7SR224 Recloser Controller

Overcurrent Relay

Document Release History

This document is issue **2010/09**. The list of revisions up to and including this issue is:

2008/03	First issue
2008/06	Second issue
2008/11	Third issue. Single/Triple Autoreclose added
2009/09	Fourth issue. Maintenance release
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2010/09	Sixth Issue. TCS updated

Software Revision History

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Section 1: Common Functions

1.1 Multiple Settings Groups

Alternate settings groups can be used to reconfigure the relay during significant changes to system conditions e.g.

Primary plant switching in/out.

Summer/winter or day/night settings.

switchable earthing connections.

Loss of Grid connection (see below)

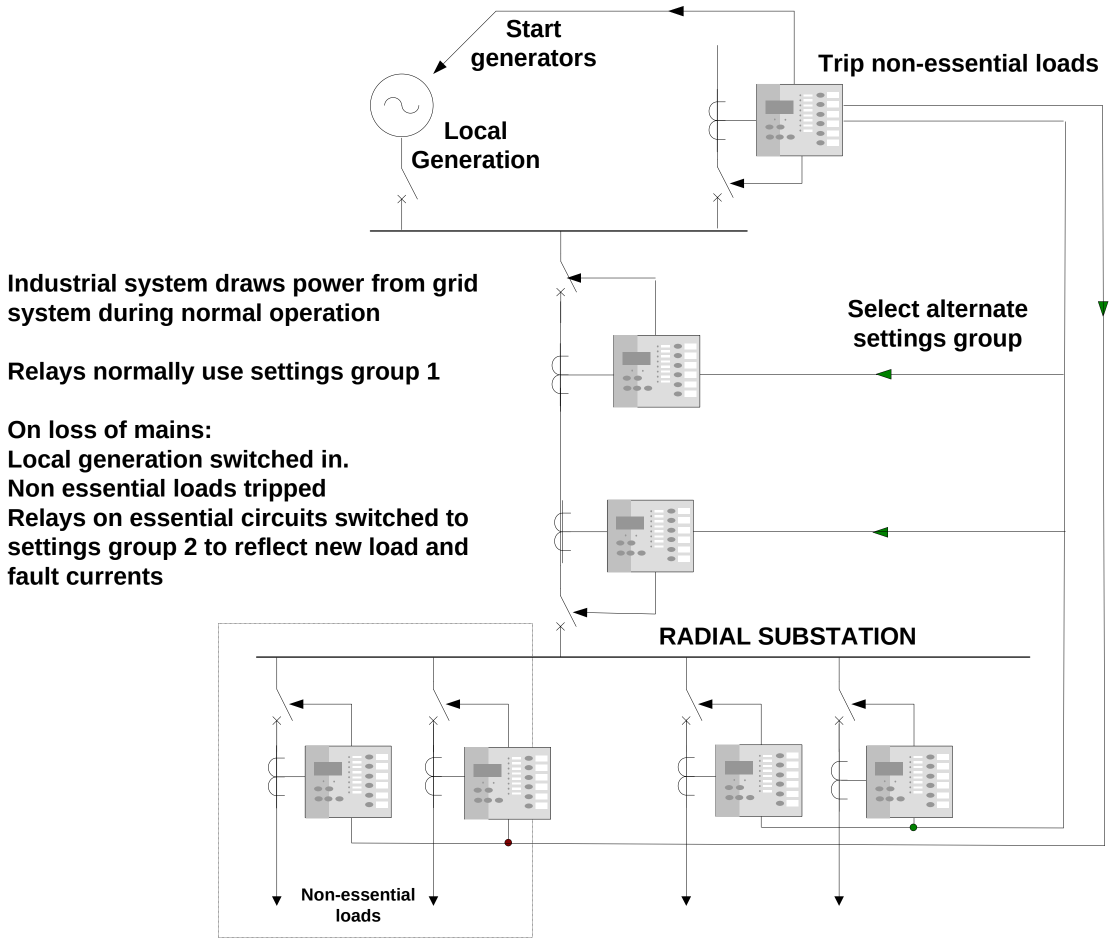


Figure 1.1-1 Example Use of Alternative Settings Groups

1.2 Binary Inputs

Each Binary Input (BI) can be programmed to operate one or more of the relay functions, LEDs or output relays. These could be used to bring such digital signals as Inhibits for protection elements, the trip circuit supervision status, autoreclose control signals etc. into the Relay.

1.2.1 Alarm and Tripping Inputs

A common use of binary inputs is to use the 7SR224 to provide indication of alarm or fault conditions from an external device which does not itself provide indication or recording facilities. The Binary Inputs are mapped to LED(s), waveform storage trigger and binary outputs. Note that external device outputs which require high speed tripping, should be wired to a binary input to provide LED indication and also have a parallel connection wired to directly trip the circuit via a blocking diode, see fig. 1.2-1:

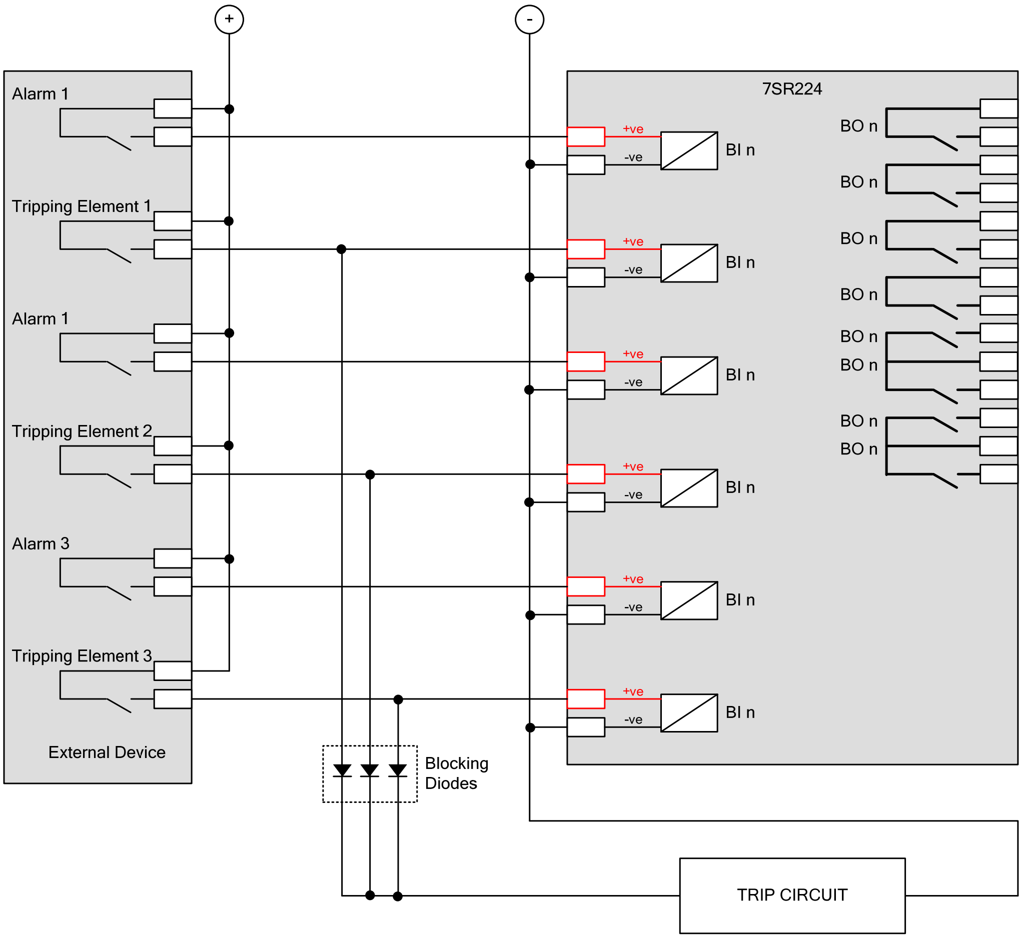


Figure 1.2-1 Example of External Device Alarm and Trip Wiring

1.2.2 Control and tripping circuits

Where a binary input is used to as part of a control function, for example tripping or closing a circuit breaker, it may be desirable to provide an enhanced level of immunity to prevent maloperation due to induced voltages. This is most important where cross-site cabling is involved, as this is susceptible to induced voltages and will contribute to capacitive discharge currents under DC system earth fault conditions.

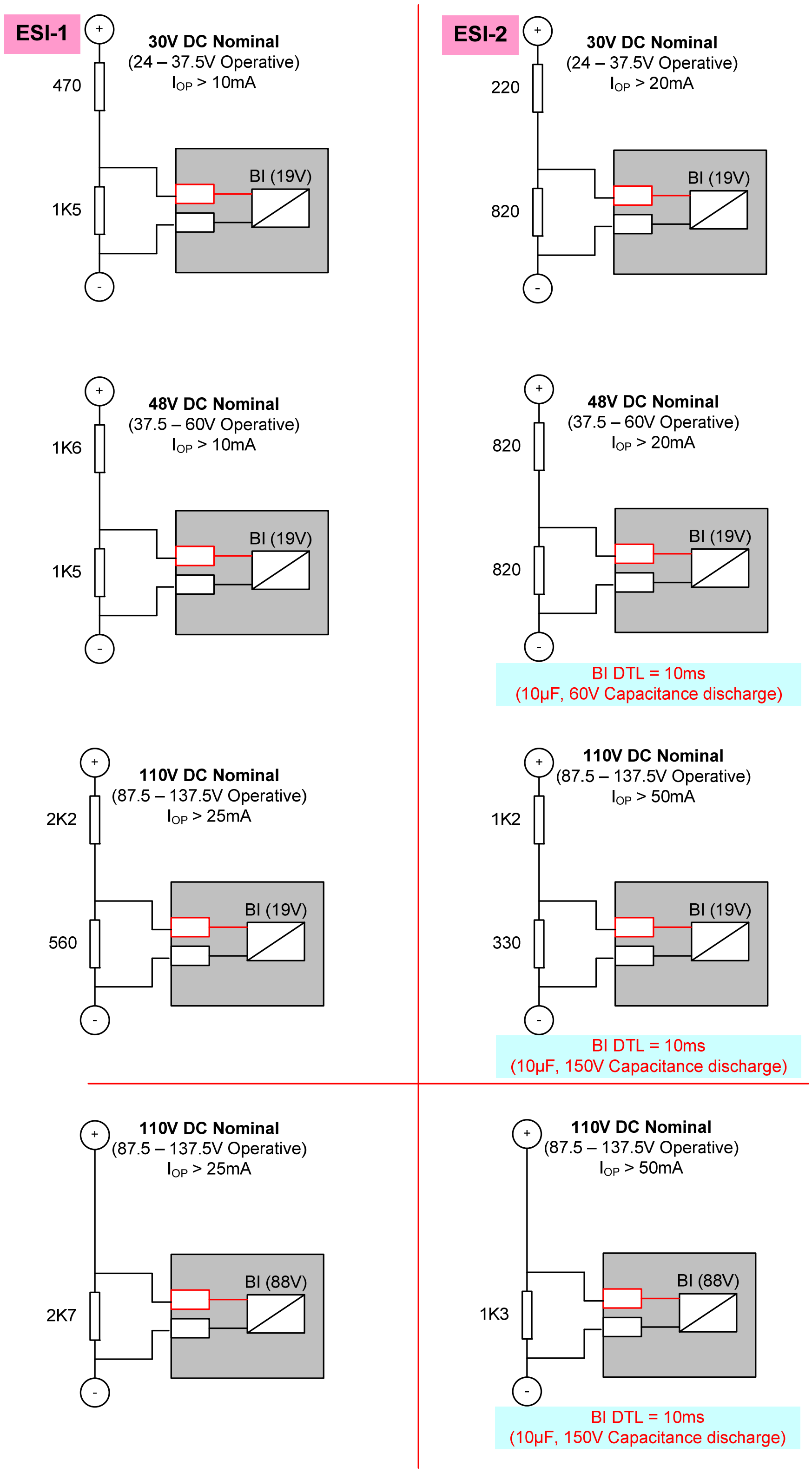
One method of enhancing the immunity of the binary input is to switch both positive and negative connections; however this is often not possible or desirable.

Where the battery voltage allows its use, the 88V binary input will give an added measure of immunity, compared to the 19V binary input, due to its higher minimum pickup voltage.

As a guide to suitable degrees of enhanced immunity, we have adopted the parameters laid down in U.K. standard EATS 48-4. This standard identifies two levels of immunity: Category ESI 1 may be adopted for connections which do not include significant wiring runs or cabling outside the relay enclosure. Category ESI 2 should be used for connections which include significant wiring runs or cabling outside the relay enclosure. This category also gives immunity to capacitive discharge currents.

The following diagrams show the external resistors which should be fitted to allow the binary input to comply with either of the above categories. Fitting these components will raise the current required to operate the binary input, and hence makes it less susceptible to maloperation.

Where required, the minimum pickup delay for the binary input is stated on the diagram.



Resistor power ratings:	30V DC Nominal	>3W
	48V DC Nominal	>3W
	110V DC Nominal	>10W (ESI- 1)
	110V DC Nominal	>20W (ESI-2)

Resistors must be wired with crimped connections as they may run hot

Figure 1.2-2 – Binary Input Configurations Providing Compliance with EATS 48-4 Classes ESI 1 and ESI 2

1.3 Binary Outputs

Binary Outputs are mapped to output functions by means of settings. These could be used to bring out such digital signals as trips, a general pick-up, plant control signals etc.

All Binary Outputs are Trip rated

Each can be defined as Self or Hand Reset. Self-reset contacts are applicable to most protection applications. Hand-reset contacts are used where the output must remain active until the user expressly clears it e.g. in a control scheme where the output must remain active until some external feature has correctly processed it.

Case contacts 26 and 27 will automatically short-circuit when the relay is withdrawn from the case. This can be used to provide an alarm that the Relay is out of service.

Notes on Self Reset Outputs

With a failed breaker condition the relay may remain operated until current flow in the primary system is interrupted by an upstream device. The relay will then reset and attempt to interrupt trip coil current flowing through an output contact. Where this level is above the break rating of the output contact an auxiliary relay with heavy-duty contacts should be utilised.

1.4 LEDs

Output-function LEDs are mapped to output functions by means of settings. These could be used to display such digital signals as trips, a general pick-up, plant control signals etc.

User Defined Function LEDs are used to indicate the status of Function Key operation. These do not relate directly to the operation of the Function Key but rather to its consequences. So that if a Function Key is depressed to close a Circuit-Breaker, the associated LED would show the status of the Circuit-Breaker closed Binary Input.

Each LED can be defined as Self or Hand Reset. Hand reset LEDs are used where the user is required to expressly acknowledge the change in status e.g. critical operations such as trips or system failures. Self-reset LEDs are used to display features which routinely change state, such as Circuit-Breaker open or close.

The status of hand reset LEDs is retained in capacitor-backed memory in the event of supply loss.

1.5 Phase Allocation and Rotation

Settings are provided in the *CT/VT Config* menu to allow the phase letter references to be allocated to any of the three physical current or voltage input channels. This means that the three Recloser mechanisms 1, 2 and 3 can be pre-wired to the controller inputs V_1 V_2 V_3 and I_1 I_2 I_3 and the phase references A, B and C can be allocated later during commissioning when settings are installed to suit customer requirements. This feature allows for physical transposing of phases and different direction orientation of the Recloser installation without changes to secondary wiring and simply allocates the physical connections to be selected by the controller. If this setting is set incorrectly, metering and instrumentation will be incorrect and protection operation may be affected.

The electrical (phasor) sequence can also be selected as A-B-C or A-C-B by a separate setting. This setting is used to select the positive phasor rotation sequence as either standard (A-B-C) or reverse sequence (A-C-B). If this setting is set incorrectly, directional polarizing of overcurrent protection will be incorrect and cause incorrect directional operation. Negative and positive sequence components will also be exchanged, for both current and voltage. This will cause incorrect metering as well as distortion to elements utilizing these components for measurement or polarizing.

Section 2: Protection Functions

2.1 Time delayed overcurrent (51/51G/51N)

The 51-n characteristic element provides a number of time/current operate characteristics. The element can be defined as either an Inverse Definite Minimum Time Lag (IDMTL) or Definite Time Lag (DTL) characteristic. If an IDMTL characteristic is required, then IEC, ANSI/IEEE and a number of manufacturer specific curves are supported.

IDMTL characteristics are defined as “Inverse” because their tripping times are inversely proportional to the Fault Current being measured. This makes them particularly suitable to grading studies where it is important that only the Relay(s) closest to the fault operate. Discrimination can be achieved with minimised operating times.

To optimise the grading capability of the relay additional time multiplier, ‘Follower DTL’ (Fig. 2.1-1) or ‘Minimum Operate Time’ (Fig. 2.1-2) settings can be applied.

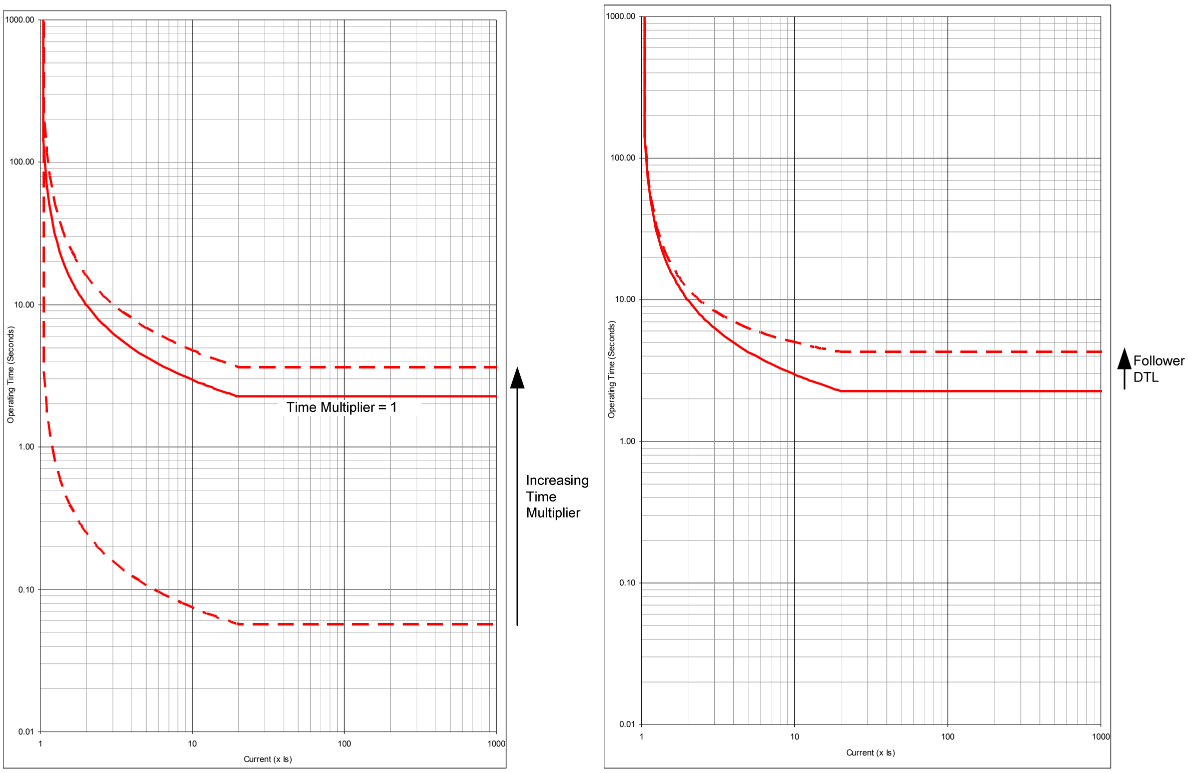


Figure 2.1-1 IEC NI Curve with Time Multiplier and Follower DTL Applied

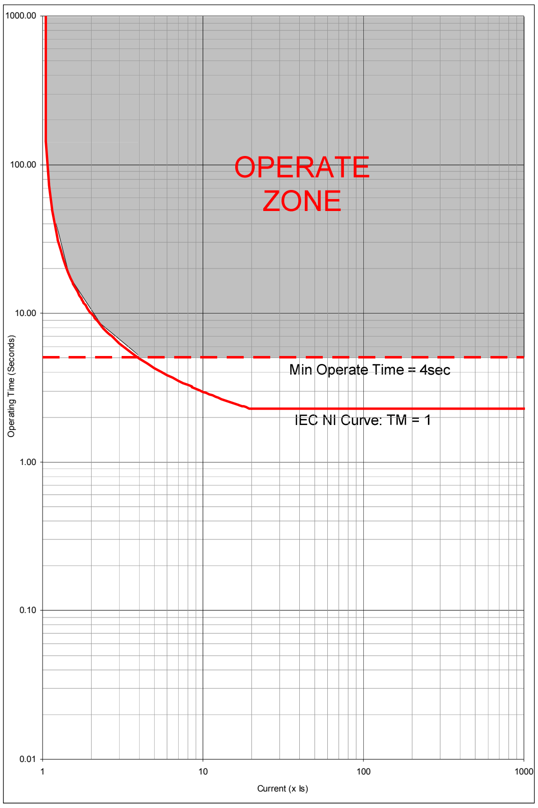


Figure 2.1-2 IEC NI Curve with Minimum Operate Time Setting Applied

To increase sensitivity, dedicated Earth fault elements are used. There should be little or no current flowing to earth in a healthy system so such relays can be given far lower pick-up levels than relays which detect excess current (> load current) in each phase conductor. Such dedicated earth fault relays are important where the fault path to earth is a high-resistance one (such as in highly arid areas) or where the system uses high values of earthing resistor / reactance and the fault current detected in the phase conductors will be limited.

2.1.1 Selection of Overcurrent Characteristics

Each pole has two independent over-current characteristics. Where required the two curves can be used:

To produce a composite curve

To provide a two stage tripping scheme

Where one curve is to be directionalised in the forward direction the other in the reverse direction.

The characteristic curve shape is selected to be the same type as the other relays on the same circuit or to grade with items of plant e.g. fuses or earthing resistors.

The application of IDMTL characteristic is summarised in the following table:

OC/EF Curve Characteristic	Application
IEC Normal Inverse (NI) ANSI Moderately Inverse (MI)	Generally applied
IEC Very Inverse (VI) ANSI Very Inverse (VI)	Used with high impedance paths where there is a significant difference between fault levels at protection points
IEC Extreme Inversely (EI) ANSI Extremely Inverse (EI)	Grading with Fuses
IEC Long Time Inverse (LTI)	Used to protect transformer earthing resistors having long withstand times
Recloser Specific	Use when grading with specific recloser

Table 2-1 Application of IDMTL Characteristics

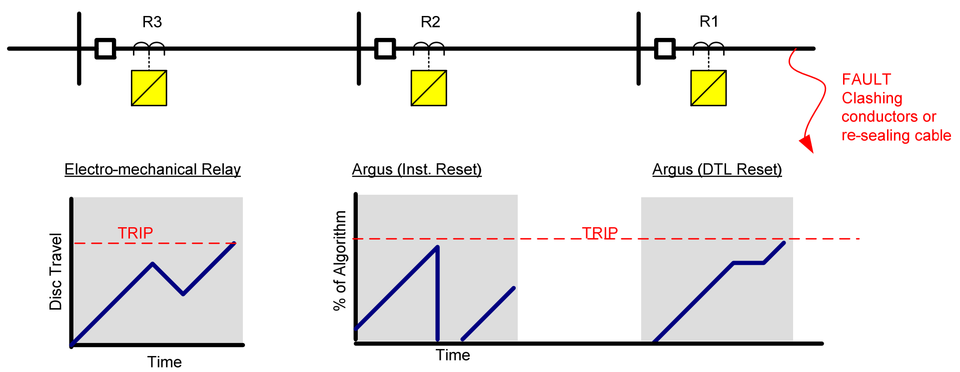
2.1.2 Reset Delay

The increasing use of plastic insulated cables, both conventionally buried and aerial bundled conductors, have given rise to the number of flashing intermittent faults on distribution systems. At the fault position, the plastic melts and temporarily reseals the faulty cable for a short time after which the insulation fails again. The same phenomenon has occurred in compound-filled joint boxes or on ‘clashing’ overhead line conductors. The repeating process of the fault can cause electromechanical disc relays to “ratchet” up and eventually trip the faulty circuit if the reset time of the relay is longer than the time between successive faults.

To mimic an electromechanical relay the relay can be user programmed for an ANSI DECAYING characteristic when an ANSI operate characteristic is applied. Alternatively a DTL reset (0 to 60 seconds) can be used with other operate characteristics.

For protection of cable feeders, it is recommended that a 60 second DTL reset be used.

On overhead line networks, particularly where reclosers are incorporated in the protected system, instantaneous resetting is desirable to ensure that, on multiple shot reclosing schemes, correct grading between the source relays and the relays associated with the reclosers is maintained.



2.2 Voltage dependent overcurrent (51V)

Reduced voltage can indicate a fault on the system, it can be used to make the 51 elements more sensitive.

Typically Voltage Dependent Over-current (51V) is applied to:

Transformer Incomers: Where the impedance of the transformer limits fault current the measured voltage level can be used to discriminate between load and fault current.

Long lines: Where the impedance of the line limits fault current the measured voltage level can be used to discriminate between load and fault current.

Generator circuits: When a Generator is subjected to a short circuit close to its terminals the short-circuit current follows a complex profile. After the initial "sub-transient" value, generally in the order of 7 to 10 times full load current, it falls rapidly (around 10 to 20ms) to the "transient" value. This is still about 5 to 7 times full load and would be sufficient to operate the protection's over-current elements. However the effect on armature reactance of the highly inductive short-circuit current is to increase significantly the internal impedance to the synchronous reactance value. If the Automatic Voltage Regulation (AVR) system does not respond to increase the excitation, the fault current will decay over the next few seconds to a value below the full load current. This is termed the steady state fault current, determined by the Generator's synchronous reactance (and pre-fault excitation). It will be insufficient to operate the protection's over-current elements and the fault will not be detected. Even if AVR is active, problems may still be encountered. The AVR will have a declared minimum sustained fault current and this must be above the protection over-current settings. Close-in short circuit faults may also cause the AVR to reach its safety limits for supplying maximum excitation boost, in the order of several seconds, and this will result in AVR internal protection devices such as diode fuses to start operating. The generator excitation will then collapse, and the situation will be the same as when no AVR was present. The fault may again not be detected.

Current grading remains important since a significant voltage reduction may be seen for faults on other parts of the system. An inverse time operating characteristic must therefore be used.

The VDO Level - the voltage setting below which the more sensitive operating curve applies - must be set low enough to discriminate between short-circuits and temporary voltage dips due to overloads. However, it must also be high enough to cover a range of voltage drops for different circuit configurations, from around 0.6Vn to almost zero. Typically it will be set in the range 0.6 to 0.8Vn.

2.3 Cold Load Settings (51c)

Once a Circuit-Breaker has been open for a period of time ed, higher than normal levels of load current may flow following CB re-closure e.g. heating or refrigeration plant. The size and duration of this current is dependent upon the type of load and the time that the CB is open.

The feature allows the relay to use alternative Shaped Overcurrent (51c) settings when a Cold Load condition is identified. The cold load current and time multiplier settings will normally be set higher than those of the normal overcurrent settings.

The relay will revert to its usual settings (51-n) after elapse of the cold load period. This is determined either by a user set delay, or by the current in all 3-phases falling below a set level (usually related to normal load levels) for a user set period.

2.4 Instantaneous Overcurrent (50/50G/50N)

Each instantaneous element has an independent setting for pick-up current and a follower definite time lag (DTL) which can be used to provide time grading margins, sequence co-ordination grading or scheme logic. The “instantaneous” description relates to the pick-up of the element rather than its operation.

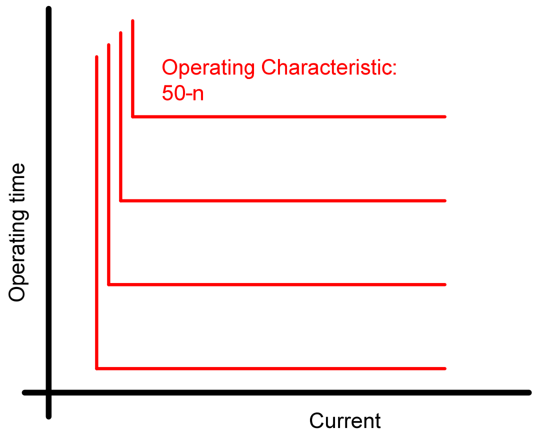


Figure 2.4-1 General Form of DTL Operate Characteristic

Instantaneous elements can be used in current graded schemes where there is a significant difference between the fault current levels at different relay point. The Instantaneous element is set to pick up at a current level above the maximum Fault Current level at the next downstream relay location, and below its own fault current level. The protection is set to operate instantaneously and is often termed ‘Highset Overcurrent’. A typical application is the protection of transformer HV connections – the impedance of the transformer ensuring that the LV side has a much lower level of fault current.

The 50-n elements have a very low transient overreach i.e. their accuracy is not appreciably affected by the initial dc offset transient associated with fault inception.

2.4.1 Blocked Overcurrent Protection Schemes

A combination of instantaneous and DTL elements can be used in blocked overcurrent protection schemes. These protection schemes are applied to protect substation busbars or interconnectors etc. Blocked overcurrent protection provides improved fault clearance times when compared against normally graded overcurrent relays.

The blocked overcurrent scheme of busbar protection shown in Figure 2.2-2 illustrates that circuit overcurrent and earth fault protection relays can additionally be configured with busbar protection logic.

The diagram shows a substation. The relay on the incomer is to trip for busbar faults (F1) but remain inoperative for circuit faults (F2).

In this example the overcurrent and earth fault settings for the incomer 50-1 element are set to below the relevant busbar fault levels. 50-1 time delay is set longer than it would take to acknowledge receipt of a blocking signal from an outgoing circuit.

Close up faults on the outgoing circuits will have a similar fault level to busbar faults. As the incomer 50-1 elements would operate for these faults it is necessary to provide a blocking output from the circuit protections. The 50-1 elements of the output relays are given lower current settings than the incomer 50-1 settings, the time delay is set to 0ms. The output is mapped to a contact. The outgoing relay blocking contacts of all circuits are wired in parallel and this wiring is also connected to a BI on the incomer relay. The BI on the incomer relay is mapped to block its 50-1 element.

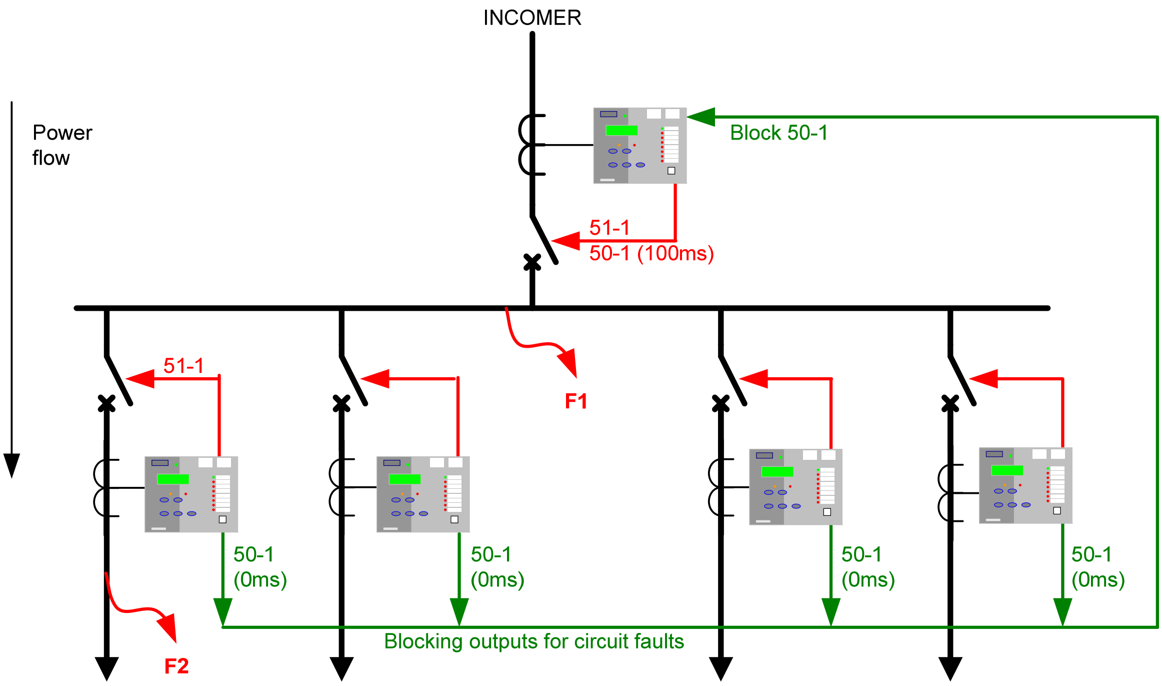


Figure 2.4-2 Blocking Scheme Using Instantaneous Overcurrent Elements

Typically a time delay as low as 50ms on the incomer 50-1 element will ensure that the incomer is not tripped for outgoing circuit faults. However, to include for both equipment tolerances and a safety margin a minimum time delay of 100ms is recommended.

This type of scheme is very cost effective and provides a compromise between back-up overcurrent busbar protection and dedicated schemes of busbar protection.

Instantaneous elements are also commonly applied to autoreclose schemes to grade with downstream circuit reclosers and maximise the probability of a successful auto-reclose sequence – see section 4

2.5 Sensitive Earth-fault Protection (50SEF)

Earth fault protection is based on the assumption that fault current levels will be limited only by the earth fault impedance of the line and associated plant. However, it may be difficult to make an effective short circuit to earth due to the nature of the terrain e.g. dry earth, desert or mountains. The resulting earth fault current may therefore be limited to very low levels.

Sensitive earth fault (SEF) protection is used to detect such faults. This range of relays have a low burden, so avoiding unacceptable loading of the CTs at low current settings.
SEF provides a backup to the main protection. A DTL characteristic with a time delay of several seconds is typically applied ensuring no interference with other discriminative protections. A relatively long time delay can be tolerated since fault current is low and it is impractical to grade SEF protection with other earth fault protections. Although not suitable for grading with other forms of protection SEF relays may be graded with each other.

Where very sensitive current settings are required then it is preferable to use a core balance CT rather than wire into the residual connection of the line CTs. The turns ratio of a core balance CT can be much smaller than that of phase conductors as they are not related to the rated current of the protected circuit and are not required to measure the higher currents associated with phase to phase faults. Since only one core is used, the CT magnetising current losses are also reduced by a factor of three. If a core balance CT is applied to a network where high earth fault currents can occur, these currents can cause saturation of the core leading to reduced CT output. In this case it is recommended that the SEF protection is applied with support from Earth Fault protection with less sensitive settings. This lower level of sensitivity is easily achieved by Derived Earth Fault protection which uses the calculated sum of the three phase currents as its operating quantity. The 7SR224 provides this feature by allowing the 50/51G Measured earth fault elements to alternatively use a calculated quantity whilst the 50/51SEF elements use the I_4 measured quantity.

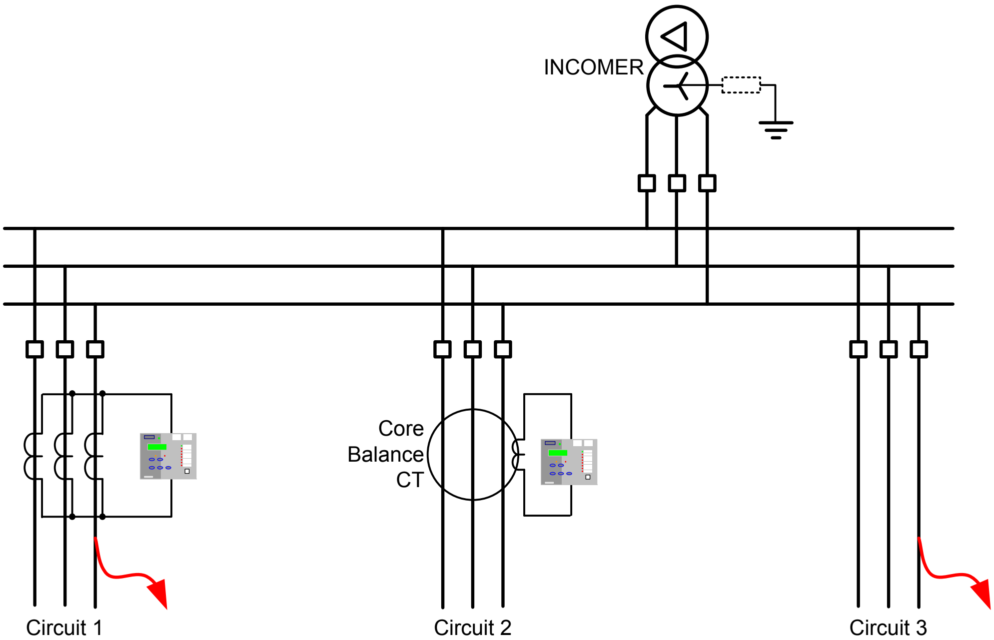


Figure 2.5-1 Sensitive Earth Fault Protection Application

There are limits to how sensitive an SEF relay may be set since the setting must be above any line charging current levels that can be detected by the relay. On occurrence of an out of zone earth fault e.g. on circuit 3 the elevation of sound phase voltage to earth in a non-effectively earthed system can result in a zero sequence current of up 3 times phase charging current flowing through the relay location.

The step change from balanced 3-phase charging currents to this level of zero sequence current includes transients. It is recommended to allow for a transient factor of 2 to 3 when determining the limit of charging current. Based on the above considerations the minimum setting of a relay in a resistance earthed power system is 6 to 9 times the charging current per phase.

2.6 Directional Protection (67)

Each overcurrent stage can operate for faults in either forward or reverse direction. Convention dictates that forward direction refers to power flow away from the busbar, while reverse direction refers to power flowing towards the busbar.

The directional phase fault elements, 67/50 and 67/51, work with a Quadrature Connection to prevent loss of polarising quantity for close-in phase faults. That is, each of the current elements is directionalised by a voltage derived from the other two phases.

This connection introduces a 90° Phase Shift (Current leading Voltage) between reference and operate quantities which must be allowed for in the Characteristic Angle setting. This is the expected fault angle, sometimes termed the Maximum Torque Angle (MTA) as an analogy to older Electro-mechanical type relays

Example: Expected fault angle is -30º (Current lagging Voltage) so set Directional Angle to: +90° -30° = +60°.

A fault is determined to be in the selected direction if its phase relationship lies within a quadrant +/- 85° either side of the Characteristic Angle setting.

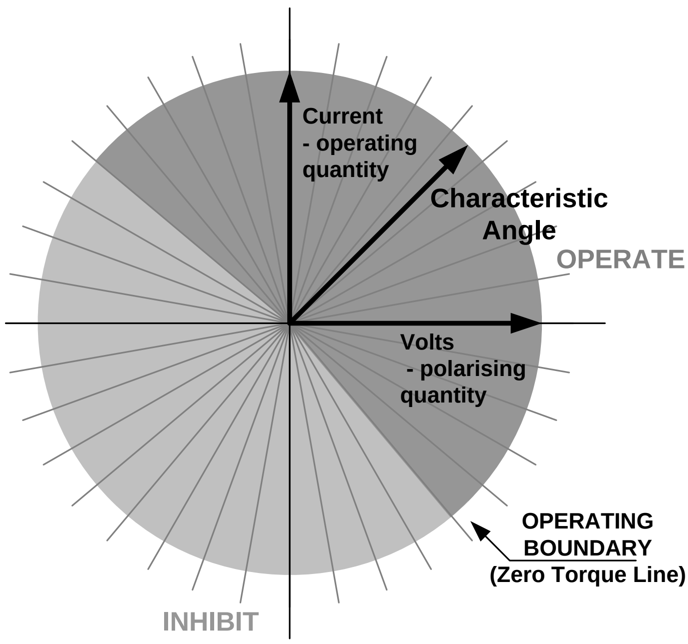


Figure 2.6-1 Directional Characteristics

A number of studies have been made to determine the optimum MTA settings e.g. W.K Sonnemann's paper "A Study of Directional Element Connections for Phase Relays". Figure 2 10 shows the most likely fault angle for phase faults on Overhead Line and Cable circuits.

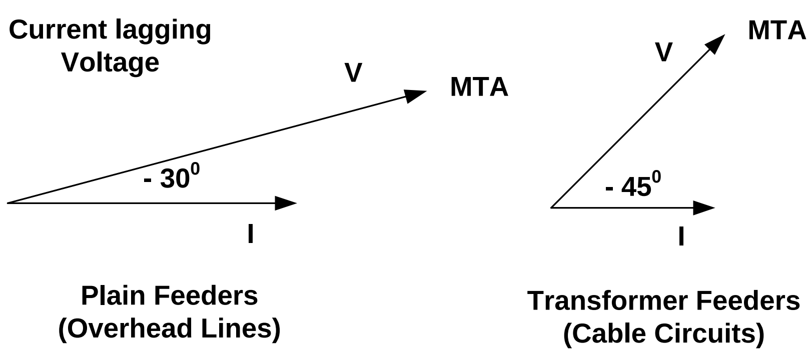


Figure 2.6-2 Phase Fault Angles

Directional overcurrent elements allow greater fault selectivity than non-directional elements for interconnected systems where fault current can flow in both directions through the relaying point. Consider the network shown in fig. 2.6-3.

The Circuit breakers at A, B, E and G have directional overcurrent relays fitted since fault current can flow in both directions at these points. The forward direction is defined as being away from the busbar and against the direction of normal load current flow. These forward looking IDMTL elements can have sensitive settings applied i.e. low current and time multiplier settings. Note that 7SR22 relays may be programmed with forward, reverse and non-directional elements simultaneously when required by the protection scheme.

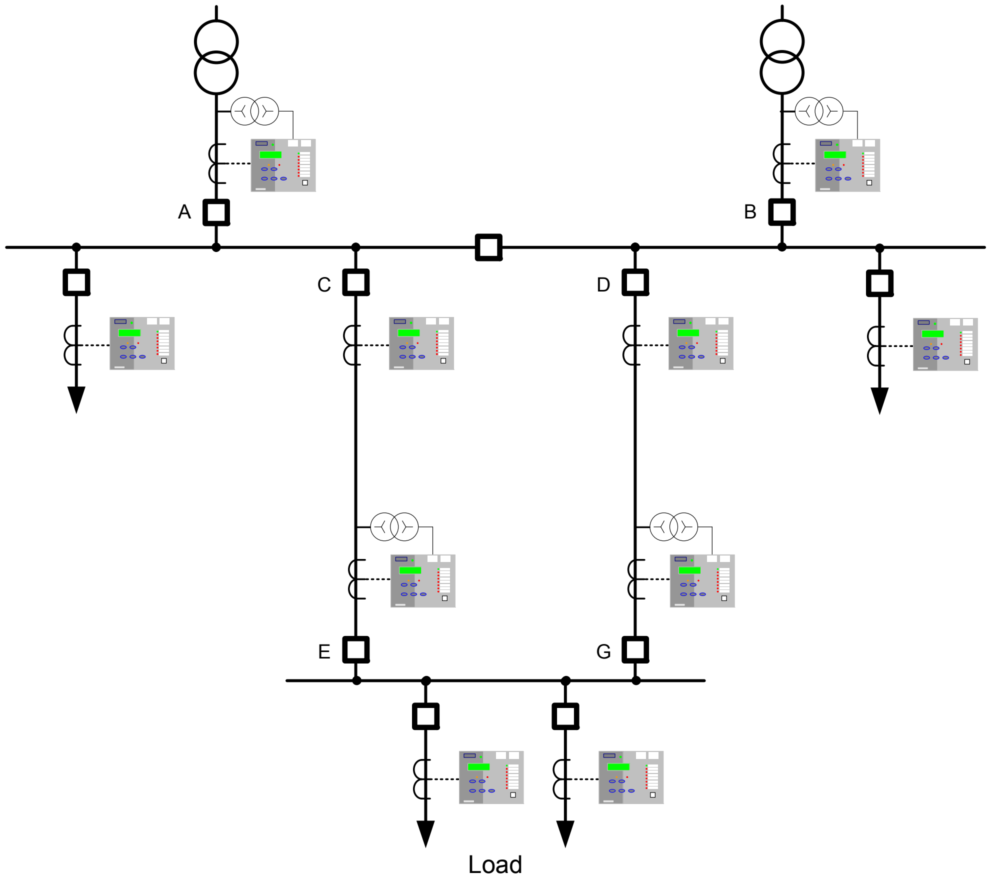


Figure 2.6-3 Application of Directional Overcurrent Protection

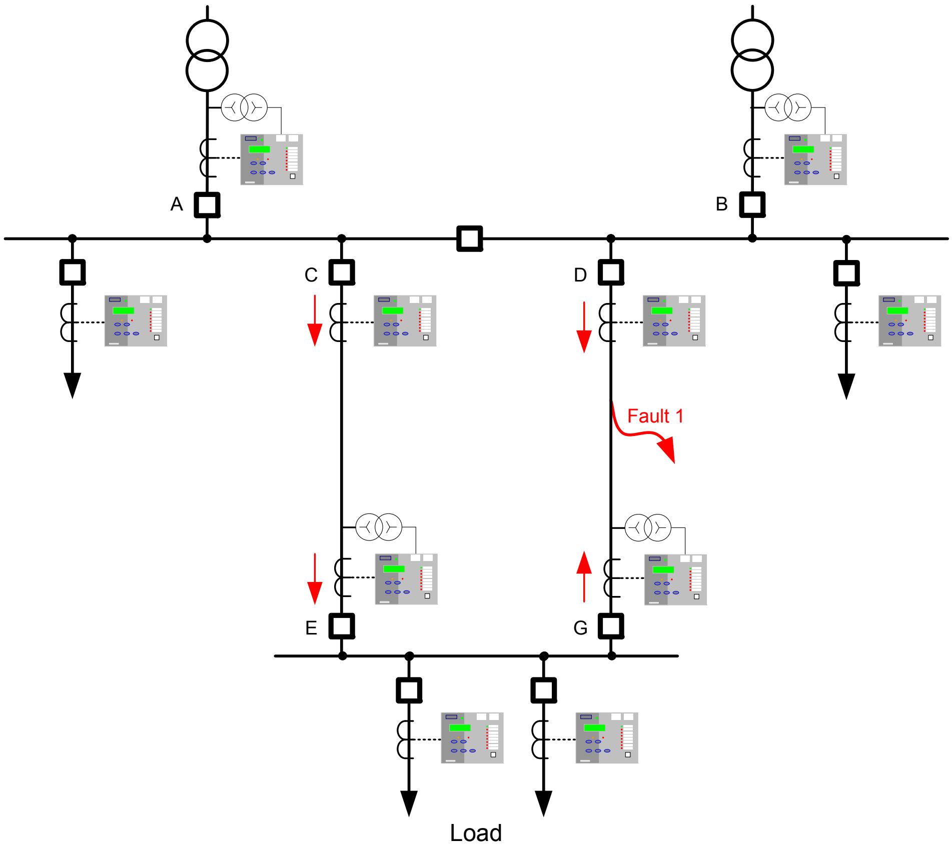


Figure 2.6-4 Feeder Fault on Interconnected Network

Considering the D-G feeder fault shown in fig. 2.6-4: the current magnitude through breakers C and D will be similar and their associated relays will similar prospective operate times. To ensure that only the faulted feeder is isolated G FWD must be set to be faster than C. Relay G will thus Trip first on FWD settings, leaving D to operate to clear the fault. The un-faulted Feeder C-E maintains power to the load.

Relays on circuits C and D at the main substation need not be directional to provide the above protection scheme. However additional directional elements could be mapped to facilitate a blocked overcurrent scheme of busbar protection.

At A and B, forward looking directional elements enable sensitive settings to be applied to detect transformer faults whilst reverse elements can be used to provide back-up protection for the relays at C and D.

By using different settings for forward and reverse directions, closed ring circuits can be set to grade correctly whether fault current flows in a clockwise or counter clockwise direction i.e. it may be practical to use only one relay to provide dual directional protection.

2.6.1 2 Out of 3 Logic

Sensitive settings can be used with directional overcurrent relays since they are directionalised in a way which opposes the flow of normal load current i.e. on the substation incomers as shown on fig. 2.6-4. However on occurrence of transformer HV or feeder incomer phase-phase faults an unbalanced load current may still flow as an un balanced driving voltage is present. This unbalanced load current during a fault may be significant where sensitive overcurrent settings are applied - the load current in one phase may be in the operate direction and above the relay setting.

Where this current distribution may occur then the relay is set to CURRENT PROTECTION>PHASE OVERCURRENT> ***67 2-out-of-3 Logic*** **= ENABLED**

Enabling 2-out-of-3 logic will prevent operation of the directional phase fault protection for a single phase to earth fault. Dedicated earth-fault protection should therefore be used if required.

2.7 Directional Earth-Fault (50/51G, 50/51N, 51/51SEF)

The directional earth-fault elements, either measure directly or derive from the three line currents the zero sequence current (operate quantity) and compare this against the derived zero phase sequence voltage (polarising quantity). Section 1 of the Technical Manual 'Description of Operation' details the method of measurement. The required setting is entered directly as dictated by the system impedances.

Example: Expected fault angle is -45° (i.e. residual current lagging residual voltage) therefore ***67G Char Angle* = -45°**

However directional earth elements can be selectable to use either ZPS or NPS Polarising. This is to allow for the situation where ZPS voltage is not available; perhaps because a 3-limb VT is being used. Care must be taken as the Characteristic Angle will change if NPS Polarising is used.

Once again the fault angle is completely predictable, though this is a little more complicated as the method of earthing must be considered.

MTA (I wrt V)				
0^0	-15^0	-45^0	-65^0	-90^0
← Resistive Neutral			Reactive Neutral →	

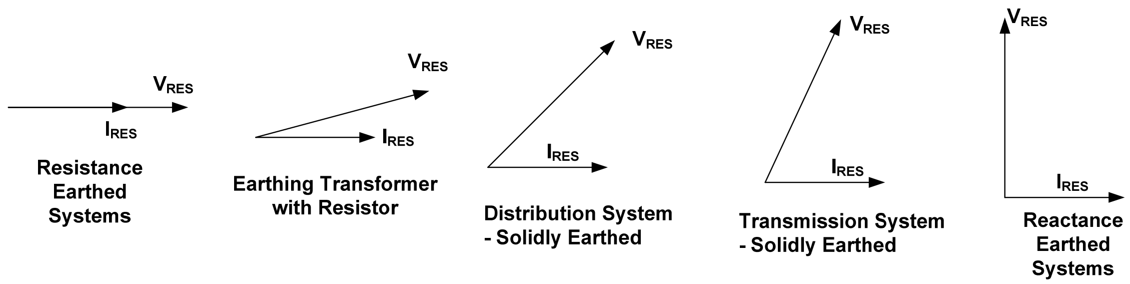


Figure 2.7-1 Earth Fault Angles

2.8 High Impedance Restricted Earth Fault Protection (64H)

Restricted Earth Fault (REF) protection is applied to Transformers to detect low level earth faults in the transformer windings. Current transformers are located on all connections to the transformer. During normal operation or external fault conditions no current will flow in the relay element. When an internal earth fault occurs, the currents in the CTs will not balance and the resulting unbalance flows through the relay.

The current transformers may saturate when carrying high levels of fault current. The high impedance name is derived from the fact that a resistor is added to the relay leg to prevent relay operation due to CT saturation under through fault conditions.

The REF Trip output is configured to provide an instantaneous trip output from the relay to minimise damage from developing winding faults.

The application of the element to a Delta-Star transformer is shown in Figure 2-5. Although the connection on the delta winding is more correctly termed a Balanced Earth-Fault element, it is still usually referred to as Restricted Earth Fault because of the presence of the transformer.

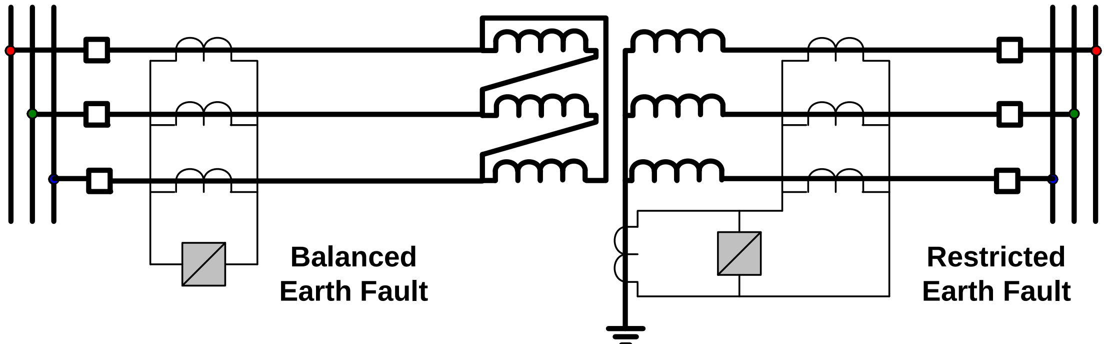


Figure 2.8-1 Balanced and Restricted Earth-fault protection of Transformers

The calculation of the value of the Stability Resistor is based on the worst case where one CT fully saturates and the other balancing CT does not saturate at all. A separate Siemens Protection Devices Limited Publication is available covering the calculation procedure for REF protection. To summarise this:

The relay Stability (operating) Vs voltage is calculated using worst case lead burden to avoid relay operation for through-fault conditions where one of the CTs may be fully saturated. The required fault setting (primary operate current) of the protection is chosen; typically, this is between 10 % and 25 % of the protected winding rated current. The relay setting current is calculated based on the secondary value of the operate current, note, however, that the summated CT magnetising current @ Vs must be subtracted to obtain the required relay operate current setting.

Since the relay operate current setting and stability/operating voltage are now known, a value for the series resistance can now be calculated.

A check is made as to whether a Non-Linear Resistor is required to limit scheme voltage during internal fault conditions – typically where the calculated voltage is in excess of 2kV.

The required thermal ratings for external circuit components are calculated.

Composite overcurrent and REF protection can be provided using a multi-element relay as.

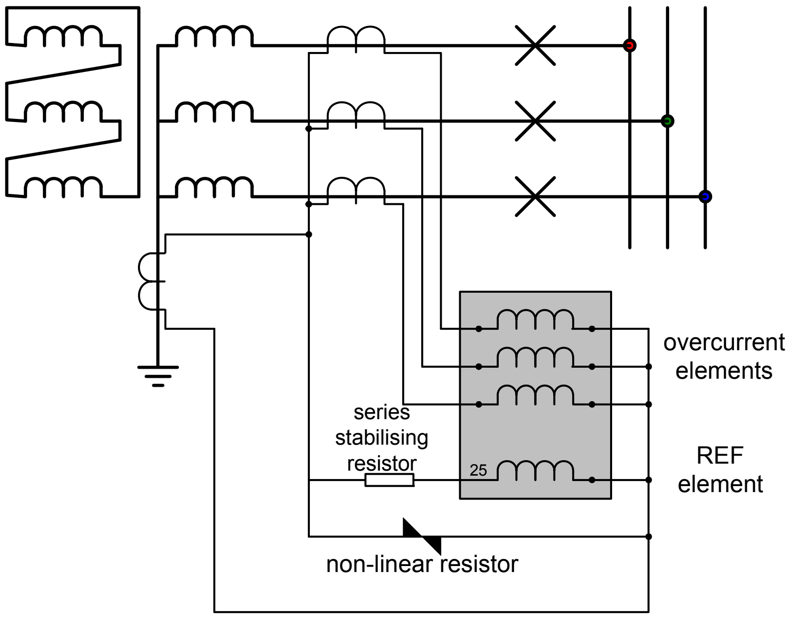


Figure 2.8-2   Composite Overcurrent and Restricted Earth-fault Protection

Although core-balance CTs are traditionally used with elements requiring sensitive pickup settings, cost and size usually precludes this on REF schemes. Instead single-Phase CTs are used and their secondary's connected in parallel.

Where sensitive settings are required, the setting must be above any line charging current levels that can be detected by the relay.

On occurrence of an out of zone earth fault the elevation of sound phase voltage to earth in a non-effectively earthed system can result in a zero sequence current of up 3 times phase charging current flowing through the relay location.

The step change from balanced 3-phase charging currents to this level of zero sequence current includes transients. It is recommended to allow for a transient factor of 2 to 3 when determining the limit of charging current. Based on the above considerations the minimum setting of a relay in a resistance earthed power system is 6 to 9 times the charging current per phase.

High impedance differential protection is suitable for application to auto transformers as line currents are in phase and the secondary current through the relay is balanced to zero by the use of CTs ratios at all three terminals. High impedance protection of this type is very sensitive and fast operating for internal faults.

2.9 Negative Phase Sequence Overcurrent (46NPS)

The presence of Negative Phase Sequence (NPS) current indicates an unbalance in the phase currents, either due to a fault or unbalanced load.

NPS current presents a major problem for 3-phase rotating plant. It produces a reaction magnetic field which rotates in the opposite direction, and at twice the frequency, to the main field created by the DC excitation system. This induces double-frequency currents into the rotor which cause very large eddy currents in the rotor body. The resulting heating of the rotor can be severe and is proportional to $(I_2)^2$ t.

Generators and Motors are designed, manufactured and tested to be capable of withstanding unbalanced current for specified limits. Their withstand is specified in two parts; continuous capability based on a figure of I_2, and short time capability based on a constant, K, where K = $(I_2)^2$ t. NPS overcurrent protection is therefore configured to match these two plant characteristics.

2.10 Undercurrent (37)

Undercurrent elements are used in control logic schemes such as Auto-Changeover Schemes, Auto-Switching Interlock and Loss of Load. They are used to indicate that current has ceased to flow or that a low load situation exists. For this reason simple Definite Time Lag (DTL) elements may be used.

For example, once it has been determined that fault current has been broken – the CB is open and no current flows – an auto-isolation sequence may safely be initiated.

2.11 Thermal Overload (49)

The element uses measured 3-phase current to estimate the real-time Thermal State, θ, of cables or transformers. The Thermal State is based on both past and present current levels.

θ = 0% for unheated equipment, and θ = 100% for maximum thermal withstand of equipment or the Trip threshold.

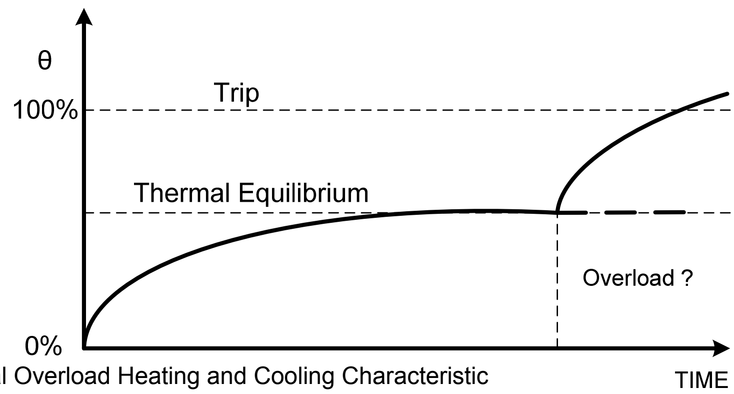


Figure 2.11-1 Thermal Overload Heating and Cooling Characteristic

For given current level, the Thermal State will ramp up over time until Thermal Equilibrium is reached when Heating Effects of Current = Thermal Losses.

The heating / cooling curve is primarily dependant upon the Thermal Time Constant. This must be matched against that quoted for the item of plant being protected. Similarly the current tripping threshold, I_θ , is related to the thermal withstand of the plant.

Thermal Overload is a slow acting protection, detecting faults or system conditions too small to pick-up fast acting protections such as Phase Overcurrent. An Alarm is provided for θ at or above a set % of capacity to indicate that a potential trip condition exists and that the system should be scrutinised for abnormalities.

2.12 Under/Over Voltage Protection (27/59)

Power system under-voltages on may occur due to:

System faults.

An increase in system loading,

Non-energized power system e.g. loss of an incoming transformer

During normal system operating conditions regulating equipment such as transformer On Load Tap Changers (OLTC) and generator Automatic Voltage Regulators (AVR) ensure that the system runs within acceptable voltage limits.

7SR24 undervoltage/DTL elements can be used to detect abnormal undervoltage conditions due to system overloads. Binary outputs can be used to trip non-essential loads - returning the system back to its normal operating levels. This ‘load shedding’ should be initiated via time delay elements so avoiding operation during transient disturbances. An under voltage scheme (or a combined under frequency/under voltage scheme) can provide faster tripping of non-essential loads than under-frequency load shedding so minimising the possibility of system instability.

Where a transformer is supplying 3-phase motors a significant voltage drop e.g. to below 80% may cause the motors to stall. An undervoltage element can be set to trip motor circuits when the voltage falls below a preset value so that on restoration of supply an overload is not caused by the simultaneous starting of all the motors. A time delay is required to ensure voltage dips due to remote system faults do not result in an unnecessary disconnection of motors.

To confirm presence/loss of supply, the voltage elements should be set to values safely above/below that where a normal system voltage excursion can be expected. The switchgear/plant design should be considered. The ‘Dead’ level may be very near to the ‘live’ level or may be significantly below it. The variable hysteresis setting allows the relay to be used with all types of switchgear.

System over-voltages can damage component insulation. Excessive voltage may occur for:

Sudden loss of load

A tap changer run-away condition occurs in the high voltage direction,

Generator AVR equipment malfunctions or

Reactive compensation control malfunctions.

System regulating equipment such as transformer tap changers and generator AVRs may correct the overvoltage – unless this equipment mal-functions. The 7SR24 overvoltage/DTL elements can be used to protect against damage caused by system overvoltages.

If the overvoltage condition is small a relatively long DTL time delay can be used. If the overvoltage is more severe then another element, set at a higher pickup level and with a shorter DTL can be used to isolate the circuit more quickly. Alternatively, elements can be set to provide alarm and tripping stages, with the alarm levels set lower than the tripping stages.

The use of DTL settings allows a grading system to be applied to co-ordinate the network design, the regulating plant design, system plant insulation withstand and with other overvoltage relays elsewhere on the system. The DTL also prevents operation during transient disturbances.

The use of IDMTL protection is not recommended because of the difficulty of choosing settings to ensure correct co-ordination and security of supply.

2.13 Neutral Overvoltage (59N)

Neutral Overvoltage Displacement (Residual Overvoltage) protection is used to detect an earth fault where little or no earth current flows.

This can occur where a feeder has been tripped at its HV side for an earth fault, but the circuit is still energised from the LV side via an unearthed transformer winding. Insufficient earth current would be present to cause a trip, but residual voltage would increase significantly; reaching up to 3-times the normal phase-earth voltage level.

If Neutral Overvoltage protection is used, it must be suitably time graded with other protections in order to prevent unwanted tripping for external system earth faults.

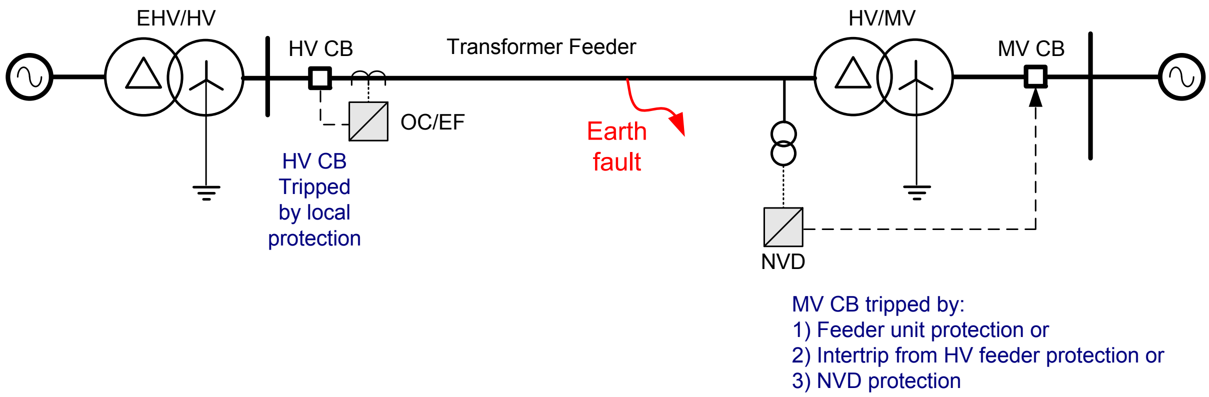


Figure 2.13-1 NVD Application

Typically NVD protection measures the residual voltage ($3V_0$) directly from an open delta VT or from capacitor cones – see fig. 2.13-2 below.

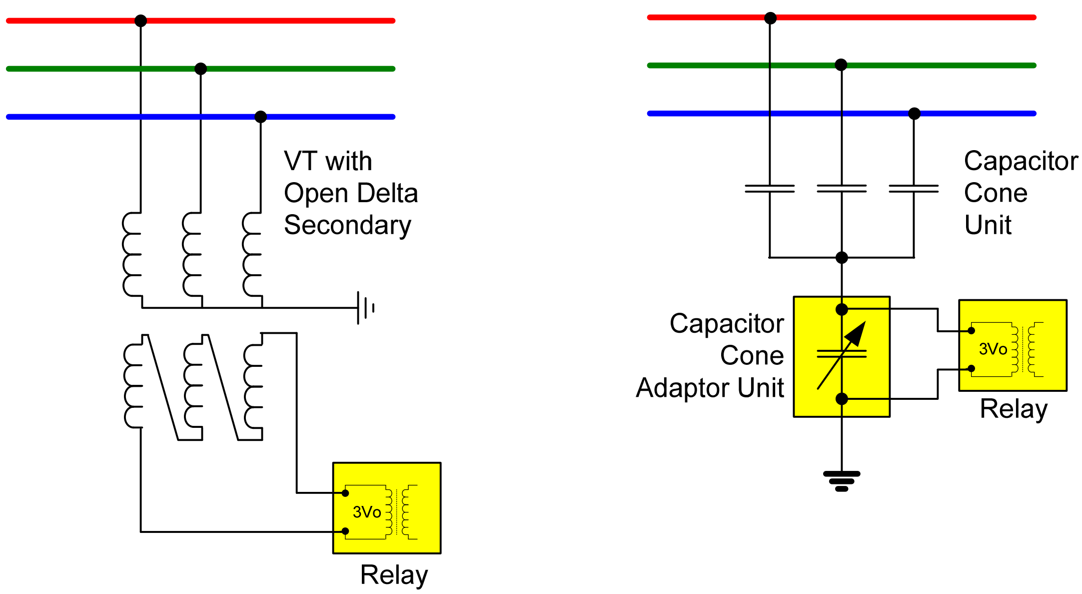


Figure 2.13-2 NVD Protection Connections

2.13.1 Application with Capacitor Cone Units

Capacitor cones provide a cost effective method of deriving residual voltage. The wide range of capacitor cone component values used by different manufacturers means that the relay cannot be connected directly to the cones.

The external adaptor unit contains parallel switched capacitors that enable a wide range of values to be selected using a DIL switch and hence the Capacitor Cone output can be scaled to the standard relay input range.

2.13.2 Derived NVD Voltage

Alternatively NVD voltage can be derived from the three phase to neutral voltages, this setting is available within the relay. Note with this method the NVD protection may mal-operate during a VT Fail condition.

2.14 Negative Phase Sequence Overvoltage (47)

Negative Phase Sequence (NPS) protection detects phase unbalances and is widely used in protecting rotating plant such as motors and generators. However such protection is almost universally based on detecting NPS Current rather than Voltage. This is because the NPS impedance of motors etc. is much less than the Positive Phase Sequence (PPS) impedance and therefore the ratio of NPS to PPS Current is much higher than the equivalent ratio of NPS to PPS Voltage.

NPS Voltage is instead used for monitoring busbar supply quality rather than detecting system faults. The presence of NPS Voltage is due to unbalanced load on a system. Any system voltage abnormality is important since it will affect every motor connected to the source of supply and can result in mass failures in an industrial plant.

The two NPS Voltage DTL elements should therefore be used as Alarms to indicate that the level of NPS has reached abnormal levels. Remedial action can then be taken, such as introducing a Balancer network of capacitors and inductors. Very high levels of NPS Voltage indicate incorrect phase sequence due to an incorrect connection.

2.15 Under/Over Frequency (81)

During normal system operation the frequency will continuously vary over a relatively small range due to the changing generation/load balance. Excessive frequency variation may occur for:

> Loss of generating capacity, or loss of mains supply (underfrequency): If the governors and other regulating equipment cannot respond to correct the balance, a sustained underfrequency condition may lead to a system collapse.
>
> Loss of load – excess generation (overfrequency): The generator speeds will increase causing a proportional frequency rise. This may be unacceptable to industrial loads, for example, where the running speeds of synchronous motors will be affected.

In the situation where the system frequency is falling rapidly it is common practise to disconnect non-essential loads until the generation-load balance can be restored. Usually, automatic load shedding, based on underfrequency is implemented. Underfrequency relays are usually installed on the transformer incomers of distribution or industrial substations as this provides a convenient position from which to monitor the busbar frequency. Loads are disconnected from the busbar (shed) in stages until the frequency stabilises and returns to an acceptable level.

The 7SR24 has six under/over frequency elements.

An example scheme may have the first load shedding stage set just below the nominal frequency, e.g. between 49.0 - 49.5Hz. A time delay element would be associated with this to allow for transient dips in frequency and to provide a time for the system regulating equipment to respond. If the first load shedding stage disconnects sufficient plant the frequency will stabilise and perhaps return to nominal. If, however, this is not sufficient then a second load shedding stage, set at a lower frequency, will shed further loads until the overload is relieved. This process will continue until all stages have operated. In the event of the load shedding being unsuccessful, a final stage of underfrequency protection should be provided to totally isolate all loads before plant is damaged, e.g. due to overfluxing.

An alternative type of load shedding scheme would be to set all underfrequency stages to about the same frequency setting but to have different length time delays set on each stage. If after the first stage is shed the frequency doesn't recover then subsequent stages will shed after longer time delays have elapsed.

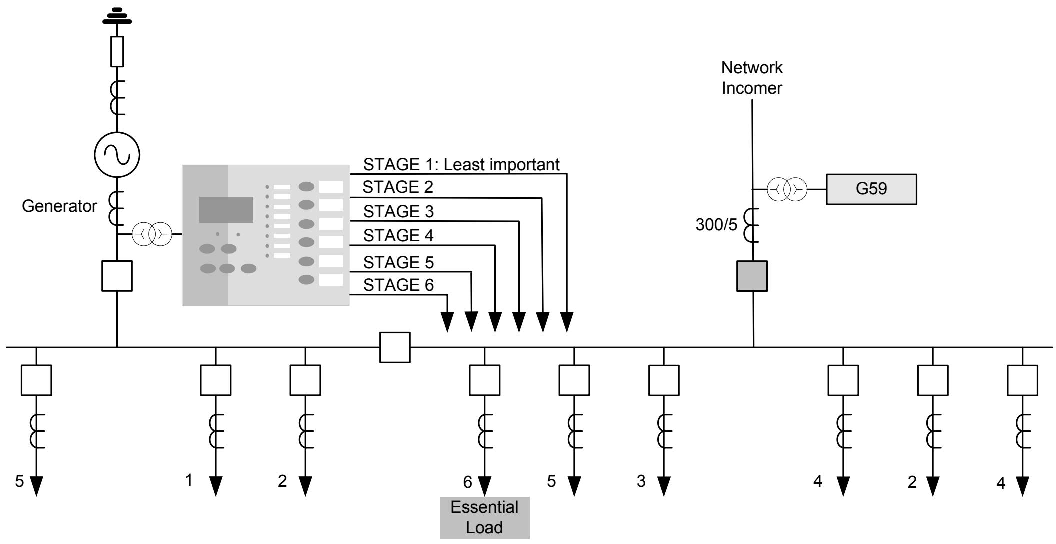


Figure 2.15-1 Load Shedding Scheme Using Under-Frequency Elements

Section 3: CT Requirements

3.1 CT Requirements for Overcurrent and Earth Fault Protection

3.1.1 Overcurrent Protection CTs

a) For industrial systems with relatively low fault current and no onerous grading requirements - a class 10P10 with VA rating to match the load.

b) For utility distribution networks with relatively high fault current and several grading stages - a class 5P20, with VA rating to match the load.

Note: if an accuracy limit factor is chosen which is much lower than the maximum fault current it will be necessary to consider any effect on the protection system performance and accuracy e.g. grading margins.

For i.d.m.t.l. applications, because the operating time at high fault current is a definite minimum value, partial saturation of the CT at values beyond the overcurrent factor has only a minimal effect. However, this must be taken into account in establishing the appropriate setting to ensure proper grading.

Definite Time and Instantaneous Overcurrent

a) For industrial systems with requirements as for i.d.m.t.l. relays item (a) above, a class 10P10 (or 20).

b) For utilities as for (b) above - a class 5P10 (or 20), with rated burden to suit the load.

Note: Overcurrent factors do not need to be high for definite time protection because once the setting is exceeded magnitude accuracy is not important. Often, however, there is also the need to consider instantaneous HighSet overcurrent protection as part of the same protection system and the settings would normally be of the order of 10x the CT rating or higher. Where higher settings are to be used then the overcurrent factor must be raised accordingly, e.g. to P20.

3.1.2 Earth Fault Protection CTs

Considerations and requirements for earth fault protection are the same as for Phase fault. Usually the relay employs the same CT's e.g. three phase CTs star connected to derive the residual earth fault current.

The accuracy class and overcurrent accuracy limit factors are therefore already determined and for both these factors the earth fault protection requirements are normally less onerous than for overcurrent.

3.2 CT Requirements for High Impedance Restricted Earth Fault Protection

For high impedance schemes it is necessary to establish characteristics of the CT in accordance with Class ‘PX’ to IEC 60044. The basic requirements are:

All CT’s should, if possible have identical turns ratios.

The knee point voltage of each CT, should be at least 2 x Vs.

The knee point voltage is expressed as the voltage applied to the secondary circuit with the primary open circuit which when increased by 10% causes the magnetizing current to increase by 50%.

Where the REF function is used then this dictates that the other protection functions are also used with class PX CTs.

Section 4: Control Functions

4.1 Auto-reclose Applications

Automatic circuit reclosing is extensively applied to overhead line circuits where a high percentage of faults that occur are of a transient nature. By automatically reclosing the circuit-breaker the feature attempts to minimise the loss of supply to the customer and reduce the need for manual intervention.

The Recloser supports up to 4 ARC sequences. That is, 4 x Trip / Recloses followed by a Trip & Lockout. A lockout condition prevents any further attempts, automatic or manual, to close the circuit-breaker. The number of sequences selected depends upon the type of faults expected. If there are a sufficient percentage of semi-permanent faults which could be burnt away, e.g. fallen branches, a multi shot scheme would be appropriate. Alternatively, if there is a high likelihood of permanent faults, a single shot scheme would minimise the chances of causing damage by reclosing onto a fault. In general, 80% of faults will be cleared by a single Trip and Reclose sequence. A further 10% will be cleared by a second Trip and Reclose. Different sequences can be selected for different fault types (Phase/Earth/Sensitive Earth faults).

The Deadtime is the interval between the trip and the CB close pulse being issued. This is to allow for the line to go ‘dead’ after the fault is cleared. The delay chosen is a compromise between the need to return the line to service as soon as possible and prevented unnecessary trips through re-closing too soon. The Reclaim Time is the delay following a re-closure before the line can be considered back in service. This should be set long enough to allow for protection operation for the same fault, but not so long that two separate faults could occur in the same Autoreclose (ARC) sequence and cause unnecessary lockouts.

The Sequence Fail Timer provides an overall maximum time limit on the ARC operation. It should therefore be longer than all the set delays in a complete cycle of ARC sequences; trip delays, Deadtimes, Reclaim Time etc. Generally this will only be exceeded if the circuit-breaker has either failed to open or close.

Since large fault currents could potentially damage the system during a prolonged ARC sequence, there are also settings to identify which protection elements are High-sets and these can cause an early termination of the sequence.

Where a relay is to operate as part of an ARC scheme involving a number of other relays, the feature attempts to clear any faults quickly without regard to normal fault current grading. It does this by setting each Trip element to be either Delayed or Instantaneous. Instantaneous Trips are set to operate at just above maximum load current with small delays while Delayed Trips are set to suit actual fault levels and with delays suitable for current grading.

A typical sequence would be 2 Instantaneous Trips followed by a Delayed Trip & Lockout:

- When any fault occurs, the relay will trip instantaneously and then reclose.
- If this does not clear the fault, the relay will do the same again.
- If this still does not clear the fault, the fault is presumed to be permanent and the next Trip will be Delayed and so suitable for grading with the rest of the network. Thus allowing downstream protection time to operate.
- This Trip will Lockout the ARC sequence and prevent further recloses.

It is important that all the relays in an ARC scheme shadow this process – advancing through their own ARC sequences when a fault is detected by an element pickup even though they are not actually causing a trip or reclose. This is termed Sequence Co-ordination and prevents an excessive number of recloses as each successive relay attempts to clear the fault in isolation. For this reason each relay in an ARC scheme must be set with identical Instantaneous and Delayed sequence of trips.

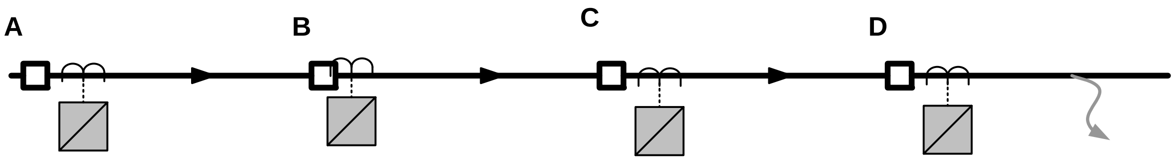


Figure 4.1-1 Sequence Co-ordination

The relay closest to the fault (D) would step through its Instantaneous Trips in an attempt to clear the fault. If unsuccessful, the relay would move to a Delayed Trip sequence.

The other relays in the network (A, B and C) would recognise the sequence of Pick-up followed by current switch-off as ARC sequences. They would therefore also step to their Delayed Trip to retain co-ordination with the respective downstream devices.

The next Trip would be subject to current grading and Lockout the ARC sequence such that the fault is cleared by the correct CB.

4.1.1 Auto-Reclose Example 1

Requirement: Settings shall provide four phase fault recloses – two instantaneous and two delayed - and only two recloses for faults detected by the SEF protection.

Proposed settings include:

CONTROL & LOGIC > AUTORECLOSE PROT'N:

***79 P/F Inst Trips*: 50-1**

***79 P/F Delayed Trips*: 51-1**

***79 SEF Delayed Trips*: 51SEF-1**

CONTROL & LOGIC > AUTORECLOSE CONFIG

***79 Num Shots*: 4**

CONTROL & LOGIC > AUTORECLOSE CONFIG > P/F SHOTS

***79 P/F Prot'n Trip 1* : Inst**

***79 P/F Prot'n Trip 2* : Inst**

***79 P/F Prot'n Trip 3* : Delayed**

***79 P/F Prot'n Trip 4* : Delayed**

***79 P/F Delayed Trips to Lockout* : 3**

CONTROL & LOGIC > AUTORECLOSE CONFIG > SEF SHOTS

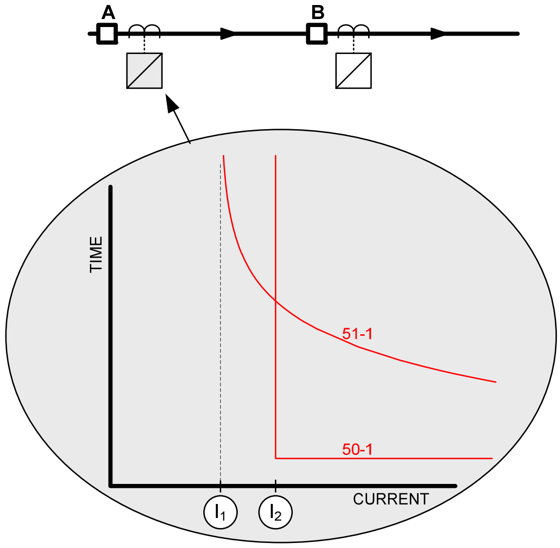
***79 SEF Prot'n Trip 1* : Delayed**

***79 SEF Prot'n Trip 2* : Delayed**

***79 SEF Delayed Trips to Lockout* : 3**

Note that Instantaneous' shots are inhibited if the shot is defined as 'Delayed'

4.1.2 Auto-Reclose Example 2 (Use of Quicklogic with AR)



Requirement: The relay at location ‘A’ it is required to provide a reclose sequence of 2 Instantaneous followed by 2 delayed recloses. Where the fault current level is between the values ‘I1’ and ‘I2’ and the first trip is initiated from the 51-1 (IDMT) element, the IDMT characteristic should trip the CB and lockout the auto-reclose.

Typical settings are:

CONTROL & LOGIC > AUTORECLOSE PROT’N:

***79 P/F Inst Trips*: 50-1**

***79 P/F Delayed Trips*: 51-1**

CONTROL & LOGIC > AUTORECLOSE CONFIG > P/F SHOTS

***79 P/F Prot’n Trip 1* : Inst**

***79 P/F Prot’n Trip 2* : Inst**

***79 P/F Prot’n Trip 3* : Delayed**

***79 P/F Prot’n Trip 4* : Delayed**

The above settings are suitable at values of fault current above ‘I2’ however were a fault to occur with a current value between ‘I1’ and ‘I2’ this would be detected by the 51-1 element only. As ***Prot’n Trip 1*** = **Inst** then the relay would trip and reclose whereas it is required to lockout for this occurrence.

To provide a lockout for the above faults an additional element 50-2 with identical settings to 50-1 is assigned as a Delayed Trip and is used in conjunction with the Quick Logic feature i.e.

OUTPUT CONFIG>OUTPUT MATRIX: ***51-1*** = **V1**

OUTPUT CONFIG>OUTPUT MATRIX: ***50-2*** = **V2**

OUTPUT CONFIG>OUTPUT MATRIX: ***E1*** = **V3**

CONTROL & LOGIC>QUICK LOGIC: ***E1*** = **V1.!V2**

INPUT CONFIG>INPUT MATRIX: ***79 Lockout*** = **V3**

4.2 Synchronising

The 7SR224 includes an optional Synchronising function which can be incorporated into the autoreclose and manual close sequences. The device provides a combined check and system synchronising function which can automatically select check or system synchronise, as appropriate, from measurements of the relative phase angles between the line and bus voltages. The relay will prevent closure of the circuit breaker if the phase angle, slip frequency or the voltage magnitudes of the incoming and running voltages fall outside prescribed limits. Both the check and system synchronise functions have independent settings and blocking features. Synchronising bypass logic is provided to close or block close when the circuit breaker is dead on the line side, bus side or both.

4.2.1 Check Sync, System Sync

The function can be used as a check and system synchronising relay for applications where two power systems are to be connected. The following examples show various ways that the relay can be enabled for different applications.

The device will switch between check sync (CS) and system sync (SS) modes to suit system conditions. If the requirement is for the relay to be used as a check before closing or reclosing a normal distribution network, then system sync consideration is not required:

Set MC Split Mode to CS

Set DAR Split Mode to CS

This specifies that when a system split is detected during a MC or DAR operation, the CS mode will be retained and the split detection ignored.

If the possibility of a system split is applicable but the network should not be reclosed by DAR in these circumstances then:

Set DAR Split Mode to LO (Lockout)

If the independent System Sync settings are to be used following a Split detection during DAR, then:

Set DAR Split Mode to SS

The reaction to a split detection during a Manual Close operation can be specified separately:

Set MC Split Mode to SS

Similarly, the device can be set to use Close On Zero (COZ) for either or both modes following a split detection.

4.2.2 Rated Voltage Setting – V.T. Connection

The Vx analogue voltage input is used for the synchronising Bus voltage and can be either Van, Vbn, Vcn, Vab, Vbc or Vca. The voltage is compared to the respective Line voltage connected to the V1-V3 analogue voltage inputs.

V.T. ratings for secondary connections are normally either 100V or 110V for phase-phase, with the associated phase-neutral ratings being 57.7V and 63.5V respectively. For phase-neutral connections the Vx Nom Voltage setting in the CT/VT Config menu should be set to 63.5V. For phase-phase connections the Rated Voltage setting should be set to 110V etc. Voltage element settings are a percentage of this setting..

4.2.3 Bus/Line Undervolts Settings

The relay undervoltage blocking elements, if enabled, can be used to block the close operation if either the line (incoming) or bus (running) voltages fall below a certain percentage of rated voltage. Typically, the undervoltage elements are set between 80% and 90% of rating.

Note : when using the undervoltage elements care should be taken to ensure that the reset of the element occurs at below the expected minimum normal operating voltage of the system. The undervoltage elements reset at <103% of the operate level. If the system is expected to run at less than the rated voltage, the undervoltage element reset level must be set to operate at a value below this plus a discrimination margin.

e.g. - for a phase to neutral connection nominally at 63.5 Vrms but which can run as low as 59 Vrms,

the undervoltage setting should be set no higher than 59 V – 1 V (margin) = 58V / 103% = 56.31V (the actual setting would have to be 56.5V). This is equivalent to approximately 89% of rated voltage. If the setting is set higher than this then the element may never reset and will continuously block.

4.2.4 Voltage Differential Settings

A differential voltage detector is incorporated and this, if enabled, blocks the synchronising function if the difference between the measured bus and line voltages is greater than the setting. This is used to prevent closing of the circuit breaker with a large voltage differential between the line (incoming) or bus (running) voltages, which could overstress the electrical systems. Typically, the differential voltage elements are set below 10% of rated voltage.

4.2.5 Synchronising Bypass Logic

The relay Dead and Live voltage monitors are used along with corresponding internal logic to bypass the synchronising operation of the relay. Typically, anywhere above 80% to 90% of rating can be classed as a live line or live bus. The dead voltage monitors should be set to somewhere above the expected level of induced voltages on the line or bus. It should be noted that a dead line or dead bus can have a considerable potential induced onto it from a parallel line or via capacitance across open breaker contacts. This potential on some networks can be as high as 30% of rated voltage.

The synchronising Bypass logic can be enabled, if required, to provide the following:

- Line charging and/or Bus charging, from the other side which is live.
- Close with both sides dead,
- Synchronising check with both sides live.
- Unconditional Close (ignore all voltage conditions)

Different options can be enabled for Manual Closing and DAR operations. This can be used for example to allow MC operations to be carried out with both sides dead for normal operational switching but prevent closing if the condition occurred during DAR. Alternatively, the device at one line end can be set to provide line charging whilst the other only Check Sync, i.e. after the line has been restored and become live.
Additional DLC and DBC delays are provided to allow co-ordination of devices whilst also allowing a close applied conditions after a delay if the normally expected conditions are not met. For example, a device which will usually be the second end to close, thus operating in Check Sync mode, can allow Dead Line Close after a further delay, thus charging the line if the first end fails to close.

4.2.6 Slip and Phase Angle Relationship

Slip frequency is defined as the difference between two frequencies. Where a slip frequency exists between two separate systems, during a ‘slip’ cycle the two voltage vectors will be in anti-phase at one point in time. The phase angle difference will vary between being in phase and anti-phase. The relay can be set to measure slip frequency in two ways. One way is to measure the two system frequencies directly and calculate the difference. Another way is to measure the phase difference between the two systems and check that the phase angle change in a defined time period is less than a predetermined value. If F1 and F2 represent the frequencies of two systems then it can be shown that for check synchronising operation,

$$\Delta \mathrm{F} = \mathrm{F1} - \mathrm{F2} = \frac{1}{\mathrm{Td}} \times \frac{\theta}{180°}$$

where Td = time delay setting and θ = phase angle setting.

For system synchronising operation the following formula is used because in this mode the relay will only issue a close signal if the phase angle is decreasing in value. It will not issue a close if the phase angle is increasing in value.

$$\Delta \mathrm{F} = \mathrm{F1} - \mathrm{F2} = \frac{1}{\mathrm{Td}} \times \frac{\theta}{360°}$$

where Td = time delay setting and θ = phase angle setting.

The relay has both a frequency measuring element and phase detector and so can be set up to measure slip either directly or by the phase detector plus timer method. Use of either method is perfectly valid, as is use of both at the same time.

Note : if using both the slip frequency detector and the phase angle plus slip timer for a particular scheme then care has to be taken in setting selection. It is possible to set the relay up with an incorrect slip timer setting which will prevent the relay from issuing a valid close signal.

e.g. - a system with a high rate of slip which is within the allowable slip frequency limit, could be set up with too long a slip timer setting. This would mean that the incoming vector could pass through the valid close window too quickly and not allow the slip timer to time out and give a valid output.

4.2.7 Check Synchronising Settings

The check synchronising operation of the relay is used mainly in switching operations which link two parts of a system which are weakly tied via other paths elsewhere in the system. In this synchronous system there should be no frequency difference across the breaker but significant differences in phase angle and voltage magnitude may exist due to the transmission line characteristics such as its length and type of loading.

For check synchronising operation the relay should be set to the maximum phase angle and maximum voltage differences which still permit the circuit breaker to close without causing large disturbances to the system. For most systems the phase angle can be set between 20° and 30°. There should not be any slip frequency but a setting of 50mHz is typically applied as a check against loss of synchronism due to tripping of all parallel interconnections. Table 2 shows some possible check synchronising settings when using the phase detector plus time delay method. This shows a range of phase angles and the required slip timer settings to achieve a slip frequency limit of 50mHz. Note that due to the step resolution of the timer, an exact 50mHz slip limit is not always achievable.

CS Phase Angle Setting (□°)	CS Slip Timer Setting (sec)	Slip Frequency Limit (mHz)
± 10°	1.1	50.51
± 15°	1.7	49.02
± 20°	2.2	50.51
± 25°	2.8	49.60
± 30°	3.3	50.51
± 35°	3.9	49.86
± 40°	4.4	50.51
± 45°	5.0	50.00

Table 4-1 Typical Check Synchronising Settings

Alternatively, if the slip frequency detector is used and the slip timer turned OFF, a setting of 50mHz could be applied to the slip frequency detector directly to achieve the same ends.

Note : in check synchronising mode the valid phase difference window for closing is actually twice the phase angle setting value because the valid Check Sync close can be given when the phase angle is either decreasing or increasing.

4.2.8 System Synchronising Settings

The changeover to system synchronising operation will occur automatically if set, if the two systems become asynchronous i.e. there are no ties between the two systems and one system is effectively ‘islanded’. If this situation occurs the frequencies will slip past each other and may cause the phase angle to come into the system split limits. The system split detector can be set to operate on a differential angle anywhere from 90° to 175° and is typically set to 170°. Alternatively, the change to System Sync can be made based on Slip frequency using a high value of typically 125mHz or more.

When there are high rates of slip between the two systems greater care is needed when closing the breaker and for this reason the system synchronising mode has independent settings from the check synchronising mode. The allowable phase angle close window is usually set much narrower than for check synchronising operation. Also, the close decision from the relay is only given in the case of the phase angle decreasing. It will not issue a close if the phase angle is increasing in value. Typically the slip frequency will be set to a limit of 250mHz or less and the phase angle to 10° or 15°. Table 4-2 shows some possible system synchronising settings for limits of 100mHz and 250mHz. Note that due to the step resolution of the timer, an exact 100mHz or 250mHz slip limit is not always achievable.

SS Phase Angle Setting (□°	SS Slip Timer Setting (sec)	Slip Frequency Limit (mHz)
± 10°	0.3	92.59
± 15°	0.4	104.17
± 10°	0.1	277.78

± 15°	0.2	208.33

Table 4-2 Typical System Synchronising Settings

Alternatively, if the slip frequency detector is used and the slip timer turned OFF, settings of 100mHz or 250mHz could be applied to the slip frequency detector directly to achieve the same ends.

The relay will automatically revert to Check Synchronising mode when zero slip is applied.

4.2.9 Example Setting Calculations For Slip Timer

In Check Synchronising operation the relay will issue a Check Sync close if the system conditions are such that the phase angle and slip frequency are within limits. There is a possibility, however, that a Check Sync close could be issued at a point where the phase angle is approaching the angular limits, say + 20°, and the slip frequency is at the maximum allowable value. The consequence of this is that due to the inherent closing time of the CB the actual CB close occurs outside of the phase angle limits. The angle overshoot being dependent on the actual slip frequency and the total CB closing delay.

The total delays involved in this process include the main software timing loop which issues the close command, the output relay time to pick up and the actual breaker closing time delays. To reduce the risk of a late closure it is common practice to set the slip timer setting (Td) to typically 10x the CB closing time. This will ensure that the CB will close no later than 1.2x the actual phase angle setting of the relay e.g. ± 24° for a ± 20° setting.

e.g. :-

The change in phase angle between two waveforms is directly related to the frequency difference, or slip, between them. The change in phase angle $\Delta\theta$ for a system with 1Hz slip is 360º in 1 second. Thus,

Change in phase angle $\Delta\theta = (\text{Slip} \times 360)$ °/sec.

The distance the phasor can travel during the breaker close time can therefore be given by,

$\Delta\theta = (\text{Slip} \times 360 \times t_{CB})$ - where t_{CB} is the breaker close time in seconds.

Using the equation given in section 2.7 for check synchronising,

$\text{Slip} = \frac{1}{\text{Td}} \times \frac{\theta}{180^\circ}$ and substituting this into $\Delta\theta = (\text{Slip} \times 360 \times t_{CB})$ gives the following,

$\Delta\theta = \frac{1}{\text{Td}} \times \frac{\theta}{180^\circ} \times 360^\circ \times t_{CB}$ which gives $\Delta\theta = 2 \times \theta \times \frac{t_{CB}}{\text{Td}}$

It was stated that the slip timer setting Td should be set to 10x the breaker closing time t_{CB}.

Substituting for this in the above equation gives,

$\Delta\theta = \frac{(2 \times \theta)}{10}$ or $\Delta\theta = 0.2 \times \theta$

Thus for a slip timer setting (Td) of 10x breaker closing time (t_{CB}) the actual change in phase angle will be 20% of the phase angle setting. The maximum closing angle will be 120% of phase angle setting.

In practice, however, the relay operating times need to be taken into consideration. A typical example now follows :

- Maximum allowed phase angle for closure = 30°.

- Circuit breaker closure time = 150ms.

Maximum relay delays : Software timing loop + Output relay delays = 5ms + 7ms = 12ms.

Therefore slip timer time delay should be set to 10x (150ms + 12ms) = 1.62sec. In practice this will have to be set to 1.6sec due to the resolution of the slip timer.

The phase angle setting should be set to 80% of the maximum allowable closing angle, which is 24°.

If the relay was to issue a close right on the boundary of 24□ then the breaker will not close outside of 30°.

With an angle of 24° and a slip timer delay (Td) of 1.6sec, using the equation from section 2.7, the slip is therefore, 24 / (1.6 x 180) = 83mHz. If the relay were to close on the boundary the phase angle traversed in the 160ms total delay time is given by,

$\Delta\theta = (\text{Slip} \times 360) \times (t_{CB} + t_{RELAY})$ = 0.083 x 360 x 0.16 = 4.80°.

Therefore the CB will close at 24° + 4.80° = 28.80°.

4.2.10 Close on Zero

Close on zero is the preferred method of some customers for restoration of a split system. The relay uses the measured slip frequency and the typical closing time of the circuit breaker to issue a close pulse, as the phase difference is reducing, which will close the circuit breaker when the phase difference is zero. High accuracy is not required regarding the *CB Close Time*.

4.3 Loss of Voltage (LOV) Loop Automation Function

This additional functionality is available as an ordering option when required to suit application requirements. The LOV Automation function is applied by Reclosers at the sectioning points along a feeder and by a Normally Open Point (NOP) at the junction of two feeders, see

, the purpose is to ensure the automatic restoration of system supply to as many customers as is possible following the lockout of a source Recloser and de-energisation of a feeder due to a permanent fault. The resultant permanent loss of supply to healthy sections of the faulted feeder can be avoided by the sequential closure of the NOP (TIE) Recloser and multiple Line Reclosers to back feed supply and isolate the faulted section. This sequence can be triggered by Loss Of Voltage to automatically and relatively quickly, restore the power to healthy sections and thus limit the disruption to Customers and minimising the Customer Minutes Lost (CML) metric. LOV Automation should be considered as a one shot automated sequence after which, the normal NOP having been closed, manual operations should be taken to clear the fault and restore the system to its normal configuration. The LOV Function described does however have the capability of reconfiguration after other permanent fault(s) occurring, after the first-fault LOV automation sequence, depending on their location within the system. However, if no manual action is to be taken the increase of load level on the back-feed feeder(s) must be considered.

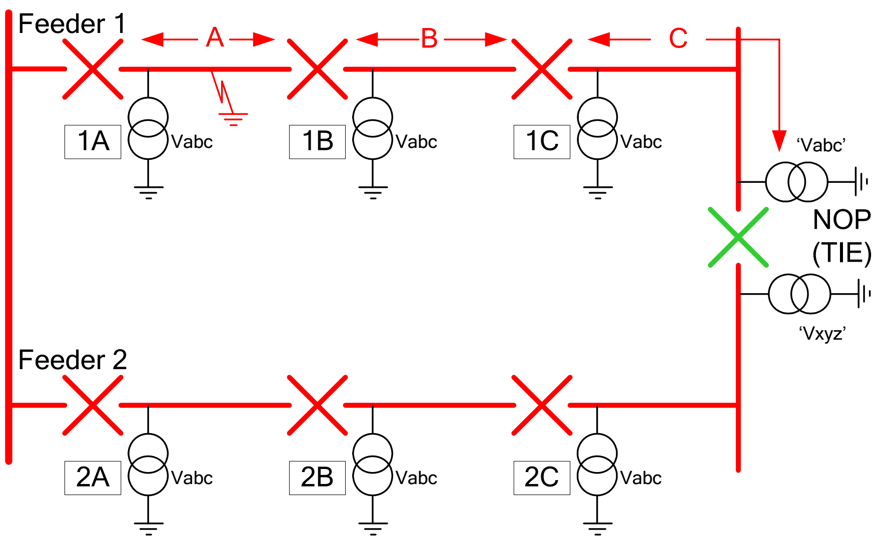


Figure 4.3-1 Sysyem Diagram showing Normally Open (TIE) Point

Reclosers in the network must be designated as one of 3 different types:

Recloser: If a LOV condition is diagnosed when the recloser is in the closed state, the controller issues a trip then subsequently recloses on restoration of voltage as part of an automated sequence to provide sectioning points along the feeder.

NOP (Tie): This device operates as a normally open point in the network which is closed automatically as part of the sequence to provide a backfeed from a different, unfaulted feeder when voltage is detected as lost.

Feeder: The controller issues a trip on detection of LOV, followed by no further action to establish a new normally open point in the network arrangement which results from the automated sequence.

The starting point is that on a normal healthy system all Reclosers A, B & C on both Feeders will be closed as shown in

and the NOP will be open. All Devices will have the same voltage on their upstream and downstream sides and voltage will be present on both sides of the NOP (TIE) point. It should be noted that Reclosers at different points in the system are programmed to give the optimum, different, reaction to Loss Of Voltage and that their response is not conditional on seeing fault current, only on detection of loss of voltage. An LOV sequence starts to operate due to prolonged absence of voltage which occurs when a CB or Recloser goes to Lockout after a persistent fault is isolated from the supply i.e. fault current no longer flows, following a complete but unsuccessful autoreclose sequence. The actual cause of the fault still remains but is isolated on its normal source side from the supply and from adjacent feeders by the NOP.

For a fault at the position shown on the Feeder 1- A section, the 1A CB/Source Recloser will go through a sequence of Fast plus Delayed trips to attempt to clear the fault. For a permanent fault the outcome will be that 1A goes to Lockout and Feeder 1 will be left totally dead. Feeder 1 does however have healthy sections e.g. 1B to 1C and 1C to the NOP which can be given back-feed supply from Feeder 2 if a structured restoration cycle is initiated by the automatic closure of the NOP. This is achieved as follows;- following the Lockout of the Source Recloser/CB-1A, the Line Reclosers 1B and 1C will both see permanent Loss Of voltage (LOV), (this may also have occurred temporarily, more than once during or for the whole, of the 1A recloser sequence).

1B and 1C can be set as type *Recloser* in the *LOV Automation* menu. In this case if *LOV Recloser Opening* in each is set to Enabled and they see permanent LOV on both sides for more than a user set LOV Action Delay e.g. 60 seconds, set by the user to cover a complete upstream sequence, then their LOV Elements will each take action and give a 3 pole Trip output, both 1B and 1C will therefore Trip and Lockout at about the same time.

The NOP, which is set as type *NOP (Tie)* in the *LOV Automation* menu, in example 1, will see LOV on its Feeder 1 side and will have normal system voltage available on its Feeder 2 side; if the NOP's LOV Element sees permanent LOV on either side i.e. lasting for more than a user set LOV Action Delay e.g. 75 seconds to give a grading margin to allow time for Reclosers 1A and 1B to open at, for example, 60 seconds, then the NOP LOV Element will take action and issue a NOP Close.

A type *NOP (Tie)* has separate settings for *LOV-A Action Delay* and *LOV-X Action Delay* to allow different delays to be applied for Loss of voltage action on either side of the Recloser.

For this NOP Close action the NOP Protection must be primed to perform one Fast Protection Line Check Trip & Lockout, thus, if the NOP closes onto a permanent fault or a fault appears during a set *LOV SOTF Time* (e.g. 5 seconds), on section 1C then the NOP will perform a Fast Protection Trip & Lockout. If the NOP close is successful and no fault appears, the C section of Feeder 1 will thus be back-fed. The NOP Line Check mode must be maintained as Fast Protection during its *LOV SOTF Time* but must then be changed to Delayed for the Recloser's *LOV Reclaim Time*.

Recloser 1C will now see voltage on its downstream side and if that voltage is present for the user set LOV SOTF Time e.g. 5 seconds, then 1C's LOV Element in turn will then issue a Reclose and 1C will close. Note that the 1C Protection will be primed to perform one Fast Protection Line Check Trip & Lockout, thus, if 1C closes onto a permanent fault, or a fault appears during its set *LOV SOTF Time* e.g. 5 seconds, then 1C will Fast Protection Trip and Lockout. If the Recloser close is successful the B section of Feeder 1 will thus be back-fed. The 1C Line Check mode must be maintained as Fast Protection during its *LOV SOTF Time* but must then be changed to Delayed for the Recloser's *LOV Reclaim Time*.

Recloser 1B will now see voltage on its downstream side and if that voltage is present for the user set *LOV SOTF Time* e.g. 5 seconds, then 1B's LOV Element in turn will then issue a Reclose and 1B will close. Note the 1B Protection will be primed to perform one Fast Protection Line Check Trip & Lockout thus if 1B closes onto a permanent fault, or a fault appears during its set *LOV SOTF Time* e.g. 5 seconds, then 1B will Fast Protection Trip & Lockout. If the Recloser close is successful then the A section of Feeder 1 will thus be back-fed. The 1B Line Check mode must be maintained as Fast Protection during its LOV Reclose reclaim Delay but must then be changed to Delayed for the Recloser's *LOV Reclaim Time*.

For the example shown 1B will be reclosed onto a permanent fault and will therefore perform its Fast Line Check Trip & Lockout with 1C now applying only Delayed protection. This will leave the healthy 1B and 1C sections backfed via the NOP.

As can be seen from the above, the NOP and each Recloser will close sequentially at the User set (e.g. 5 seconds) intervals and each Recloser when it Closes will be primed to perform a single Fast Protection Line Check Trip & Lockout for its Close whilst all other Reclosers/NOP have had their protection changed from Fast Protection Line Check Trip & Lockout to a Delayed Line Check Trip & Lockout; this ensures that the Recloser closing onto a faulted section will trip Fast Protection and clear the fault leaving all the other proven, unfaulted, sections energised. This mode of operation does impose a fault, which will be cleared by a single high-speed Fast-Protection Trip, onto an otherwise healthy system but it does result in 'as much of the System being maintained in-service as possible'.

If, following a Loss of Voltage and LOV Automation initiation, a type *Recloser* does not see Voltage re-appear on one side to allow the LOV Automation process to proceed, then on expiry of the *LOV Sequence Time* i.e. the LOV Automation time-allowed-to-live timer, the LOV Sequence will be terminated and the Recloser will go to Lockout.

The NOP and the Reclosers involved in the restoration sequence must have their *LOV Reclaim Time* settings set to a longer time, with grading margin > 5 secs, than the maximum time taken for the last Recloser X in the LOV Sequence to complete its LOV sequence and Reclose, tripping to clear any permanent fault which presents itself as necessary. This is necessary to ensure that the NOP and all Reclosers, which will see fault current when the last Recloser in the sequence closes, remain programmed to perform a Delayed Trip without reclose until after all Reclosers have completed their part in the Automation sequence and the system is restored unfaulted.

Once the NOP and feeder Reclosers have completed their LOV sequences and have LOV Reclaimed then they must now have co-ordinated grading to be able to deal correctly with a second fault on one of the healthy sections. This co-ordinated grading, under back-feed conditions following NOP(TIE) closure, is achieved by programming all the Reclosers in the LOV back-feed loops to be bi-directional, their settings in both directions can be co-ordinated by a Grading Study to ensure correct grading for faults fed from either the normal Forward or NOP(TIE) Closed back-feed, Reverse directions.

LOV Element has two main outputs i.e. three pole LOV Trip and three pole LOV Close these can be mapped to the existing CB Open and 79 AR Close outputs, it is not necessary to create new outputs in the output matrix, all other outputs are intended for alarm/indication purposes.

It should be noted that in a typical interconnected system at each feeder end there could be up to 3 NOP (TIE) at that node anyone of which could be closed to back feed supply to that feeder, therefore, there must be a user-set pecking order. The NOP LOV Action Delay timer User settings with grading margins e.g. 75 s - 80 s - 85 s, ensures that the optimum reconfiguration of the system occurs but with redundancy built-in to ensure that supply is restored via a third path should the first or second, choice path not be available or fails, see **Error! Reference source not found.** .

Loss of Voltage at the NOP on $V_A/V_B/V_C$ selects the LOVa Action Delay timer setting; Loss of voltage on $V_X/V_Y/V_Z$ selects the LOVx Action Delay timer setting. As can be seen the result is that each Feeder can have a preferential first choice, a second choice and third choice back-feed feeder, the user can set these independently to suit his system. NOP (TIE) to Feeders from other Sub/Stations will typically always be set to third choice e.g. 85 second Action Delay time. NB the NOP LOV Automation Action Delay on either side can be set to OFF which means that the User can select NOP LOV Close so as to supply power in a single first required direction only, not a second.

The bubbles show examples of the flexibility of the grading arrangement at the node on the end of each feeder, showing how the user can select the 1st, 2nd and 3rd choice back-feed feeders for each feeder. Other arrangements can be set-up by User. Note the NOP (TIE) feeders between Sub/Stations end up with the same Action Delay time settings on both sides.

The LOV Automation function can be Enabled or Disabled, by the User setting and can be switched In/Out dynamically via any Binary Inputs, LOV can also be switched In/Out by Function Key or SCADA General Commands. LOV is automatically inhibited by Voltage Transformer Supervision if a VTS failure is detected.

For a controller with *LOV Plant Device Type* set as *Recloser* to perform its LOV Automation sequence, only the downstream voltage needs to be monitored and therefore addition primary voltage transformers are not required. Reclosers should be mounted and connected so that the standard Voltage measuring devices are on the downstream side as this voltage is monitored for voltage recovery to prompt reclosure. The controller monitors will respond to voltage restoration on either side of the recloser and therefore connections can be made to the 'A' or 'X' side.

For a NOP (TIE) to perform its LOV Automation sequence, the voltage levels on both sides of the NOP i.e. both downstream and upstream voltages, must be monitored. Voltage levels must be continuously monitored as pre-LOV memory of condition states is necessary.

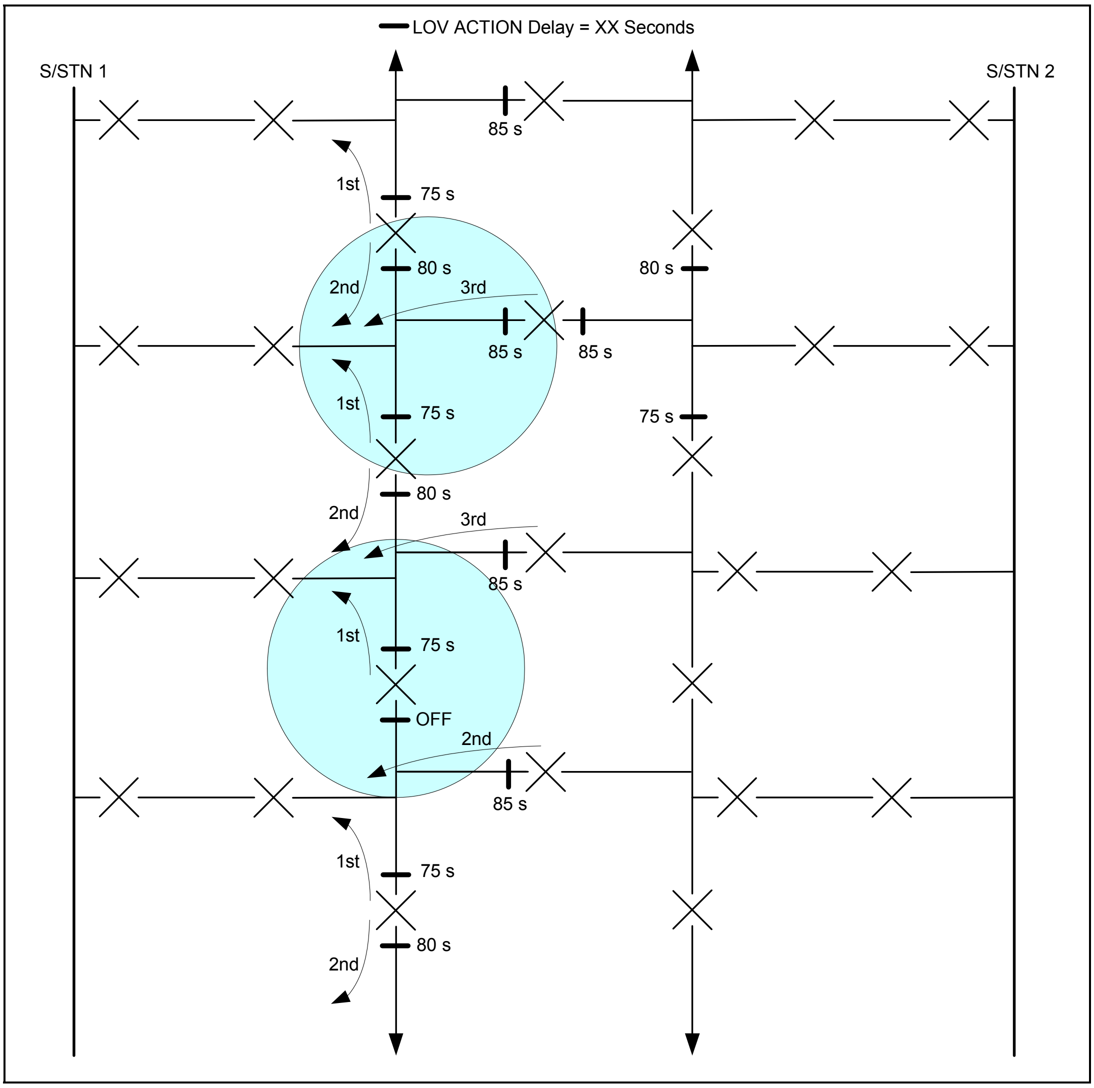


Figure 4.3-2 Typical System Interconnections showing Normally Open (TIE) Points and LOV Action Delay timer grading margins.

An LOV close is blocked by the Block Reclose input in the same way as any autoreclose close. The setting of the Block Reclose Delay should be considered in the setting of the LOV timing.

The LOV function is set to ‘Out’ by default and must be switched ‘In’. The voltages and open/closed state of the recloser is checked when an attempt is made to switch the function ‘In’. A type Feeder or Recloser must be Closed with voltage present on at least 1 side. A type NOP(Tie) must be Open with Live voltage on both sides. This condition must be retained for the *LOV Primed Time* before the ‘primed’ staus is achieved. The device must be in the ‘primed’ state for loss of voltage to start any *LOV Action.* The enable/disable setting *LOV Primed Interlock* can be used to disable the voltage check but the relevant open/closed state is still required. The NOP(Tie) device includes a *LOV Memory Time* which provides a reset delay for the primed condition when voltage conditions of dead both sides is applied. This allows for the fact that during a fault the voltage on the unfaulted side may be depressed by the proximity of the fault.

The devices can be set to start the LOV sequence from loss of voltage on either all three phases or loss of voltage on any single phase. The single phase option can be used to restore load on a system where single pole tripping is permitted.

The LOV system can be set to operate as a single or multi-shot sequence. When selected as Single mode, the LOV Automation function will be automatically switched Out following a successful or unsuccessful LOV sequence and the LOV In signal must be raised by the operator before a further sequence will be executed following a subsequent loss of voltage.

4.4 Single/Triple Autoreclose

4.4.1 System Arrangement for Application of Single/Triple AutoReclose

In countries, such as the USA, where the distribution network is 4 wire i.e. three phase plus neutral, a three phase feeder may run out from a sub/station and then at some point be split into three separate single phase plus neutral feeders where, for example, each line can go up a separate valley and thus be subjected separately to lightning strikes or single phase to Earth (Ground) or Neutral, Faults. Loads can thus be entirely single pole or a mix of three pole and single pole.

Some utilities are upgrading their systems to improve the quality of supply to customers by installing three separate single pole Reclosers plus a Controller that can selectively apply Single or Triple AutoReclose sequences to each pole asynchronously. Each pole has its own separate fault detection/Trip and AutoReclose sequencing capability. Different modes of operation can be set by the user to cater for the basic and or seasonal requirements of different types of load on the three phases. The Controller provides settings to enable the user to set the required options of Single/Triple Trip/Close and Single/Triple Lockout combinations including the option of what must happen under two-pole faults. Before setting the controller to Single pole Trip/Single pole Lockout mode the user must ensure that no plant is connected for which a three phase supply is essential e.g. three phase motor. A typical application is feeders supplying Oil Rig pumping motors, single pole ARC can be beneficially applied provided the motor is not run on two poles for extended periods otherwise NPS induced overheating and failure could result, the Single pole Trip - Three pole Lockout, Mode B, provides for this by allowing single pole trips followed by reclose but issues only three pole trips when a reclose is not started. An additional subsequent three pole trip is issued in this Mode if single pole autoreclose fails.

If Single pole Trip is set then each Recloser can each be independently Tripped and Closed as a single pole circuit breaker, however, in some circumstances all three Reclosers must be Tripped and Closed as a three pole device. Each Single pole Recloser, therefore, has its own independent Trip/Close circuits and CB Open/Closed Auxiliary contacts; also, its own Manual Trip & Lockout handle, with auxiliary T&LO contacts, operated by a Hot-Line working tool. The Control Cubicle must have pole by pole external push button switches to provide local electrical Trip/Close controls for each Recloser. The Controller provides pole by pole logic and interlocking to ensure that correct operation occurs in all modes and for all complex fault conditions. Three instances of the Capacitor Monitor/Test element are included to allow for the additional capacitor networks required by the phase segregated system.

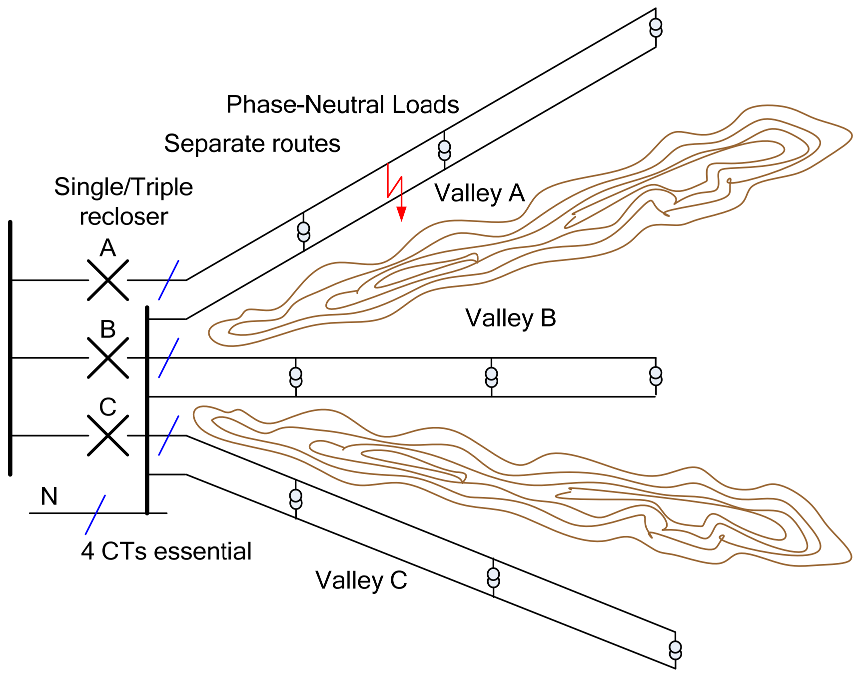


Figure 4.4-1 System Diagram showing application of Single/Triple pole Reclosers.

Single pole tripping is not normally applied where three-phase loads, or delta connected loads are connected. It is only applied to Reclosers on systems which allow Single pole to Neutral load connection, e.g. 4 wire, 3Phase + Neutral, systems, as typically used in the USA and South America. In such systems the routing and loading cab be such that loads can tolerate running for short periods on only two phases, the third being temporarily dead. As a simplified model consider that pole A is routed up valley A, Pole B is routed up valley B and pole C is routed up valley C; all with single phase to Neutral loads. A permanent phase to neutral fault and single pole Recloser sequence to Lockout on pole A will not, therefore, affect the supply to customers in valleys B and C.

For a fault at the position shown on Phase A, the A pole CB/Source Recloser will go through a sequence of Fast plus Delayed Trips to attempt to clear the A-G(N) fault. For a permanent A-G fault the outcome will be that pole A goes to Lockout and phase A will be left totally dead. Customers on Phases B and C will continue to receive uninterrupted supply, they will not suffer interruptions.

It should be noted that Single/Triple operation of Reclosers is applied to Rural Feeders and for these Loss Of Voltage (LOV) automation is not applied, (to do so would require a very complex LOV scheme requiring single pole closure of the NOP (TIE) and Feeder Reclosers with resultant single pole back-feed.). In the MLFB LOV Automation is not to be made available with Single /Triple Software.

Single-phase Tripping/Reclosing improves system reliability by maintaining supply to customers who are not on the faulted phase of a feeder. When a permanent fault occurs on one of the phases e.g. on the B phase, only the B pole Recloser performs a Trip and Reclose sequence, A and C phases, if unaffected, stay Closed maintaining supply to the Customers on poles A and C. If a single-phase reclosing sequence is unsuccessful because of a permanent fault, only the customers on the B phase are left without power, rather than all three-phases locking out. Single-phase operation will be applied, especially in rural areas where the majority of loads are single phase L-N and manual restoration can take longer because of the greater travel distances.

Note:- All unbalance Protection elements i.e. NPS, Broken Conductor, Loss of Phase, VTS, CTS, etc. algorithms have to be inhibited or pre-set to a long ride-through delay, BEFORE a single pole Recloser Trip is issued to prevent false operation during single-phase sequence Dead-Times, or inhibited when a single-phase Lockout state is reached. Because of the inherent unbalanced nature of three poles of single pole to neutral loads the NPS levels will be high on such systems and even higher when one pole trips out leaving only two poles energized, therefore, when Single pole Trip is selected all Unbalance protection elements are usually Inhibited. The ZPS will also be high, same level, but a considerable percentage will return via the Neutral conductor, therefore, a Neutral CT is essential, the rest via the multiple Ground paths.

4.4.2 Triple/Single Modes of Operation

The User may select one of three modes for the Single/Triple operation to suit the system load characteristics and thus avoid subjecting loads to conditions which could cause damage to plant. The settings of the Trip-Reclose-Lockout operation modes for the Recloser provide for three Modes of Trip Sequences to Lockout for a permanent fault. Mode selection can be via Settings menu to provide default mode, via Control Mode Menu, or via Settings Group change either in response to a General Command via SCADA or by Binary Input selection. If more than one mode is selected simultaneously, the priority is Mode A over B over C with Modes as defined below. When a binary input mapped to this function is energised, the setting is changed to the selected Mode. The setting does not revert to its previous state when the input is reset. The additional LEDs available on E12 Controllers can be used to show which Mode is ON. Only the selected Mode LED will be ON. Single Pole Reclosers can be operated by the User in any one of the following modes as and when the application requires it. Three single pole Reclosers connected in a full single pole wired scheme may thus be operated individually or together as a three pole Recloser as system operations require.

[It should be noted that Single/Triple operation only applies to Phase Fault elements and not to Earth Faults nor to Sensitive Earth faults. The use of three CTs, one per pole, and a single neutral CT i.e. 4 CTs, only allows detection that an SEF/Earth Fault has occurred but not on which pole. This determination is only possible if a Phase to Earth Fault current is above the Phase Fault Overcurrent setting, it is then possible to single pole trip and reclose as per the logic shown in tables in the Description of Operation section of this manual. Therefore, in the absence of any supplementary data, an SEF trip and/or Earth fault trip must cause Three pole Trip and Three pole Reclose.

MODE A 3PTrip-3PLO

This is the standard Three pole only mode of operation, only three pole Trip/Close sequences are performed and all three poles are Locked Out together when the Lockout state is reached. This mode is used where three phase loads such as motors cannot be allowed to on two phases, even for the duration of the autoreclose deadtime.

In this mode any pole CB Trip or CB Close Command must operate all three Reclosers.

In this mode a Line Check Trip or Trip & Lockout Command causes a **3PTrip-3PLO**.

In this mode any single manual Lockout Lever Command causes a **3PTrip-3PLO**.

In this mode the Hot Line On Command primes a single **3PTrip-3PLO**.

MODE B 1PTrip-3PLO

In this mode Controller can perform independent single pole TRIP sequences up to the point at which the Lockout state is reached on any one pole, it then performs a final three pole TRIP and all three

poles are Locked Out together. Controller only goes to **3PTrip-3PLO** if and when a 3P Trip and Lockout has to be performed. If at any point during an AutoReclose sequence a Phase-to-Phase or 3-Phase Fault condition develops and exists when a Trip output has to be issued i.e. if at the point at which a first pole element operates a starter is also raised on any other pole, then the Controller reverts to 3 pole Trip and 3 pole Close sequencing and **3PTrip-3PLO** as applicable at that point in the sequence.

This mode prevents detrimental LONG TERM 2 phase energisation of three phase loads e.g. motors.

In this mode 2 pole trips are never issued, any fault diagnosed as affecting more than 1 pole will cause a 3 pole trip which may be followed by 3 pole reclose.

Any fault on a healthy phase during a single pole reclose sequence on another phase will cause a 3 pole trip which may be followed by 3 pole reclose.

In this mode any single pole *CB Trip* or *CB Close* Command is considered to be a long term action and is therefore diverted to operate all three Reclosers.

In this mode a Line Check Trip or Trip & Lockout Command causes a **3PTrip-3PLO**.

In this mode any single manual Lockout Lever Command causes a **3PTrip-3PLO**.

In this mode, the single pole Trip and Reclose Command remains pole segregated.

In this mode the Hot Line On Command primes a single **3PTrip-3PLO.**

If ARC OFF is selected in Mode B all trips will be **3PTrip-3PLO**.

MODE C 1PTrip-1PLO

Mode C applies single pole tripping for all *Phase Fault* fault combinations. Each pole of the Recloser Controller follows its own settings and sequence independently. This is the equivalent of having three separately mounted single pole Reclosers each with its own Controller, each Recloser Controller is, therefore, unaware of the state of the Reclosers & Controllers on the other poles. This does mean that the sequences on each pole are not synchronous and are not interlocked, therefore, a fault scenario can develop where for a Phase to Phase fault one pole could be performing a Fast Trip the other could be performing a Delayed Trip, this is not an issue, one pole will initiate the tripping action(s) and if unsuccessful eventually both sequences will be doing delayed. Also different Dead times could be applicable on each of the poles at that point in the two sequences but Close commands issued by the Sequences are co-ordinated so that both poles close at the same time.

In this mode the Controller performs independent single pole Trip and Reclose sequences, each pole will Lockout independently. The Controller operates to drive each Recloser pole as an independent Circuit Breaker. Normal system operating modes will thus be 3P or 2P or 1P for extended periods, this determines the type of protection elements which can be enabled, Frequency elements and Voltage elements must track the remaining in-service phase(s). Controller does NOT revert to three-pole Trip and Close sequencing or three pole Lockout if a Phase to Phase Fault condition exists at any Trip point in the sequence.

In this mode all unbalance protection elements would usually be inhibited, i.e. NPS Overcurrent, NPS OverVoltage, VT Supervision, CT Supervision, and Broken Conductor. It is NOT expected that Directional elements will be applied as single pole tripping will change the polarising conditions for the sound poles.

In this mode a CBA Trip or CBA Close Command operates only on the A Pole Recloser, ditto for B and C poles.

In this mode 2 pole trips can be issued, any fault diagnosed as affecting 2 poles simultaneously will cause a 2 separate single pole trips which will be followed by two separate single pole reclose sequences. Close pulses to the two poles are aligned so that if the 2 trips were resultant from the same fault, re-strike does not occur from the two phases individually such that the fault is perpetuated by passing it from one phase to the other.

Any fault on a healthy phase during a single pole reclose sequence on another phase can cause a separate single pole trip which will be followed by separate single pole recloses with close pulses aligned.

In this mode any Line Check Trip will result in a **1PT - 1PLO**

In this mode a manual Lockout Lever Command on one pole only acts on that pole, there is no cross linking action to other poles. A Binary Input '79 Lockout' is required for each pole and each pole has its own manual Lockout counter.

In this mode the Hot Line On Command primes a single 3Pole Trip and Lockout **3PT - 3PLO**.

If ARC OFF is selected Modes A & B do 3P Trip & Lockout. Mode C does pole by pole **1PT - 1PLO**.

4.4.3 Pole Discrepancy

In Modes A and B the Recloser should not be left with 1 pole open for extended periods. This can occur if a single pole is opened in Mode C then the Mode is changed to A or B. A Pole Discrepancy output is available which is driven in Mode A and B only, to indicate that all poles of the recloser are not in the same state. An associated timer, PD Time Delay is set in the Circuit Breaker menu. This output can be used as an alarm or to cause a three pole trip.Quick Logic Applications

4.4.4 Auto-Changeover Scheme Example

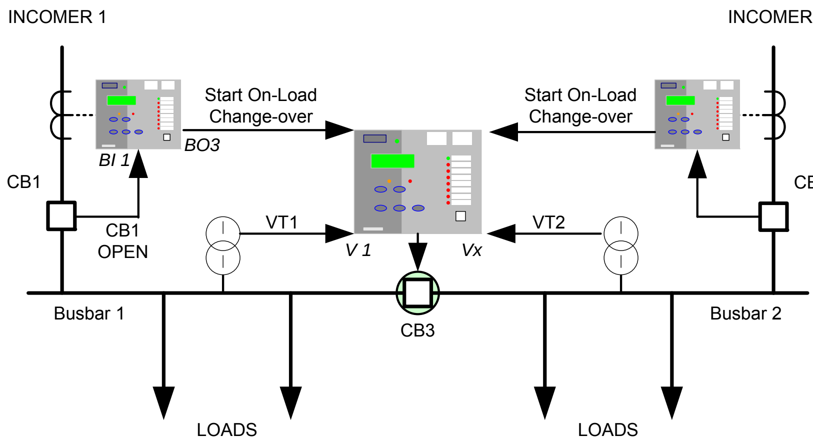


Figure 4.4-2 Example Use of Quick Logic

The MV installation illustrated above is fed from two incomers. To limit the substation fault level the busbar is run with CB3 open. When a fault occurs on one of the incomers it is isolated by the circuit protection. To re-supply the disconnected loads from the remaining incomer CB3 is closed.

If the line fault occurs on incomer 1 it must be confirmed that CB 1 has opened before CB3 can be closed. The relay on incomer 1 confirms that a trip has been issued to CB1 (e.g. Binary Output 2), that CB 1 has opened (e.g. Binary Input 1) and that no current flows in the circuit (e.g. 37-1 = Virtual 1):

<u>Incomer 1 Relay is Configured:</u>

CB1 Open auxiliary switch wired to B.I. 1

Trip output to CB1 = B.O. 2

OUTPUT CONFIG>OUTPUT MATRIX: ***37-1*** **= V1**

OUTPUT CONFIG>OUTPUT MATRIX: ***E1*** **= BO3**

CONTROL & LOGIC>QUICK LOGIC: ***E1*** **= O2.I1.V1**

The output from Incomer 1 (BO3) relay is input to the relay on CB 3 (Binary Input 1). A panel switch may be used to enable the On-Load Change-over scheme (Binary Input 2). Before Closing CB3 a check may be made that there is no voltage on busbar 1 (27/59-1 = Virtual 1). CB 3 is closed from Binary Output 3.

<u>CB3 Relay is Configured:</u>

Panel switch (ON-Load Change-over Enabled) wired to B.I. 1

OUTPUT CONFIG>OUTPUT MATRIX: ***27/59-1*** **= V1**

OUTPUT CONFIG>OUTPUT MATRIX: ***E1*** **= BO3**

CONTROL & LOGIC>QUICK LOGIC: ***E1*** **= I1.I2.V1**

If required a time delay can be added to the output using the CONTROL & LOGIC > QUICK LOGIC: ***E1 Pickup Delay*** setting**.**

Section 5: Supervision Functions

5.1 Circuit-Breaker Fail (50BF)

Where a circuit breaker fails to operate to clear fault current the power system will remain in a hazardous state until the fault is cleared by remote or back-up protections. To minimise any delay, CB Failure protection provides a signal to either re-trip the local CB or back-trip 'adjacent' CBs.

The function is initiated by the operation of user selectable protection functions or from a binary input. Current flow is monitored after a tripping signal has been issued if any of the 50BF current check elements have not reset before the timers have expired an output is given.

The relay incorporates a two-stage circuit breaker fail feature. For some systems, only the first will be used and the CB Failure output will be used to back-trip the adjacent CB(s). On other systems, however, this output will be used to re-trip the local CB to minimise potential disruption to the system; if possible via a secondary trip coil and wiring. The second CB Failure stage will then be used to back-trip the adjacent CB(s).

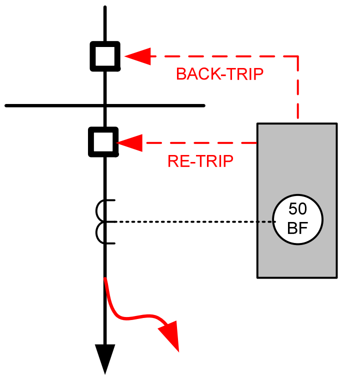


Figure 5.1-1 - Circuit Breaker Fail

5.1.1 Settings Guidelines

<u>50BF Setting</u>

The current setting must be set below the minimum protection setting current.

<u>50BF DTL1/50BF DTL2</u>

The time delay setting applied to the CB Fail protection must be in excess of the longest CB operate time + relay reset time + a safety margin.

First Stage (Retrip)	
Trip Relay operate time	10ms
7SR224 Reset Time	20ms
CB Tripping time	80ms
Safety Margin	40ms
Overall First Stage CBF Time Delay	**150ms**

Second Stage (Back Trip)	
First CBF Time Delay	120ms
Trip Relay operate time	10ms
7SR224 Reset Time	20ms
CB Tripping time	80ms
Margin	60ms
Overall Second Stage CBF Time Delay	**290ms**

The safety margin is extended by 1 cycle for the second CBF stage as this will usually involve a back-trip of a Busbar tripping scheme.

The timing sequence for each stage of the circuit breaker fail function is as below.

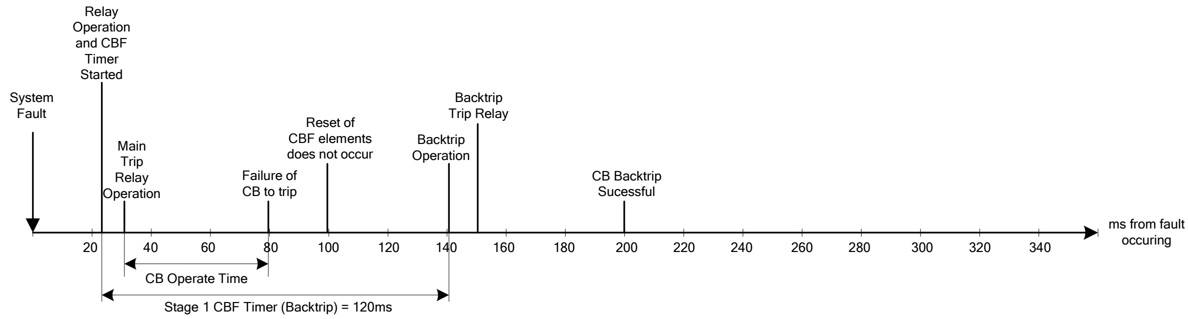


Figure 5.1-2 - Single Stage Circuit Breaker Fail Timing

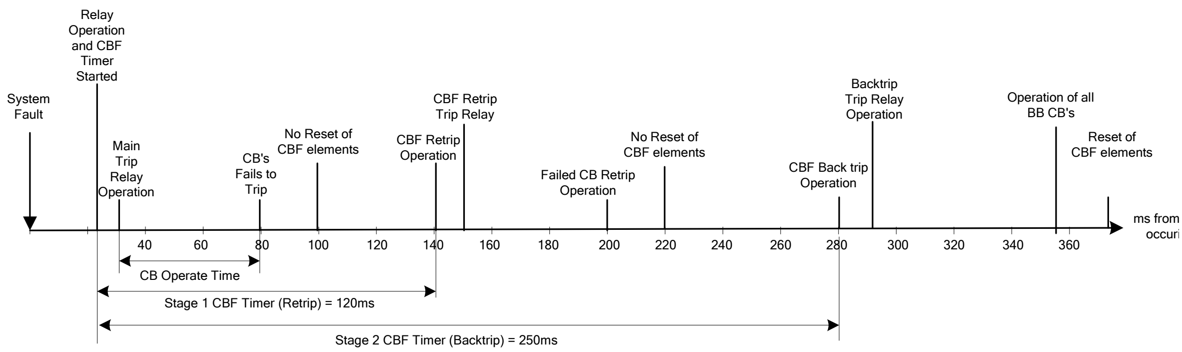


Figure 5.1-3 - Two Stage Circuit Breaker Fail Timing

5.2 Current Transformer Supervision (60CTS)

When a CT fails, the current levels seen by the protection become unbalanced. A large level of NPS current is therefore detected - around 0.3 x In for one or two CT failures. However this condition would also occur for a system fault. To differentiate between the two conditions, the element uses NPS voltage to restrain the CTS algorithm as show in the accompanying table.

NPS Current	**NPS Voltage**	**Decision**
> Setting	> Setting	System Fault
> Setting	< Setting	CT Failure

Table 5-1 Determination of VT Failure (1 or 2 Phases)

Following a CT Failure, there should be little or no NPS voltage. Perhaps 0.1 x Vn as a maximum.

Operation is subject to a time delay to prevent operation for transitory effects.

A 3-phase CT failure is considered so unlikely (these being independent units) that this condition is not tested for.

5.3 Voltage Transformer Supervision (60VTS)

Although VTs rarely fail themselves, VT Supervision presents a common application because of the failure of protective Fuses connected in series with the VTs.

When a VT failure occurs on one or two phases, the voltage levels seen by the protection become unbalanced. A large level of NPS voltage is therefore detected - around 0.3 x Vn for one or two VT failures. However this condition would also occur for a system fault. To differentiate between the two conditions, the element uses NPS current to restrain the VTS algorithm as show in the accompanying table.

NPS Voltage	**NPS Current**	**Decision**
> Setting	> Setting	System Fault
> Setting	< Setting	VT Failure

Table 5-2 Determination of VT Failure (1 or 2 Phases)

Following a VT Failure, the level of NPS current would be dependent solely upon load imbalance - perhaps 0.1 x In as a maximum.

Operation is subject to a time delay to prevent operation for transitory effects.

NPS voltage and current quantities are used rather than ZPS since the latter makes it difficult to differentiate between a VT failure and a Phase-Phase fault. Both conditions would generate little or no ZPS current. However the element provides an option to use ZPS quantities to meet some older specifications.

There are possible problems with using NPS quantities due to load imbalances. These would also generate significant levels of NPS current and so possibly cause a VT failure to be missed. This problem can be overcome by careful selection of settings, however, setting the NPS current threshold above the level expected for imbalance conditions.

If a failure occurs in all 3 Phases of a Voltage Transformer, then there will be no NPS or ZPS voltage to work with. However the PPS Voltage will fall below expected minimum measurement levels.

This could also be due to a ‘close in’ fault and so PPS Current must remain above minimum load level BUT below minimum fault level.

PPS Voltage	**PPS Current**	**Decision**
< Setting	> Minimum Fault Level	System Fault
< Setting	Minimum Load Level < AND < Minimum Fault Level	VT Failure

Table 5-3 Determination of VT Failure (3 Phases)

Operation is again subject to a time delay to prevent operation for transitory effects.

Alternatively a 3 Phase VT failure can be signalled to the relay via a Binary Input taken from the Trip output of an external MCB. This can also be reset by a Binary Input signal.

VTS would not normally be used for tripping - it is an alarm rather than fault condition. However the loss of a VT would cause problems for protection elements that have voltage dependant functionality. For this reason, the relay allows these protection elements - under-voltage, directional over-current, etc. - to be inhibited if a VT failure occurs.

5.4 Trip-Circuit Supervision (74TCS)

Binary Inputs may be used to monitor the integrity of the CB trip circuit wiring. A small current flows through the B.I. and the trip circuit. This current operates the B.I. confirming the integrity of the auxiliary supply, CB trip coil, auxiliary switch, C.B. secondary isolating contacts and associated wiring. If monitoring current flow ceases, the B.I. drops off and if it is user programmed to operate one of the output relays, this can provide a remote alarm. In addition, an LED on the relay can be programmed to operate. A user text label can be used to define the operated LED e.g. “Trip CCT Fail”.

The relevant Binary Input is mapped to 74TCS-n in the INPUT CONFIG>INPUT MATRIX menu. To avoid giving spurious alarm messages while the circuit breaker is operating the input is given a 0.4s Drop-off Delay in the INPUT CONFIG>BINARY INPUT CONFIG menu.

To provide an alarm output a normally open binary output is mapped to 74TCS-n.

5.4.1 Trip Circuit Supervision Connections

The following circuits are derived from UK ENA S15 standard schemes H5, H6 and H7.

For compliance with this standard:

Where more than one device is used to trip the CB then connections should be looped between the tripping contacts. To ensure that all wiring is monitored the binary input must be at the end of the looped wiring.

Resistors must be continuously rated and where possible should be of wire-wound construction.

Scheme 1 (Basic)

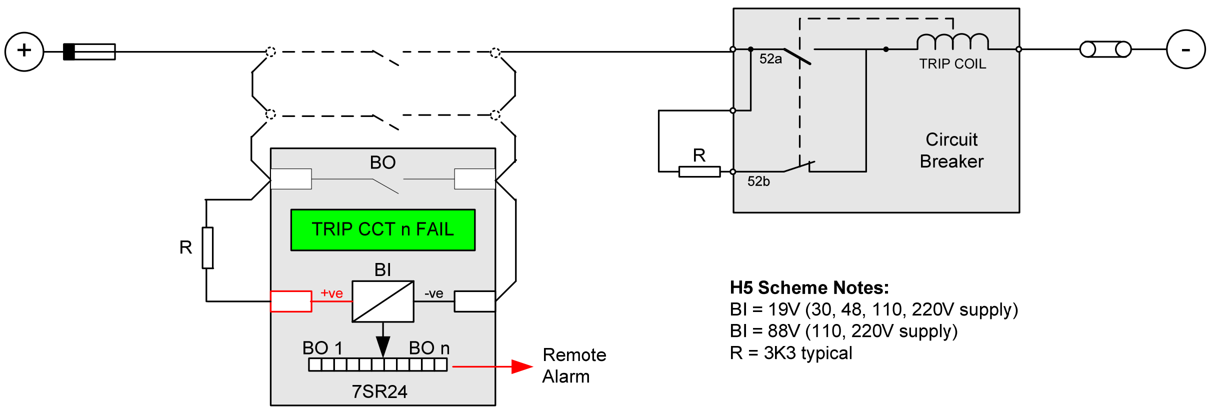


Figure 5.4-1: Trip Circuit Supervision Scheme 1 (H5)

Scheme 1 provides full Trip and Close supervision with the circuit breaker Open or Closed.

Where a ‘Hand Reset’ Trip contact is used measures must be taken to inhibit alarm indications after a CB trip.

Scheme 2 (Intermediate)

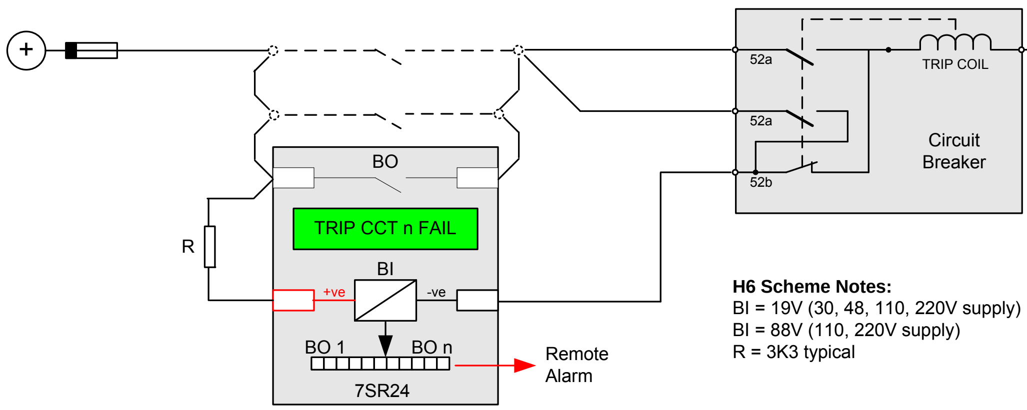


Figure 5.4-2: Trip Circuit Supervision Scheme 2 (H6)

Scheme 2 provides continuous Trip Circuit Supervision of trip coil with the circuit breaker Open or Closed. It does not provide pre-closing supervision of the connections and links between the tripping contacts and the circuit breaker and may not therefore be suitable for some circuits which include an isolating link.

Scheme 3 (Comprehensive)

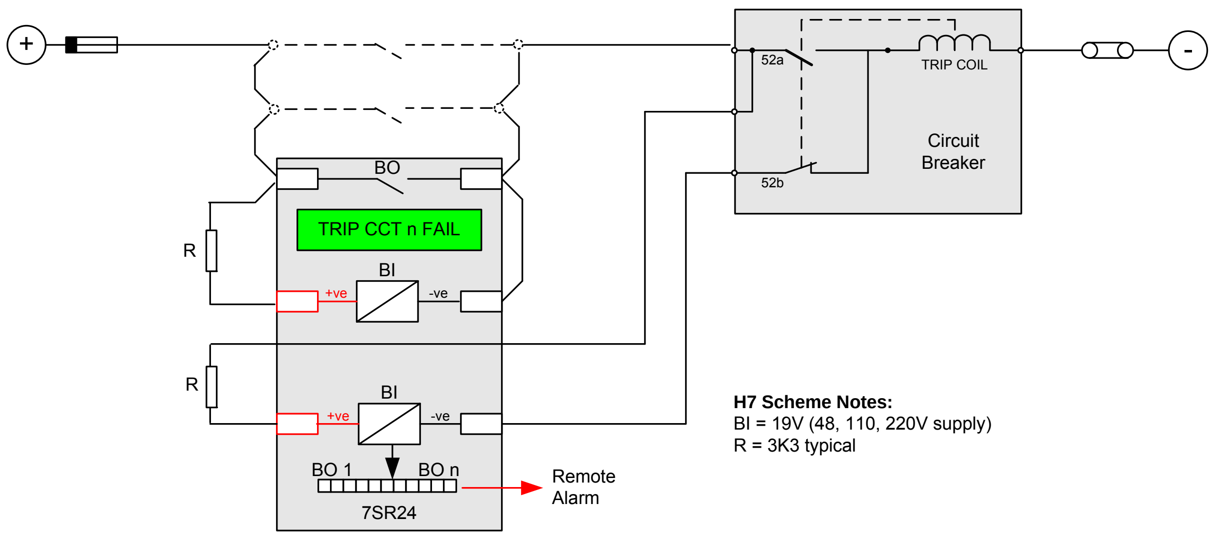


Figure 5.4-3: Trip Circuit Supervision Scheme 3 (H7)

Scheme 3 provides full Trip and Close supervision with the circuit breaker Open or Closed.

5.5 Inrush Detector (81HBL2)

This element detects the presence of high levels of 2nd Harmonic current which is indicative of transformer Inrush current at switch-on. These currents may be above the operate level of the overcurrent elements for a short duration and it is important that the relay does not issue an incorrect trip command for this transient network condition.

If a magnetic inrush condition is detected operation of the overcurrent elements can be blocked.

Calculation of the magnetising inrush current level is complex. However a ratio of 20% 2^{nd} Harmonic to Fundamental current will meet most applications without compromising the integrity of the Overcurrent protection.

There are 3 methods of detection and blocking during the passage of magnetising inrush current.

Phase	Blocking only occurs in those phases where Inrush is detected. Large, Single Phase Transformers – Auto-transformers.
Cross	All 3-phases are blocked if Inrush is detected in any phase. Traditional application for most Transformers but can give delayed operation for Switch-on to Earth Fault conditions.
Sum	Composite 2nd Harmonic content derived for all 3-phases and then compared to Fundamental current for each individual phase. Provides good compromise between Inrush stability and fast fault detection.

Table 5-4 Magnetic Inrush Bias

5.6 Broken Conductor / Load Imbalance (46BC)

Used to detect an open circuit condition when a conductor breaks or a mal-operation occurs in phase segregated switchgear.

There will be little or no fault current and so overcurrent elements will not detect the condition. However the condition can be detected because there will be a high content of NPS (unbalance) current present.

An NPS / PPS ratio > 50% will result from a Broken Conductor condition.

Operation is subject to a time delay to prevent operation for transitory effects.

5.7 Circuit-Breaker Maintenance

The Relay provides Total, Delta and Frequent CB Operation Counters alongwith an I^2t Counter to estimate the amount of wear and tear experienced by a Circuit-Breaker. Alarm can be provided once set levels have been exceeded.

Typically estimates obtained from previous circuit-breaker maintenance schedules are used for setting these alarm levels. The relay instrumentation provides the current values of these counters.