiting reactor. Such applications may be considered when a system is expanded beyond its equipment fault rating and the addition of current limiting reactors would present unacceptable operating voltage problems.

Some fuses have indicators that make it easy to detect a "blown" fuse, and striker pins that are released when the fuse "blows". Striker pins are used to trigger a mechanism that opens a switching device to isolate all three phases, thereby preventing single phasing.

The rating of a fuse is the current that it can carry continuously without deterioration. However, transient currents and temperature cycling can "age" a fuse; therefore some manufacturers recommend periodic replacement (every five or ten years) to avoid maloperation. The current at which a fuse will start to melt is in the order of 120% to 150% of its rating.

A list of I.E.C. recommended fuse ratings for low voltage is given in [Table 1](#).

For our purposes, fuses can be divided into three main categories, as follows:

CATEGORY	TYPICAL APPLICATION	CURRENT LET-THRU
Slow Blow	Rural Distribution Overhead Lines	System Peak
General Purpose	Industry (90% of all fuses)	Current Limiting
Ultra Rapid	Inverter Loads/Instruments	Current Limiting

The operation of a current limiting fuse in its current-limiting zone is shown in [Figure 2](#) where the actual peak current that flows (let-through) is considerably less than what would have flowed if it had not been interrupted by the fuse. Fuse manufacturers provide peak let-through curves which show peak current as a function of fuse size and available fault current.

Fuses have many sophisticated features to cater for transformer inrush, motor starting, etc., so much so that in every case for the final design, the manufacture's recommendations should be followed as to which type of fuse is used. Additionally, the data for the actual fuses used should be available for the relay coordination study.

In summary, always use the manufacturer's recommendations in selecting the type of fuse, and for relay coordination use the data pertaining to the particular fuse that is used. The following data are generally required from the manufacturer:

- Pre-arcing (minimum melting) curves - to discriminate with motor starting and transformer inrush currents, and with downstream overcurrent devices for a fault current below the fuse's current-limiting threshold.
- Total clearing curves - to discriminate with upstream time-delayed overcurrent devices (not including current-limiting fuses).
- Peak let-through curves - to discriminate with instantaneous relays.
- Current squared time (I^2t) curves for pre-arcing and total clearing, or fuse selectivity-ratio data, to discriminate between fuses.

5.3 RELAYS - GENERAL

Protective relays use inputs of current or voltage, or a combination of both, and compare these inputs to a threshold quantity which is normally called the pickup (or the setting). Once the threshold is passed in the operating direction (e.g., high current, low voltage, low fault-impedance, etc.), the relay will either operate almost immediately (instantaneous relaying), or with a time delay. The time delay is either fixed (definite time), or is a inverse function of the measured quantity; e.g., for an overcurrent relay, the higher the current, the shorter the time delay. If the magnitude of the measured quantity returns to a non-operating level before the timing has gone too far, the relay will reset without operating. In addition to measurement, comparison and time delay, some protective relays determine and act upon the direction of the measured quantity; some perform filtering functions such as deriving sequence network quantities; and some can retain event information and perform self-checking.

Electromechanical relays use magnetic attraction, magnetic induction, or thermal heating to achieve operation.

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Solid state relays use low-power resistors, capacitors, and semi-conductor devices arranged into logic circuits to achieve operation.

Microprocessor-based relays use digital sampling and processing technology to achieve operation. They can also store event information, do self-checking, and can communicate with external digital equipment.

Solid state and microprocessor-based relays have many advantages over electromechanical relays, and have become the relay-type of choice, especially for applications outside of small low-voltage-motor starters.

5.4 MICROPROCESSOR-BASED RELAYS

In recent years, there has been an increasing trend toward the use of microprocessor-based relays. Some of the reasons for the shift from electro-mechanical relays to microprocessor based relays includes:

- Microprocessor-based relays are more accurate and more repeatable than equivalent electro-mechanical relays.
- Equivalent functions can be obtained at lower cost because a single microprocessor-based relay can perform the functions of many electro-mechanical relays. Because one device is replacing several, installation costs are greatly reduced, particularly if reduced space requirements result in fewer panels.
- Some functions, operating characteristics, or communication capabilities which are not possible with electro-mechanical relays can be done with microprocessor-based relays.

Despite these advantages, microprocessor-based relays raise a number of concerns. The main one is the possibility of total failure of the protective system due to failure of one component on the critical path, such as the power supply. Previously, failure of one discrete relay resulted in loss of only one protection function on one phase. The remaining protection functions on the faulted phase and all the protection functions on the other two phases still provided protection. With the multi-function microprocessor-based relay, a common mode failure can result in the loss of all the protection functions on all three phases. The counter argument is that microprocessor-based relays have diagnostics that provide an alarm if there is a malfunction. With electro-mechanical relays, a malfunction is not discovered until the relay is required to operate.

To overcome this concern, a second multi-function relay is sometimes provided for redundancy for large critical equipment such as generators and main transformers. Generally, the second relay would be from a different manufacturer to preclude the possibility of a common mode failure. Adding a second relay doubles the probability of a false trip. As long as backup relaying exists, a 2oo2 tripping connection, with the watchdog contact bypassing the failed relay's trip contact, is a more secure alternative than 1oo2 tripping.

Another option is to divide various protection functions into two or more relays. For example, the differential protection for a generator may be housed in an independent relay separate from the other protection functions; i.e., overcurrent, under voltage, loss of excitation, etc.

Another problem that has surfaced with microprocessor-based relays is that the complexity of setting these relays has resulted in incorrect settings. The instruction manual for an electro-mechanical relay is in the order of 10-15 pages while the instruction manual for a multi-function microprocessor based relay are usually more than 200 pages. These manuals can be difficult to read and sometimes the instructions are confusing. In some cases, it is difficult to determine the factory default settings. Extra care is required in determining the required settings and transmitting the information to field personnel who will do the setting and testing of the relays.

Other recommendations when applying microprocessor-based relays includes the following:

- Be sure that the relay watchdog timer contact sends an alarm signal to the substation alarm panel to warn of relay failure.
- Use only the relay protection functions that are needed. Do not use all the functions included with the relay just because they are available. Be sure the unneeded functions have been disabled by indicating this on the setting sheets and confirming with a printout from the relay. A computer file of the relay's settings is recommended when the total amount of data to be entered into the relay exceeds 1 full page - this avoids errors associated with manual data entry.
- Understand, define and set up the diagnostic and fault recording information available in the relay.
- The substation battery supply needs to have filters to insure that if the battery is disconnected for any reason, the ripple on the rectifier output does not damage the relays.

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- Particular attention must be paid to grounding and paths for transient voltages/currents to these relays such as through RTD or DC power supplies. Manufacturer's grounding and isolation recommendations should be carefully followed.
- Institute a "management of change" procedure to handle changes to relay parameter settings. Document the reason why the change is being made. Record (or download) as-found settings before making the change and document any discrepancy between the found setting and the expected one.
- Develop a logic diagram ([Figure 46](#)) which will be kept in the permanent settings files representing the interaction between the relay's measurement units, digital inputs and the trip/alarm outputs.
- Documentation of microprocessor relay settings requires special forms (unlike the form shown in [Figure 31](#)) due to the number of parameters involved. Computer disk copies of settings should be used to minimize errors resulting from manual data entry. The user must develop a long term file retention system for this critical documentation.
- Record the firmware revision of every relay as part of the settings sheet. Upgrade firmware *only* when necessary. Repeat relay commissioning tests when upgrading firmware to be sure the existing settings are compatible with the new firmware.
- Generate a hard copy of any programmed logic inside the relay and add to switchgear wiring diagrams. The relay should not be a "black box" on the switchgear diagrams.

5.5 RELAYS - DEVICE DESCRIPTIONS

Most of the relays we use in our plants are discussed below.

5.6 TIME DELAY RELAYS (2) AND (62)

We use time delay relays extensively in protective relaying and in motor reacceleration circuits. These are relatively simple relays with some form of timing device which delays contact operation when the relay is activated. The relays must ensure that the timer can remain dormant for long periods and then operate correctly when required. Timers are either pneumatic, mechanical, or solid state.

5.7 DISTANCE RELAYS (21)

Relays that measure some form of impedance, often along a transmission line, are called distance relays. The terminology for distance relays depends on how the relay uses its current and voltage inputs. Relays that effectively operate on the magnitude of a measured impedance, but not its direction, are called impedance relays; while relays that operate on the magnitude of reactance are called reactance relays. Both of these are normally supervised by a directional relay. Relays that measure impedance magnitude but are inherently directional are called admittance or mho relays. How the current and voltage transformers should be connected for various applications, and how to interpret what each relay sees for unbalanced faults is beyond the scope of this Design Practice. The relay instruction manual should be consulted for any given application.

When the measured impedance is less than the preset value, the relay operates. The main applications are on utility networks where they may be the most common relay in use. Some knowledge of their modes of operation is essential to us when we must coordinate our protective relaying with that of the local utility to which we are connected. We have the potential to use distance relaying instead of 51V relaying for generators that are stepped up directly to a utility transmission line protected by distance relaying.

An application of distance/impedance relaying is shown in [Figure 19](#) which shows diagrammatically the operating zones and times for one relay on a utility transmission or distribution network. Each of the other circuit breakers shown in [Figure 19](#) will have a similar relay "looking" into its line (i.e., away from its local busbar) with settings on the same basis as the one shown.

The first stage of protection "looks" at 80% of its line and for a fault in that zone will operate within 0.1 seconds. The second stage looks at 120% of its line and will operate in 0.5 seconds. The third stage (which may be non-directional) is looking at 200% of the line impedance in both directions and has an operating time of 1.5 seconds. At Busbar B there will be a directional relay on the line between bus A and B looking back towards bus A.

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This is only a typical scheme; actual applications will vary considerably. For a fault in the middle 40% of any line, the breakers at both ends will be tripped by the first stage of the protection to isolate the fault. For a fault in the 20% at either end of the line, the circuit breaker nearest the fault will be tripped by the first stage of protection and the circuit breaker at the end of the line farthest from the fault will be tripped by the second stage of protection. If the circuit breaker nearest the fault fails to trip, its busbar will be isolated by the second stage of the feeder breakers supplying the bus. Likewise, the third stage of protection provides back-up protection for a breaker that fails to clear a fault at the remote end of the line.

If supply to our facilities is derived from Busbar A, we know that we can see a reduced voltage for 0.5 seconds plus breaker clearing time for distant faults cleared by the second stage of the first line protection.

When a line segment protected by a distance relay has a second source of fault current connected between the relay and a fault, the impedance relay sees a higher apparent impedance than when the second source is disconnected. A diagram and formula (Equation 12) for the higher apparent impedance is presented near the end of this Design Practice in the section entitled CONVERSIONS AND CALCULATIONS under the side heading Determining Distance Relay Apparent Impedance, Z_R , Due to Infeed Current. An impedance relay that should not see beyond a given distance must be set with the second source disconnected. The relay will not protect as much of the line with the second source in, as it does when the second source is out. In effect the relay underreaches its setting when the second fault-current source is connected.

5.8 VOLTS / HERTZ RELAYING (24) - OVEREXCITATION PROTECTION

Overexcitation (and overheating) of the magnetic core of generators and fully loaded transformers begins when the ratio of per unit voltage to per unit frequency exceeds 1.05, and increases rapidly as the volts/hertz ratio increases. Some form of volts/hertz protection is needed for generators - either in the form of a volts/hertz limiter in the exciter control system or volts/hertz relaying, or both. Volts/hertz relaying is needed for transformers that could be subjected to overexcitation. Where volts/hertz relaying is applied, an alarm function should be provided with enough lead time to allow operator intervention before tripping occurs.

5.9 SYNCHRONIZING RELAYS (25)

Synchronizing relays can be divided into two main groups: system synchronizing check relays, and generator synchronizing relays. The former are used to block paralleling two parts of an electrical system that are not synchronized. They are relatively slow speed and are not used for generator synchronizing on machines above about 500 kVA.

Generator synchronizing relays are the main component of equipment packages which function to insure that the system and incoming machine-voltage magnitude, phase angle and slip frequency are within acceptable limits relative to the system voltage at the moment the generator breaker closes to synchronize the machine to the system.

Generator synchronizing relays can be further divided into three types:

- Machine out of synchronism blocking relays
- Semi-automatic synchronizing relays
- Automatic synchronizing relays

Machine out of synchronism blocking relays will prevent closing of a generator breaker when the machine voltage vector is outside the preset limits, as compared to the system voltage vector. This relay is more complex than the system synchronizing check relay, since it takes into account the velocity of the machine voltage vector (phase angle and slip frequency) with respect to the system vector as one does when synchronizing manually.

Automatic synchronizing relays are equipment packages which adjust the driver governor and generator excitation, and close the generator breaker when the generator voltage matches the system voltage within acceptable limits. Some automatic synchronizing relays are also equipped to load the generator after synchronizing. Semi-automatic synchronizing relays require the operator to close the breaker using the control switch.

We use all four types of synchronizing relays. The system synchronizing check relays are used in the automatic transfer circuit (see **GP 16-12-02**) to prevent an operator from paralleling two infeeds that are out of synchronism when making a manual transfer. Also, we usually use one of the three machine synchronizing relays on our generators to facilitate proper synchronizing and avoid operator errors, even though synchronizing a generator can be done manually using the synchroscope and voltmeters which are always provided.

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5.10 TEMPERATURE RELAYS (26)

These relays are temperature measuring devices with contacts that operate when a preset temperature is reached. We fit these to all our power transformers (see **GP 16-10-01**) where the relay takes the form of a dial-type thermometer for indicating the top of the liquid temperature. The relay has two hands, one showing oil temperature at time of reading and the second showing maximum temperature reached since last resetting.

For our applications, the thermometer must have hermetically-sealed, normally-closed alarm contacts set to open at the maximum self-cooled operating temperature of the transformer.

Transformers are normally supplied with temperature relays but the contacts are usually open to the atmosphere. Manufacturers generally meet our requirements by fitting mercury bottle switches.

The hermetically sealed contacts are required for two reasons:

- Transformers are usually located at the very edge of Division 2 areas.
- Bare contacts that will normally never operate can deteriorate in our plants.

On large main substation transformers, a more sophisticated temperature relay is used that more closely reproduces the hot-spot temperature, and switches fans and sometimes an oil circulating pump on and off.

5.11 UNDERVOLTAGE RELAYS (27)

These are either induction disc, attracted armature, or solid state devices that operate when the voltage falls below a preset level. They may be instantaneous, definite time, or time delayed with an inverse characteristic that provides the fastest clearing at zero voltage. The symbol "27" is generally used for time delay relays and "27I" for instantaneous relays.

We use undervoltage relays for:

- Automatic transfer circuit in **GP 16-12-02**.
- Undervoltage protection (tripping) for motors controlled by circuit breakers, latched contactors, and d-c held contactors.
- Monitoring the voltages of the d-c control power supply for the switchgear plus the control voltage in each switchgear assembly, as per **GP 16-02-01** and **GP 16-12-01**.
- Step reacceleration circuits.
- Separation of in-plant generators from the utility (sometimes in combination with a second relay, such as a directional overcurrent).
- To off-load constant torque equipment such as positive-displacement/reciprocating compressors.
- To monitor voltage on each remote bus supplying Emergency Block Valves (EBV's) Type C and D (**GP 16-02-01**).
- To protect against a sustained undervoltage on the utility system that cannot be made up by transformer LTC action. This not commonly done but may be required at some locations. It is preferable to trip the incoming breaker before motors begin to trip and lock out due to overloading/overheating.
- To prevent damage from utility three-phase automatic reclosing where the reclosing involves a time delay that could damage rotating equipment (i.e., too long for ride-through and too short for individual motor undervoltage tripping).

5.12 DIRECTIONAL POWER RELAY (32)

See DIRECTIONAL OVERCURRENT AND POWER RELAYS (67 AND 32) below.

5.13 LOSS OF FIELD RELAYS (40)

Synchronous generators and synchronous motors are fitted with this relay, which typically uses one or two distance relays, and may include directional and undervoltage units. Loss of field can cause high currents in both the stator and rotor which can lead to dangerous overheating in a very short time. The var drain on the rest of the system can result in low system voltage and can adversely affect system stability. See [DP XXX-B](#).

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For salient-pole generators that may operate at low output levels; e.g., backpressure steam regulation, a separate field failure relay should be provided in addition to the normal 40 relay. This is because, at low driving torque levels, the machine may lose synchronism but not activate the conventional loss-of-field relay, yet still be damaged by overheating. The field failure relay monitors the applied field voltage, in addition to other parameters.

5.14 NEGATIVE-SEQUENCE OVERCURRENT RELAYS (46) - GENERATOR PROTECTION

Device number 46 is used both for Phase Balance relays, which respond to unbalanced phase currents, and for Negative Sequence current relays, which respond to the negative sequence component of unbalanced phase currents. The negative sequence type is more sophisticated and thus provides better protection with less false tripping than the unbalance type. It is our normal practice to provide Negative Sequence Current (46) relaying to generators, and to trip the generator breaker with this relay. The application of Phase Balance relaying is covered under the next subheading below.

Negative sequence currents are caused by system imbalances and asymmetries such as unbalanced faults, untransposed transmission lines, an open-circuited phase, and unbalanced load. Negative sequence currents in a machine stator induce double-frequency rotor currents, which produce additional heating that can be damaging even when the total phase current is less than rated current. Even a small voltage unbalance can produce significant negative-sequence current because the negative-sequence impedance is relatively low - approximately equal to the subtransient reactance for a generator (or the locked rotor impedance for a motor). Thus a 5% negative sequence voltage applied to a generator with $X_2 = 12.5\%$ can produce $I_2 = 40\%$ of generator rated current, which would quickly cause an excessive temperature rise.

Generators have a short-time negative-sequence-current limit expressed as $I_2^2 t = K$, where K is, for example, 30 for an air-cooled cylindrical rotor machine (per MG-1). Generators have a continuous I_2 capability limit which is typically 10 percent of the rated phase current (per MG-1), and may be as high as 15% in some machines.

Electromechanical negative-sequence current relays have an extremely inverse I_2 versus time characteristic which generally cannot be set more sensitively than to pickup at about $I_2 = 60\%$ of rated full load current; therefore their primary tripping function is to protect the generator against an uncleared phase-to-phase fault.

It is herein recommended that solid state negative-sequence current relays be used for generator protection because they provide more sensitive protection than electromechanical relays. Solid state 46 relays typically can protect generators against I_2 currents almost as low as the generator's continuous I_2 capability. For example, if a relay has a maximum delay of 990 seconds, and K is 30, the relay will correctly trip for I_2 down to 17.5% of generator rated current.

It is herein recommended that consideration be given to a 46 relay with the additional feature of a sensitive alarm setting (with a small alarm delay of about 5 seconds) which can warn the operator that a low level unbalance problem is developing. This may give the operator sufficient time to take prescribed actions, which could include separating from the utility if the utility is identified as the source of the imbalance; or determining the amount of imbalance and, if practical, reducing generator output to reduce machine temperature. Any of these actions would have to be pre-planned and documented as operating procedures.

Each application of a 46 relay has to be evaluated on its own merits. In some cases it may be preferable to immediately trip the generator breaker at the first sign of trouble because the utility can handle the load. In another situation, the in-plant generation may provide most of the power and it may be preferable to drop a weak utility tie - especially since it may well be the utility that is causing the imbalance.

5.15 PHASE BALANCE RELAYS (46) - MOTOR PROTECTION

Phase balance relays have typically only been applied to motors when this protection function is included as part of a comprehensive solid-state motor-protection relay. It is not required by ExxonMobil's Global Practices. However, where large unsparred critical motors are involved, it is recommended to consider phase balance relaying, which can be provided by a comprehensive solid-state motor-protection relay.

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5.16 NEGATIVE SEQUENCE VOLTAGE RELAYS (47) - MOTOR PROTECTION

This relay is not required by ExxonMobil's Global Practices, and has not previously been covered in this Design Practice. However, it is recommended that negative-sequence-voltage relaying, set to alarm, be considered for the main power buses of all plants. If there is in-plant generation which has tripped due to negative sequence relaying, that relaying is no longer there to indicate whether the negative-sequence condition is persisting and potentially damaging the plant's motors. Per **ANSI C37.96**, a motor with a typical 0.167 per unit locked rotor impedance, when subjected to a 5% negative sequence voltage, will experience a 30% negative sequence current and a 40 to 50% increase in temperature rise. Since this temperature rise is originating in the rotor, it will not be sensed by overload relays and probably would not be sensed by stator RTD's until it is too late.

A 47 relay is sensitive to imbalances in the source system upstream of the relay, but is much less sensitive to downstream imbalances because downstream imbalances generally have a minor effect on the upstream voltage that the 47 relay is sensing. A 47 relay applied on a plant's main power busses is likely to detect an open phase or other imbalances in the utility system, but not an open phase in an in-plant distribution feeder. Since our in-plant designs make it unlikely that we will have an open phase or other persistent imbalance inside the plant, we could apply 47 relaying on our main power buses to detect and alarm for the presence of negative sequence voltage arising from the utility company's system.

5.17 THERMAL OVERLOAD RELAYS (49) AND LOCKED ROTOR PROTECTION

In IEEE standards, device "49" is listed as a "Thermal Relay" which functions when a winding temperature exceeds a preset value. In practice, most motor overload devices in our plants do not sense winding temperature, but instead, they use stator current to simulate thermal conditions in the motor. In some cases, current-sensing overload relays are supplemented by winding temperature detectors which provide a high-temperature alarm. As used herein, the term "thermal relays" is applied both to separate relays supplied from external current transformers and to the thermal elements (sometimes called "heaters") in motor starters. As discussed below, a 49 relay may also be used to provide motor locked-rotor protection.

With few exceptions (discussed below), our motors are **tripped** for specified overload conditions via solid-state or thermal-element relays that monitor all **three** of the stator phase currents. Our practices do not call for tripping of motors via winding temperature detectors, which activate alarms upon sensing high stator temperature.

Thermal overload relays are normally set to pick up at 110 to 115% of motor full load amperes (FLA) for 1.0 service factor motors, and at 125% of FLA for 1.15 service factor motors. These settings provide protection against moderate overloads. Higher settings - up to 140% of FLA per discussion below - might be approved on an exception basis when normal settings trip the motor on starting, or when critical process considerations make it worth subjecting a motor to moderate overload rather than tripping it.

The role of thermal overload relays in locked rotor protection will now be addressed. Thermal overload relays protecting medium-voltage motors have to be supplemented by a separate overcurrent (51) locked-rotor relay in one phase. See [Figures 28 F](#) and [G](#).

Two things to keep in mind in the application of locked-rotor-current sensing devices are as follows:

- They may operate even though the applicable relay curve is above the trace of the starting current. This can happen because the relay integrates the effect of the current. Thus the relay curve either has to be set above the motor's total starting time (assuming constant locked rotor current), or the integration effect of the relay has to be taken into account (which is somewhat complicated, and will not be addressed herein).
- In some cases, it may not be possible for a locked rotor relay to both start/reaccelerate a motor and provide locked rotor protection because the motor starting time exceeds or is too close to the locked rotor damage time. In such cases one of the two options discussed at the end what follows has to be implemented.

Locked rotor protection for contactor-controlled, low-voltage motors is provided solely by the contactor's standard overload relays when the relay characteristic provides both locked-rotor protection and starting/reaccelerating capability. However, if they cannot be set to both prevent locked rotor damage and allow the motor to start (or reaccelerate), the following solutions should be evaluated:

- If the motor can be started/reaccelerated, but the overload relay does not provide locked rotor protection, add a separate locked rotor relay if it can be set above the motor starting time and below the locked rotor damage point.

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- If the motor cannot be started/reaccelerated because the starting time is too long for the standard (Class 10) thermal characteristic (cold curve for starting, hot for reaccelerating), investigate substituting an overload relay with normal pickup setting and a longer time delay at lock rotor current (e.g., a Class 20 or 30 overload relay). If the longer delay allows starting/reacceleration but it does not provide locked rotor protection, add a separate locked rotor relay that permits starting and provides locked rotor protection.
- If the motor still cannot be started using longer delay characteristics per above, change to the next size thermal element or increase the relay pickup so that the motor can start (or reaccelerate). This solution does not provide protection against moderate overloads. In no case shall the pickup exceed 140% of motor FLA. If pickup would have to exceed 140% of motor FLA to permit starting/reacceleration, the overload must be replaced with one that picks up below 140%. With pickup not exceeding 140% of motor FLA, and with the motor able to start/reaccelerate, the overload relay must either protect against locked-rotor damage, or it must be supplemented by a separate locked rotor relay.

If a motor's starting time exceeds or is too close to the locked rotor damage time, simple locked rotor protection will not work properly. In this case, thermal overload relays provide protection against moderate overloads, and a separate locked-rotor relay must be provided with supervision per one of the following:

- Use a "zero-speed" switch to supervise a locked rotor relay set to protect the motor against locked rotor damage. The switch disables the relay trip signal if the motor achieves a preset low-level speed soon after the motor is energized.
- Use a distance (mho) relay to supervise a locked rotor relay set to protect against locked rotor damage. The distance relay (21) operates immediately when it sees a locked rotor impedance, and closes its contact which is in series with the contact of the locked rotor relay. If the 21 relay continues to sense a locked rotor condition, the locked rotor relay will trip the motor when it finishes timing out. However, if the motor impedance changes sufficiently to indicate that a successful start is underway, the 21 relay drops out and disables the trip signal from the locked rotor relay. Check with the relay vendor to determine if it is preferable to use a three phase distance relay over a single phase relay for this application.

If it is specified that a piece of driven equipment is so critical to the process that it is preferable to sustain moderate insulation aging/damage than to trip for a moderate overload, the overload relays shall be set higher, and shall be supplemented by winding temperature detectors (or less preferably by an additional thermal-overload relay) set to alarm at or just above motor rating. The alarm has to sound in a manned control room so that immediate attention can be paid to the situation. The normal overload relays would be set to trip above any foreseeable overload (such as a surge condition in a compressor) but not above 140% of motor FLA. If the critical motor is a low voltage motor and is not protected against locked rotor by the "tripping" overload relays, a separate locked rotor relay must be provided.

The locked-rotor function of a multi-purpose motor-protection relay can be used in place of a separate locked rotor relay if its range and adjustability provide proper protection. The locked rotor protection functions of some multi-purpose relays have limited adjustability and are tied to both the hot and cold thermal curves, thus potentially creating difficulty in fitting the relay characteristic between the motor start time and the locked rotor damage point(s). If the locked rotor function does not have its own output contact, it could not be used with the speed switch or distance relaying schemes above.

The additions and exceptions to tripping of motors via current-sensing thermal-overload relays in all three phases are as follows:

- Thermal overload relays are disconnected for Type C and D Emergency Block Valves (per **GP 16-02-01**), and thermal overload relays are not provided in the starters for firewater pumps. The basis for omitting overload protection is that the risk to people would be greater if the motor is tripped on overload than if it is not.
- When low voltage motors are controlled by switchgear circuit breakers with direct acting trips, the direct acting trips provide overload and locked rotor protection, with backup via an overload relay in one phase.
- Motors with air filters and motors over 1500 HP are to be provided with the additional protection of a high temperature alarm from resistance temperature detectors imbedded in the stator winding. The alarm level should be at or just above the rated temperature of the winding. Overload and locked rotor protection are provided by relays per normal practice discussed above.

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5.18 INSTANTANEOUS OVERCURRENT RELAYS (50)

Instantaneous overcurrent relays (50) are electromechanical or solid-state relays with very short operating times - on the order of one-half to one cycle at or above 5 times pickup, and about 1.5 cycles at 1.5 to 2 times pickup. Below 1.5 to 2 times pickup, relay operating time may be 2 to 5 cycles or more. Thus instantaneous relays are not truly instantaneous. See [Figure 7](#).

Some instantaneous relays have low overreach (see [DEFINITIONS](#) section) because of dc filters, and therefore they see much less current than may actually be flowing in an offset fault current. See [Figures 3, 4, and 5](#). Low overreach allows these relays to be set lower than high overreach relays, thus providing more sensitive protection. See [Figure 6](#) for typical overreach data on a low overreach 50 relay.

In summary, instantaneous overcurrent relays:

- Are calibrated in symmetrical rms amperes.
- Pick up at a current equal to the setting value.
- Have very rough rule of thumb operating times of one and a half cycles at a current equal to 1.5 times the setting, and half to one cycle at a current equal to five times setting.
- Some are available with d-c filters to reduce transient overreach to much lower values than unfiltered relays.
- Vary in performance. Manufacturer's data of actual relay should be used.

5.19 INVERSE TIME OVERCURRENT RELAYS (51)

These relays either have an induction disk that rotates when the current is above the setting to close a set of contacts, or are electronic solid state devices. The role of 51 relays in motor locked-rotor protection is discussed above under THERMAL OVERLOAD RELAYS (49) AND LOCKED ROTOR PROTECTION.

Facilities are provided to adjust both the current setting and the time of operation to give a family of curves for time vs. current. In the case of electromechanical relays, the current is adjusted in steps by inserting a plug into a socket that usually has a current range of four to one times nominal current in seven steps. The time is adjusted by a dial that varies the angular distance through which the disk has to rotate to close the contacts. This "time dial" is infinitely variable over a range of settings. Typical setting ranges are 0.5 to 10, 0.1 to 1. A typical family of curves for an inverse time induction-disk overcurrent relay is shown in [Figure 8](#). A typical solid-state relay has a current range of 2.4 to 0.05 times nominal current in 47 steps. Its time characteristic can be varied from 0.05 to 1.0 times the time of the base characteristic (in steps of 0.025). For the inverse time characteristic, this results in a range from 0.1 second to 2.0 seconds at 31 times the current setting, in steps of 0.05 second. This is comparable to the time range of the induction-disk relay in [Figure 8](#).

It will be noted in [Figure 8](#) that the curves are not extended below a current of one and a half times the tap (current) setting. In theory, the relay should pick up at the current setting of the tap selected but, in fact, the induction disc generally starts to rotate (pick up) at a current slightly above the tap setting. Thus, the relay's accuracy in the region of the pickup current is not reliable. One solid-state-relay manufacturer shows the relay curves dashed below 2 times pickup and gives accuracy data only above 2 times pickup.

At high multiples of the pickup setting, varying from 20 to 50 times pickup, depending on the relay, the Time vs. Current curves of inverse relays tend to go asymptotic. Because of this, many inverse time relays are designated as Inverse Definite Minimum Time (IDMT), with a specified minimum time of operation at the point where the Time vs. Current curve becomes asymptotic at high currents. This time is useful when determining time dial settings to provide discrimination between relays.

Relays are available with varying degrees of Time vs. Current slope to suit the various applications. The normal classifications are "Extremely Inverse," "Very Inverse," and "Inverse," as shown in [Figure 9](#).

Extremely inverse relays are useful in providing discrimination with fuses, as the shapes of the two Time vs. Current curves are similar. Where coordination with fuses is not a problem, an inverse-time characteristic provides a relatively short operating time over a wide range of currents, and is the curve of choice in the majority of applications.

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Extremely inverse relays should not be used for transformer primary protection as they are not suited to the large range of currents over which selectivity is required. Transformer primary protection (51) relays have to see through the transformer for secondary faults. If extremely inverse relays are used for primary protection of transformers, it is generally not possible to meet the **GP 16-02-01** requirement of operating in less than two seconds at 50% of minimum secondary bolted phase-to-phase fault current.

One feature of all inverse time overcurrent relays, both induction disk and solid state, is overtravel/overshoot (see [DEFINITIONS](#) section) which causes the relay to continue to "time out" for a short time after the current has ceased. For selectivity, it is common to allow 0.05 (solid state) to 0.1 second (induction disk) for overshoot of upstream relays. Use actual relay overshoot data where available.

5.20 DEFINITE TIME OVERCURRENT RELAYS (51)

These relays are an alternative to the inverse time overcurrent relays and are designated by the same number 51. They may be considered as an instantaneous relay (50) plus a timer, thus, it can be seen that their operation occurs after the setting current has been maintained for the duration of the time setting. The Time vs. Current operating curve is shown in [Figure 10](#).

Some advantages of Definite Time Overcurrent Relays over Inverse Time Overcurrent relays are:

- They provide as good (fast) protection at low fault levels as at high levels.
- They are very easy to apply for discriminating between each other.
- 1. Disadvantages are:
 - The shape of their Time vs. Current curve is undesirable for discrimination with fuses.
 - The shape of their Time vs. Current curve does not follow the thermal overload characteristics of generators, motors, transformers, etc.

Ideal applications for Definite Time Overcurrent relays are for system fault protection where it is not necessary to coordinate with fuses and the thermal characteristics of equipment.

5.21 VOLTAGE-RESTRAINED (VOLTAGE-CONTROLLED) OVERCURRENT RELAYS (51V)

We use these relays for generator and generator-busbar overcurrent back-up protection (see [DP XXX-B](#)).

A voltage-restrained relay uses voltage to apply restraint to an overcurrent relay. For example, a 51V relay that picks up at 200 % current when the voltage is 100%, may pick up at 50% current when the voltage is zero. The pickup, and therefore the relay curve, varies continuously with voltage, which makes coordination analysis more complicated than with the voltage-controlled type of relay.

A voltage-controlled relay works as follows: when voltage is above the relay's voltage setting, operation of the overcurrent element is blocked or a relatively high pickup characteristic is selected; but when the voltage dips below the relay's setting, a low pickup characteristic is enabled. The voltage setting should be below the lowest expected voltage during motor reacceleration or other stable voltage transient (probably set just below about 60% voltage).

We need the increased sensitivity of the 51V for generators under fault conditions because, being backup protection, the relay has a relatively long time delay, and during this delay, the generator fault current will decay significantly from its initial value. Without voltage restraint, an overcurrent characteristic set high enough to avoid tripping for non-fault conditions would take unacceptably long to operate for a decaying fault current, if it operated at all.

We put the current transformers (CTs) for the 51V at the neutral end of the generator phase conductors. This location provides backup protection for the generator when the generator is connected to a system that has little or no capability to backfeed fault current into the generator (e.g., island operation). If the potential transformers (PTs) for the relay were on the generator side of the generator circuit breaker, the CTs in the generator neutral leads would provide backup to the generator differential protection when the generator is energized prior to connection to the system. However, we usually use the main bus PTs for the 51V to save the cost of the extra set of PTs that would be required to obtain this infrequently needed protection.

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The 51V provides the ultimate backup for an uncleared fault in all parts of the electrical system into which its setting can reach.

The 51V has an inverse characteristic, which coordinates well with the inverse characteristics of our in-plant relaying. However, if a generator is stepped up directly to a transmission system protected by distance relays, one would use distance relaying in place of 51V relaying. In this case, attention must be paid to the configuration of the CTs and PTs relative to the winding configuration of the step-up power transformer.

Because the generator fault current is decaying with time and the relay is integrating the effect of the current, a relay with an inverse time-current characteristic will operate some time sooner than the time where the trace of the decaying current intersects the relay curve. Thus it is not apparent when relays will operate, and what the discrimination interval between relays will be. The analysis is made more complex if the relay characteristic varies with voltage as it does with the voltage-restrained type of 51V relay. **GP 16-02-01** requires a relay coordination study to take account of generator decrement effects on relay operation per the method reported by Arnold Kelly in IEEE Transactions on Industry and General Applications, March/April, 1965, pp. 130-139.

Generator decrement varies with loading, exciter response, and electrical distance from the fault. The 51V relay should be set with the minimum safe discrimination interval practical for the maximum fault current through the 51V at zero voltage, and for the least current that would flow simultaneously through the downstream relay. This condition is usually obtained when the generator with the 51V is the only source of fault current. The setting should be checked for proper operation under emergency operation conditions such as motor reacceleration and stable transient swings for which tripping should not occur.

If the voltage signal drops to zero, typical 51V settings will result in operation of the relay for generator load currents above about 50% of generator rating. Thus a generator can be tripped off line due to nothing more than a blown PT fuse. To avoid this problem, voltage balance relaying (device 60) or other PT blown fuse protection should be considered (as discussed further below).

5.22 OVERVOLTAGE RELAYS (59)

Overvoltage protection monitoring bus voltage is not normally provided in our systems, but could find application when a generator vendor requires such protection, or where power factor correction capacitors could cause overvoltage at light load. For generators, volts/hertz relaying (device 24) would be the preferred overvoltage protection, if overvoltage protection is to be provided. If device 59 is provided for generator terminal voltage, it would typically be used to alarm, and would be supplied from the relaying PTs, and not from the PTs for the generator's voltage regulator. Device 59 is used to monitor voltage across the resistor of a high resistance grounded system, and alarms or trips depending on operating philosophy.

5.23 VOLTAGE BALANCE RELAY (60) / PT FUSE FAILURE

It is recommended that voltage balance relaying (60) or other PT blown fuse protection be considered to protect against false tripping of a generator due to a blown fuse in the PTs used for 51V relaying (or 40 or 21 relaying). It also protects against false tripping of motors due to misoperation of 27 or 40 relays. The IEEE and GE recommend such protection. It can be provided by a voltage balance relay of the type that connects between two sets of PTs which sense the same voltage, or by the PT fuse-failure feature of a digital generator-protection system. This protection should sound an alarm and block tripping by the relays affected by the loss or reduction in voltage. The voltage balance relay should be connected between the PTs for generator relaying and the PTs for the generator's voltage regulator.

5.24 BUCHHOLZ AND SUDDEN PRESSURE RELAYS (63)

If fault pressure protection is applied for oil-filled transformers, it will be rate-of-rise type for sealed tank designs, or Buchholz type where conservator tanks are used. The Buchholz relay is connected in the pipe between the conservator and tank of an oil-filled transformer. It traps bubbles of gas released in the transformer as they travel to the highest point and initiates an alarm to signify an incipient fault. It also trips the transformer circuit breaker(s) if there is an internal fault that causes a surge of oil. There have been reports of false operation of rate-of-rise type relays due to rapid changes in ambient air temperature and due to through faults, with the result that many such relays have been disconnected. Hopefully, the root causes of these false trips will be found, and the relay design will be changed as necessary since this relaying provides for rapid disconnection of transformers under 10 MVA where differential relay protection is not normally provided.

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5.25 DIRECTIONAL OVERCURRENT AND POWER RELAYS (67 AND 32)

Two types of Directional Relays discussed herein are the directional overcurrent relay (67) and the directional real-power relay (32), both of which sense the magnitude and direction of the measured quantity. In order to do this, the relay requires a polarizing signal (usually voltage) in addition to the current input. Directional relays will operate correctly with a voltage as low as 1% for faults near the relay.

When showing these relays on a one-line diagram, an arrow should always be added pointing in the direction that the current (or power) must flow for operation of the relay (i.e., the direction in which the relay is "looking").

Directional Overcurrent (67) relays are required wherever there is a closed loop, such as a spot network substation, to provide selective tripping either as the prime protection or back-up to unit protection.

Generally, directional overcurrent relays should not be used to protect a generator cable. It is very difficult to set this relay so that it will provide cable fault protection but not operate for stable system transients which cause reactive current flow into the generator (similar to loss-of-field conditions) but which would not cause field failure relay (40) operation. The generator cable should be protected by the generator differential relay. See [Figures 11](#) and [12](#).

Where circumstances such as distance between the generator and its circuit breaker necessitate use of the directional overcurrent relay as in [Figure 11](#), particular attention must be devoted to selection of the operating characteristics and settings of both the directional overcurrent and field failure relays to minimize the possibilities for the false operation described.

The directional or reverse power relay (32) protects against power flow from the system into the generator which occurs on loss of drive motive power. This relay is required for all gas turbine generators due to the substantial power drain from the system required to motor the gas turbine. It may not be required for steam turbine generators (power drain is relatively small) if the turbine has protection and alarm provisions for the motoring condition.

Very sensitive reverse power relaying is used at the secondary of an import-only utility-tie transformer to sense the loss of the primary-side voltage when there is a secondary-side voltage source. This is needed when the opening of a remote primary-side circuit breaker does not send a transfer trip signal to the transformer's local circuit breakers.

5.26 FREQUENCY RELAYS (81)

The main applications for these relays are:

- Load shedding
- To separate in-plant generation from the utility

A more sophisticated variation of this relay measures rate of change of frequency which is often a better yardstick when deciding how stable the system is at any one time (see Subsection B).

5.27 PILOT-WIRE RELAYS (85)

Pilot wire relays are most often used as distribution or transmission line differential relays. When medium and high voltage line differential zone of protection extends over long distances, say in excess of a few hundred feet, a differential pilot wire (85) scheme is generally used. The scheme employs a relay and three CTs at each end, and a pair of pilot wires between the relays to permit comparison, instead of extending all of the current transformer secondary circuits from one end of the zone to the other. See [Figures 17](#) and [18](#). The outputs of the three current transformers are summed unequally such that a balanced three-phase fault produces a net input to the relay.

In the case of conventional differential protection, four or six conductors are required to connect the CTs to the three 87 relays. Larger conductor sizes are required as the distance between the two ends of the zone increases.

Pilot wire protection only requires one pair of wires between the ends of the zone that can be miles apart. Supervision of the pilot wire circuit is available. Pilot supervision will detect and alarm a short circuit, open circuit, or earth fault on the pilot wires. It is usual for us to apply "pilot supervision" on these pilot wires.

The pilot circuit can be provided by fiber optic cables; this is the preferred method when longer distances are involved. Relays are available that are designed for fiber optic interconnection and adapters can be installed to replace existing copper-pair interconnections to eliminate problems with ground potential rise and induced current.

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5.28 LOCKOUT RELAYS (86)

Sometimes called "master tripping relay." It is an interposing relay in the trip circuit of a circuit breaker which can be initiated by one or several protection relays. When energized, it does three things:

1. Seals in.
2. Trips the protected circuit(s) by sending a trip signal to one or more circuit breaker(s).
3. Isolates the closing circuit of the circuit breaker(s) supplying the protected circuit to prevent either automatic or manual reclosure.

Note that the relay should isolate the circuit breaker's closing circuit which is different from maintaining a trip signal. In the former case, the breaker cannot be closed, in the latter, the breaker can be closed but will trip again immediately.

Reset of the relay may be electrical or by hand. We always use hand reset.

Lockout relays may be series or shunt type. The description of these is given in **GP 16-12-02**.

We use lockout relays with hand reset for:

- Medium voltage motors, unless the relays for fault protection have mechanical lockout incorporated in them (**GP 16-12-01**).
- Transformers where we specify transformer protection or transformer secondary protection (**GP 16-12-02**). When transformer differential protection is applied, the differential, Buchholz (or fault pressure relay) and transformer neutral grounding relay are all required to act through a lockout relay which in turn trips the transformer primary feeder circuit breaker and the main secondary breaker per **GP 16-02-01**.
- Generators - operated by all the generator protective relays. We generally use two lockout relays for this duty. One for the generator faults, e.g., differential, and the other for external faults, e.g., 51V.
- Busbar differential protection.

5.29 DIFFERENTIAL RELAYS (87)

These relays measure the difference between the current entering a part of the network and the current leaving the same part of the network. If there is a discrepancy between these two measurements, there must be a fault, so the relay operates. This is a type of "Unit Protection" or "Zone Protection" as the relay is only looking at one unit of the network (a cable, transformer, motor, generator, or busbar), and if "what comes out" does not equal "what goes in", there is a fault in that unit, so the relay operates "instantaneously" to trip the circuit breaker(s).

Examples of differential protection are shown in [Figures 13, 14, 15, and 16](#).

Differential protection is more expensive than conventional overcurrent protection but has several distinct advantages:

- Selectivity is not required with other relays. This permits sensitive settings with "instantaneous" operating times.
- Location of fault is known - it must be in the zone of protection.

We usually apply differential protection to:

- Main substation power transformers, generator unit-transformers, and all transformers rated 10 MVA and larger.
- Motors rated 2501 HP (1801 kW) and above.
- Generators (except Instrument Power Supply (IPS) generators as these are small).
- Busbars and cables connected to a system that has a generator operating at the same voltage.
- Main substation busbars.

The selection of high-speed differential protection helps to maintain system stability for plants with in-plant generation.

As differential protection is required to operate only for faults within the zone of protection, it must be stable (not operate) for faults that are outside the zone. These "through faults" will cause large currents to flow which will be equal in the input and

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output circuits of the differential relay's zone of protection. However, the input and output currents sensed by the differential relay will not be equal due to CT errors, therefore, the relays need to have a "percent bias" to avoid false operation. Such relays are called "percent differential relays". The percent bias is achieved by introducing restraint against relay operation in such a way that there is significant restraint against operation for external faults, and there is virtually no restraint for internal faults. This bias is normally expressed as the ratio of the "erroneous" operating current to the average restraining current. If the actual error current in the operating coil (expressed in percent of the actual restraining current) is less than the relay's percent bias, the relay will not operate for a through fault. The percent bias can be either fixed for all through currents, or variable, with the percent restraint increasing as the through-current (and therefore the current transformer error) increases. Thus if the maximum error expected between the current transformers is 10% for the maximum through fault, a fixed 15% or 20% bias characteristic will prevent false operation. If the error between current transformers could be relatively high at high through-fault currents, the better choice is a variable percent differential relay which varies the operating to restraining ratio from about 5% to 10% at low currents to as high as 60% at high currents.

Transformer differential protection is more complex than differential protection for motors, generators, lines and buses because:

- When the ratio of the current-transformer ratios does not equal the current-ratio of the power transformer, there is an error current to the differential relay operating coil; e.g., a 13.8/4.16 kV transformer has an ampere ratio of about 1:3.3, whereas the associated CTs may be 200/5 and 600/5 (a 1:3 ratio). Thus a through fault gives rise to a guaranteed 10% error current in the operating coil in this example.
- There is often a phase angle difference between the primary and secondary currents, unless the transformer vector connection is star / star or delta / delta.
- The ratio of primary to secondary current varies with the transformer tap changer position.
- There may be large inrush currents when the transformer is energized, giving the appearance of an internal fault.

To overcome the above problems, the transformer differential protection (usually denoted by 87T) is arranged as follows:

- If there is a ratio mismatch between the power transformer and current transformers, the differential relay should have adjustable taps to compensate for this ratio mismatch, or auxiliary current transformers with taps need to be interposed to correct the mismatch.
- To compensate for phase angle difference, the CTs on the transformer delta winding are connected in star, and the CTs on the transformer star winding are connected in delta.
- To compensate for the variation in the power transformer ratio due to tap changing, transformer differential relays have a larger minimum percentage bias (10 to 40%) to desensitize the relay as compared with a generator differential which has a percentage bias of 5 to 10%.
- "Harmonic restraint" is built into the relay to prevent false operation when the transformer is energized, or when inrush occurs due to transients such as fault clearing. **GP 16-02-01** requires harmonic restraint on all transformer differential relays.

5.30 GROUND (EARTH FAULT) RELAYS (50N, 50G, 50GS, 51N, 51G, 51GS, 67N)

See **DP XXX-D** for descriptions of ground fault relay types and applications. They can either be supplied from three CTs connected residually (for which we usually use the symbol "N"), or from a CT in the neutral of a generator or transformer, or from a core balanced CT on a feeder cable. In the two latter cases, we usually use the symbol "G" although, this convention is not universally followed by all vendors in their application literature.

Ground fault protection is sometimes provided by phase fault protective devices, such as in the case of out-going feeders on solidly-grounded, low-voltage systems when local regulations permit it and when clearing of arcing ground faults is achieved in under two seconds. Generator phase differential relaying may be sensitive enough to provide first line ground-fault protection for generators.

- ✦ Incorrectly connected, or improperly set, earth fault relays will not be revealed by balanced load currents. Therefore, it is important to confirm their proper operation at commissioning, using primary injection.

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6 CURRENT TRANSFORMERS

Current transformers form a vital part in protective relaying as we depend on them to reduce the large primary currents to manageable levels for the relays. When selecting current transformers for Design Specifications, generally the only parameter specified is the ratio, but the following factors should also be taken into consideration:

- Number of CTs on a circuit. We do not normally use the same set of CTs for differential relaying, overcurrent relaying, overload relaying, and metering, although technically it is possible. All differential circuits should have their own CTs. Metering and overcurrent relaying are preferred to be on separate CTs. The revenue (custody) metering will always have its own CTs.
- Burden on the CTs. Even after it has been determined that several sets of CTs are required, there may be too high a burden on one set, although this is very rare and may only present a problem with generator relaying.
- Auxiliary CT's should be avoided if possible, however, if used, their burden must be added to the total. The burden of relays 'downstream' of the auxiliary CT is multiplied by the square of the auxiliary CT turns ratio.
- Overlapping zones. Differential circuits and directional relays should be arranged where possible with overlapping zones.
- Space. Having given all the reasons above for adding current transformers, it must be borne in mind that the space for CTs in equipment generally limits us to two or three sets at the most. More space is unusual.

When purchasing CTs, other factors have to be taken into account, such as:

- Knee voltage - which must be high enough to drive the relays. Care must be taken with multi-ratio CTs because the accuracy of the CT at the knee point on the lower ratios may not be adequate.
- Accuracy required for the specific application. Accuracy is measured in terms of ratio error, which is effectively the error between what the secondary current would be based on the turns ratio and what it actually is. This error is expressed as a percent of what the ideal secondary current would be without the error. For CTs for which the accuracy can be calculated (as discussed below), it is reasonable to use the calculated excitation current (divided by the ideal secondary current) as the measure of the error for phase devices. The excitation current is a function of the voltage across the CTs burden, which voltage is calculated when the current through the burden is the largest current for which operation is desired. This is usually the maximum three-phase short circuit current reflected through the CT turns ratio. Some text books indicate that when an instantaneous relay (50), set to trip, comprises part of the burden, the setting/pickup of the 50 relay can be used instead of the maximum short circuit current. We recommend against this approach because at 50 pickup (and up to at least 1.5 to twice pickup), the operating time of the 50 can be several cycles, which gives the CT time to saturate for currents higher than the 50 pickup. Thus we recommend calculating CT error for phase devices at the maximum short circuit current.

Current transformers are available in two broad grades; namely, Metering and Protection. Metering CTs are designed for accuracy which is typically 0.1% error at rated current, whereas protection CTs are typically designed for an accuracy where the error is no higher than 10% at 20 times rated CT secondary current flowing through a standard burden.

Please note that the CT accuracy rating, discussed below, applies to the highest turns ratio of a multi-ratio CT, and for currents and burdens no higher than those upon which the accuracy rating is based. Separate accuracy ratings or other accuracy information for the other taps would have to be provided by the manufacturer.

In the USA, a protective-relaying CT has no more than 10% ratio error when the voltage across its burden is equal to or less than the secondary terminal rated voltage specified in its accuracy rating. This rated voltage is applicable when it is developed across a standard burden at 20 times the CTs rated secondary current. The 10% error limit applies for all currents less than 20 times rated secondary current at the standard burden, or any lower standard burden used for CT accuracy rating. The voltage in the accuracy rating is normally very close to the CT knee voltage.

The accuracy rating in the USA is comprised of a letter and the secondary terminal voltage rating discussed above; e.g., C200 or T200. The letters C or T associated with the rated voltage have the following meaning:

- The C designation means that typical excitation curve data can be used in a simple calculation of the effective (corrected) CT ratio. The simple calculation of corrected CT ratio assumes that the effects of flux leakage are negligible. With this assumption, the voltage across the burden of a CT can be used directly to determine the CTs exciting current from typical excitation curves. The "C" designation cannot be used if the corrected CT ratio determined by this simplified calculation would not be within 1% of the CT ratio determined by test for the same conditions.

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- The T designation means that CT-ratio test data must be used to determine the effective CT ratio for various currents and burdens, because the simplified calculation method would not be accurate enough, as described above. The results of ratio tests for a given CT design are presented as a plot of secondary current versus primary current for various standard burdens, up to the highest standard burden which keeps the error below 50%. The currents are plotted in multiples of rated current up to 22 times the primary-side rated current.

Thus a C200 or T200 accuracy rating means the CT can develop 200 volts across the burden without exceeding 10% ratio error for all currents up to 20 times rated current and all standard relaying burdens up to the standard burden of 2 ohms (at 0.5 power factor). Twenty times current is 100 A (20 X 5 A), and the standard burden is 2 ohms in this case because $200V/100A = 2$ ohms. The standard burden is the voltage rating divided by 100 for all CTs with a 5 ampere secondary. If it becomes necessary to determine the CT accuracy for a specific set of conditions, the accuracy can be calculated for the C-rated transformer using typical excitation data, or it can be determined from ratio test curves for T-rated transformers.

As a first pass check of the accuracy of a CT for a specific application involving only phase devices, the CT is okay if the burden is equal to or less than the standard burden for its voltage rating, and if the available fault current is less than or equal to 20 times the primary winding rating. If these criteria are not met, either the accuracy has to be checked for the specific application or a higher-voltage-rating CT should be selected.

- The accuracy rating of a CT is not meaningful in the determination of error for a residually connected ground relay, 51N. Determination of the ratio error for a 51N application is complicated by the fact that the CT in the faulted phase has to supply excitation current to itself **and** to the other CTs, which are excited by the voltage across the 51N. When high-burden electromagnetic ground-fault relays are involved, the total error approaches three times the excitation current of the "faulted" CT. With low-burden solid state ground-fault relays, the total error will be much less than with electromagnetic relays, and the excitation current added by the other CTs is likely to be considerably less than the excitation current of the "faulted" CT.

For differential and N-type relays, another check must be made if the power system has a high X/R ratio. A momentary DC component in the power system current flow can easily saturate CT's (or any interposing ratio matching transformers) and cause false tripping of differential or residually connected relays. A high X/R ratio will occur where current limiting reactors are employed to reduce fault duty, for example, but can be found any place that a number of components are bussed together without significant cable lengths between them. To ensure **no** saturation takes place, the knee point voltage of the CT must satisfy:

- $$V_k > 2\pi TIR_{sec}$$

or

$$V_k > (X_{pri}/R_{pri})IR_{sec}$$

• Where:

- I - symmetrical secondary current in amperes (usually fault current)
- R_{sec} - total secondary resistance
- T - primary circuit time constant in *cycles*
- (X_{pri}/R_{pri}) - X/R ratio of the primary circuit involved in the fault calculation

It is not necessary to know the actual values of X and R just the ratio.

This ratio can be found in handbooks and is usually only a function of the size of the transformer, generator, etc.

Under some circumstances, the current with the longest time constant may not be short circuit current. The highest product of time constant and current magnitude determines the required V_k . Additional information is contained in ANSI C37.110.

- In Europe, a protection CT may be designated "100 VA 5 P 20" where the 100 VA is the burden, and accuracy is 5% or less error at a primary current of 20 times the CT's rated primary current. The "P" stands for protection; i.e., a CT used for protective relaying. The IEC Standard 185 covering CT's does not indicate how to deal with currents or burdens higher than those in the rating designation. "Overdimensioning" of CT's for transient performance is discussed in IEC 60044-6.

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Whenever a CT circuit is required at some remote location, such as in a control room for an ammeter, and the remote circuit does not form an essential part of the protection circuit, an interposing CT located in the substation should be connected in the protection circuit to isolate the remote circuit from the protection circuit. An isolating CT with a ratio of say 5/1 or 5/0.5 will have the added advantage of providing a higher driving voltage to the remote circuit and permit the use of a smaller cross-section cable.

6.1 CORE BALANCED (ZERO SEQUENCE) CURRENT TRANSFORMERS

See [DP XXX-D](#).

A core balanced current transformer consists of an iron toroid with a winding around the iron core. When cable is passed through the toroid without a ground return path, and the sum of the currents in the cable is ZERO, there will be no flux in the iron core (core balanced), whatever the magnitude of the three primary currents. However, any zero sequence (ground fault current) in the three-phased primary cable currents will create a flux in the iron core and a current in the secondary winding on the iron core proportional to the ground fault current in the primary circuit.

- Note that the conductors must be properly centered in the core "window", otherwise local saturation of a portion of the core may occur, causing an unwanted output from the transformer during high phase current flows. Presence of other magnetic materials in the immediate vicinity of the core window may have a similar effect. We use core balanced current transformers extensively on feeders and motor protection circuits to supply ground relays. Where possible, the zero sequence CT and the ground fault relay should be purchased as a unit. The ground fault relay is normally instantaneous and set to be very sensitive since it is not subject to the transient-offset CT imbalances of residually connected relays.

7 POTENTIAL TRANSFORMERS

These are generally two-winding transformers that are used to reduce system voltages to 110 V or 100 V for relays and metering. Due to the high cost of potential transformers above 15 kV, it is common to use capacitive coupling circuits, where the accuracy need not be as high as for metering.

- Failure of unfused potential transformers has resulted in several plant upsets over the years. GP 16-12-01 & 02 show primary and secondary fuses on medium and low voltage PT's.

8 BASIC DESIGN CONSIDERATIONS

8.1 PROTECTION PHILOSOPHY

A good protective relaying system should have the following attributes:

- It should operate in the shortest time possible consistent with reliable and selective operation, and with the economics of design. Economics often dictate that it is not justified to use the fastest and most sensitive protection in the form of high-speed differential relaying.
- It should shut down/isolate the minimum amount of the electrical system necessary to remove the faulty part of the network; i.e., it should be selective. Every level or zone of the electrical system should have fast first-line, or primary relaying. In addition, backup relaying should be provided where practical. Backup relays for one part of a system are often the first-line protection for another part of the system. For example (assuming no bus-differential relaying), a fault on an outgoing feeder should be cleared by the feeder protection, and not by the main-bus's primary protection. However, if the feeder protection fails to clear the fault, the main bus's primary protection should operate as the backup to the feeder protection. Backup protection for part of a system is not always the primary protection for another part; e.g., stuck-breaker protection; and 51 or 51V backup of a differentially protected bus or generator.
- It should be highly reliable in terms of repetitively operating per the setting, and in terms of operating when it is supposed to and not operating when it shouldn't. This not only encompasses the selectivity discussed above, but includes, for example: motor locked-rotor protection operating for a locked rotor condition, but not for reacceleration current; transformer primary-feeder 50-relaying tripping for a primary-feeder fault, but not for transformer inrush current, and not for a transformer secondary fault; a differential relay tripping for faults in its zone, but not for faults outside its zone.

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- It should be well documented. One-lines, three-line diagrams, settings sheets and the actual field settings should all be consistent. Logic diagrams should be provided for microprocessor or "numerical" relays. Relay application brochures for all relays used should be available for maintenance personnel.

With the above attributes, a well-designed protection system minimizes damage and downtime of faulty parts of the system, and minimizes the impact of electrical faults on the healthy part of the system, thereby enabling plant operations to progress with minimum interruption.

8.2 OVERCURRENT DEVICE COORDINATION (SELECTIVITY / DISCRIMINATION)

To ensure that all of the protection-system attributes discussed above are met, a protective device coordination study is required. The most common form of study covers the selection, setting and coordination of overcurrent devices; although voltage, power, and impedance relays may sometimes be involved. For overcurrent devices in series with a fault, coordination requires that the overcurrent protection closer to the fault (the downstream devices) interrupt the fault before backup protection (the upstream devices) can operate. Overall, the objective is to provide the fastest practical protection while ensuring that no healthy equipment is taken out of service unnecessarily.

For the hypothetical system shown in [Figure 20](#), Breakers 2 and 3 do not have to coordinate with each other, nor do Breakers 4 and 5, since no healthy part of the system would be affected unnecessarily by this lack of coordination. However, Breakers 1 must coordinate with Breakers 2 and 3, and Breakers 2 and 3 must coordinate with Breakers 4 and 5. If there were a transformer between Breakers 2 and 3 in [Figure 20](#), there could be reasons to coordinate Breakers 2 and 3; e.g., if Breaker 2 is the incomer of a secondary selective substation.

Overcurrent-device coordination analysis is performed on log-log paper (or computer screen equivalent), with the current on the X-axis and time on the Y-axis. See [Figure 32](#). Where there is a transformer between overcurrent devices, the time-current curves of both devices are referred to the same voltage level. To achieve coordination, a minimum amount of time is required between the upstream and downstream overcurrent-device curves at the maximum current that will exist simultaneously in both devices. The minimum amount of time required to achieve coordination is called the coordination interval or coordination margin. This form of coordination is sometimes referred to as time grading.

Another form of coordination is current grading, where an upstream device is set above the fault level at a downstream relay's location. This is illustrated in [Figure 21](#), where an instantaneous relay (A) on the primary of a transformer is set above the secondary-side fault level (at location B) times any overreach factor applicable to the instantaneous relay at A.

Coordination Factors - Various coordination factors that must be accounted for in the determination of the minimum required coordination interval are as follows:

- Accuracy of the time-current curves relative to error / tolerance associated with both the upstream and downstream curves; overtravel of upstream relays; and the effect of pre-loading on minimum-melt curves of upstream fuses. Relay error is typically a percent of the setting time, with a fixed minimum error time.
- "Downstream" current-transformer error. CT error typically contributes to the coordination margin by reducing the current seen by the relay, thus making the downstream relay slower than the curve indicates. The upstream relay would not have a compensating delay if the upstream CT is more accurate, which can happen when the upstream CT has a higher turns ratio. Unless a determination is made of the actual effect of CT error, a value of 10% of the downstream-relay time (at maximum current) is typically used to account for CT error.
- "Downstream" circuit breaker operating time, which does not have to be added if the operating time is already built into the device curve as is the case for direct-acting-trip devices.
- The relevant factors from above are summed and a safety factor is usually added to determine the coordination margin. The amount of safety factor is a matter of judgement. Assuming all of the other factors covered above are separately accounted for, the safety factor may be taken as 0.05 second for static relays and up to 0.1 second for electromechanical relays.

Where coordination is to be achieved across a delta-wye transformer, a current-shift is required for (wye) secondary-side phase-to-phase faults. For any given time, draw a dashed curve by shifting the transformer-secondary-51-relay curve right by multiplying the currents by 1.16. This accounts for the 1.0 per unit current in one primary phase when there is a 0.866 per unit phase-to-phase fault current in two secondary phases. Coordinate the primary-side relay with the shifted dashed curve.

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Known or assumed values can be used for any or all of the above factors to determine the coordination margin.

Coordination Margins - Margins for various coordination situations are discussed in the following:

- For relay to relay coordination, the coordination margin is the sum of upstream relay error and overtravel, downstream relay error and CT error, downstream breaker operating time, and a safety factor. The coordination margin is typically 0.3 to 0.35 for static relays, and 0.4 second for electromechanical relays. Static relays have very low overtravel. They are often more accurate than electromechanical relays, and tend to cause less CT error due to their lower burden.
- A low-voltage switchgear breaker with time-delayed direct-acting trip (and no instantaneous unit) can coordinate with downstream direct-acting trips and fuses if the upstream breaker's direct-acting-trip curve is above the maximum-clearing curve of the downstream device. Do not try to make molded case circuit breakers (MCCBs) coordinate with each other by disabling the upstream instantaneous unit, because the instantaneous unit is necessary to the safe operation of the MCCB.
- Some contactors exhibit an intentional (or unintentional) time delay on drop out. As a result, the upstream relaying must be set no faster than the motor protection plus drop out time of the contactor. Another way this can happen is if "fly-back" diodes are fitted to a vendor's standard (d-c) contactor coil.
- For an upstream time-delayed relay to coordinate with a downstream fuse or direct-acting trip, the coordination interval is equal to the relay error plus relay overtravel plus a safety factor. This interval is typically 0.15 to 0.25 second, and is added above the maximum clearing characteristic of the fuse or direct-acting trip.
- Fuse to fuse coordination is discussed in detail earlier in this Design Practice, under the side heading "FUSES". In summary, fuse to fuse coordination is most easily achieved using the manufacturer's selectivity ratio guides. Otherwise, use the maximum-clearing and minimum-melting I^2t data for current-limiting operation. For non-current-limiting operation, use the maximum clearing curve of the downstream fuse, and the minimum melting curve of the upstream fuse. The minimum-melting curves have to be adjusted for fuse pre-loading per the manufacturer's instructions. Coordination is achieved when the maximum clearing characteristic of the downstream fuse is below (or lower than) the minimum melting characteristic of the upstream fuse (adjusted as required).
- For an upstream instantaneous relay to coordinate with a downstream current-limiting fuse, the fuse's peak let-through current times 0.7 must be less than the rms pickup of the instantaneous relay. This is discussed in more detail in the earlier section entitled [PROTECTIVE DEVICE TYPES AND APPLICATION](#), under the side-heading FUSES, where peak let-through fuse data is discussed.
- Upstream fuses on the primary of a transformer must not be in their current limiting range for fully offset secondary faults. For coordination purposes, the upstream fuse minimum-melt characteristic must be shifted left for the pre-loading effect per manufacturers guidelines, and the downstream device curve must be shifted right by a factor of 1.16 times current values for phase-to-phase faults when the transformer is delta-wye, as discussed earlier in this section under the paragraph that begins with **Coordination Factors**.

8.3 BACK-UP PROTECTION

Whenever possible, we try to provide back-up protection. This is often inherent in our time and current graded protective schemes. For example, in [Figure 27](#), for a fault downstream of Relay 1, Relay 2 will "see" the same current as Relay 1 and operate a short time after Relay 1 if Relay 1 fails to open its associated circuit breaker. Thus, Relay 2 is providing back-up protection for Relay 1. Likewise, Relay 3 will provide back-up for Relay 2. It may also provide a second stage of back-up for Relay 1 if its current setting is low enough to "see" faults downstream of Relay 1. Relay 3 will also provide back-up for Relay 4, the generator differential protection. Per the configuration in [Figure 27](#), Relay 3 is the primary protection for the generator bus.

We do not require back-up protection for ground faults in transformer main secondary connections with impedance grounding (see [GP 16-02-01](#)), as this condition cannot be easily detected on the primary of a delta/star transformer. To provide back-up protection would require duplicating the relays on the transformer secondary, or restricted earth fault relaying.

8.4 GROUND (EARTH) FAULT RELAYING

See [DP XXX-D](#).

Ground relaying follows the same general rules as phase fault relaying but has the following additional points to consider:

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- System neutral grounding method affects how much ground fault current is available, with low resistance grounding resulting in the ground fault current being much lower than the phase-fault current.
- Transformers with certain winding and/or grounding configurations do not pass zero-sequence current from the secondary side to the primary side.
- Capacitive currents.
- High burden of some ground fault relays can affect current-transformation accuracy.

When sizing neutral resistors, **GP 16-02-01** requires that the ground current be not less than 15 times the lowest reliable operating current of the least sensitive outgoing feeder ground relaying, and not less than five times the lowest reliable operating current of bus ground relaying. It should be noted that for most induction disc type relays, the lowest reliable operating current may be as high as 1.5 times setting (pickup).

On solidly grounded low-voltage systems, where local codes permit, we do not provide ground-fault relays on feeder circuits when there is sufficient ground fault current to operate phase-fault devices. "Sufficient" current, per **GP 16-04-01**, means the phase protection of a given feeder must operate in less than two seconds for a phase to ground fault at the load end of the circuit with an arc voltage of 40 volts; otherwise a ground-fault relay must be added to the circuit.

A delta / wye transformer, for all practical purposes, offers an infinite impedance to zero sequence currents, therefore, the primary ground relaying of a delta/wye transformer is instantaneous since there is no coordination problem with secondary-side relaying. For other transformer winding and grounding configurations, the zero sequence impedance of the transformer should be ascertained.

When there is a solid phase to ground fault, the faulted phase potential falls to zero, and the capacitive (charging) current in that phase to ground will be zero. In a resistance grounded medium voltage system the two healthy phases will have capacitive (charging) current of 1.73 times normal; therefore every ground fault relay at that voltage level that is part of the same neutral grounding system will see a capacitive current equal to 3 times the capacitive (charging) current of one phase to ground of the cables downstream of the relay. (For a solidly grounded system, the relays would see 1 times the charging current of one phase.) The relays must be set above this capacitive charging current.

The output from core balanced (zero sequence) current transformers is low because:

- Often there is only half a turn on the primary.
- The fault current being measured is generally much less than phase fault current.
- The physical separation between the primary and the core is greater both because there are three conductors on the primary and because the CT is generally slipped over the main power cable with space between the cable and the CT.

For the above reasons, it is possible that the actual primary current required to cause pickup of a relay connected to a core balanced current transformer is two to ten times the relay setting. Therefore it is recommended that core balanced CTs and their associated relays be purchased as a unit. Where ground relaying is employed, it should wherever possible be of the core balanced type CT in preference to residually connected phase CTs.

8.5 MOTOR PROTECTION

Typical motor protection arrangements that comply with the Global Practices are shown in [Figure 28](#). It should be noted that one-line diagrams do not include the following which have been shown in [Figure 28](#) to give the complete protection details:

- Direct acting trip device numbers, number of elements, trip signals.
- Trip signal from fuse striker pins.

Motor overload and locked-rotor protection are covered in detail earlier in this practice under [PROTECTIVE DEVICE TYPES AND APPLICATION](#), side heading THERMAL OVERLOAD RELAYS (49) AND LOCKED ROTOR PROTECTION. Motor circuit ground fault relaying is covered earlier under the side heading GROUND (EARTH) FAULT RELAYING.

LV motors controlled by contactors are protected by three-element thermal relays for overloads, and by fuses or molded case circuit breakers for short circuits. Molded case circuit breakers have an instantaneous trip, and in some cases, have a thermal or solid state time-delayed trip intended for motor thermal protection. In these cases, we still use separate thermal overload relays to trip the contactor as they follow the motor thermal capability more closely. The molded case circuit breaker thermal elements are set above the contactor's thermal overload relays.

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Whenever a relay trips a contactor, the capability of the contactor should be checked to ensure that the relay does not require it to open for a current in excess of its rating. The fuse or circuit breaker should take over above the contactor capability limit.

Basically, we apply the same protection to LV motors controlled by switchgear circuit breakers as we do for contactors. The differences being that:

- We accept the breaker direct acting trips for overload protection, but back them up with a secondary thermal element in one phase.
 - We add an undervoltage relay if undervoltage protection is not otherwise provided.
 - We require a ground fault relay, for solid or low-resistance grounded systems, with the relay supplied from a core-balanced current transformer.
2. MV motor protection incorporates the following:
- Undervoltage protection if not otherwise provided. Critical motors should use two-out-of-three tripping for undervoltage, with appropriate PT fusing (3 individually-fused PT's, or two PT's with 4 fuses).
 - Hand-reset lockout for all fault protection relays.
 - Overload protection in three phases.
 - Locked rotor protection, in addition to overload relays, in at least one phase.
 - Ground fault relay supplied from a core balanced current transformer.
 - Differential protection on motors 2501 hp (1801 kW) and above, with a self-balancing scheme preferred per the lower sketch in [Figure 15](#).
3. Phase balance relays are not required by ExxonMobil Global Practices, however for large (>1MW) motors, they may be considered. Phase balance relays are available as phase-unbalance (simpler) and negative sequence (more sophisticated) types. The negative sequence type provides better protection with less false tripping than the unbalance type. With large motors, stator saturation during energization inrush can result in the relay seeing unbalanced current for up to a second. As a result, a time delay must be provided for these relays.

8.6 GENERATOR PROTECTION

This is covered in [DP XXX-B](#), but see also above Synchronizing Relays (25), Loss of Field Relays (40), Negative Sequence Relays (46), Voltage Restrained Relays (51V), Overvoltage Relays (59), Directional Relays (67 and 32), and Differential Relays (87).

Points to consider when applying generator protection are:

- Unless there is only one generator that always operates "in island", kW and kVAR can flow both to and from the generator.
- The protective relays must protect the generator and the integrity of the electrical system, but they must not inhibit the generator from providing its full capability to the electrical system.
- When operating in parallel with the power utility, detailed information will be required on the utility protective relaying in the area to determine the relay setting for separation from the utility.
- If the generator is operating in parallel with other generators or the utility, fast fault clearance times will be required to maintain transient stability, i.e., generator differential and bus differential protection.
- The Automatic Voltage Regulator (AVR) should be self-protecting, i.e., it should automatically change to manual, or a fixed setting, if faulty. It is not practical to protect for AVR faults with protective relaying.

8.7 TRANSFORMER PROTECTION

As nearly all the power transformers we use are step-down with a delta primary winding and wye secondary winding, the following comments are based on such a transformer. However, many of the comments will apply whatever the transformer vector reference (see [Figure 29](#)):