7PG2113/4/5/6

Feeder Protection

Document Release History

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Section 1: Pilot Wire Current Differential Scheme

1.1 General

The 7PG2113 and 7PG2114 relays provide both pilot wire current differential protection and overcurrent and earth fault protection as well as other additional functions. The 7PG2115 and 7PG2116 additionally provide directional functionality for the overcurrent and earth fault protection. The Overcurrent and earth fault functions are typically configured to provide an Overcurrent and Earth fault Guard function and can also provide backup protection for the current differential function.

The current differential trip contacts can be connected in series with the contacts of an Overcurrent Guard relay to avoid operation for damaged pilots during normal levels of load current. The 7PG2113, 7PG2114, 7PG2115 and 7PG2116 relays provide both the Pilot Wire differential protection and the Guard function as well as other additional protection functions.

Additional external Pilot Supervision equipment can be supplied to detect pilot cable open circuit which can lead to protection operation.

Solkor R and Solkor Rf are well established pilot wire feeder differential protections operating on the current balance principle and are suitable for application on privately owned 2 core pilots with loop resistance up to 2000ohms to protect 2 ended feeder circuits up to 20km in length. Two identical relays are used as a pair with one relay connected to current transformers at each end of the feeder respectively.

The relay has an insulation level of 5kV between pilot connections and the local ground to withstand voltages induced on the pilot cable due to coupling with the fault current flowing in a parallel path and to withstand differential ground voltages caused by the flow of fault current. This is generally adequate for distribution feeders but for higher voltage systems where feeders may be longer and fault levels higher, an additional external isolation transformer is available for use with the relay in Rf mode to increase the voltage withstand to 15kV. One transformer should be fitted at each end of the pilot connection.

The R/Rf relay is primarily intended for use in the Rf mode which has the advantage of increased operating speed but can be simply changed to R mode for compatibility with pre-installed remote end relays which are older 5kv Solkor R type relays. The 7PG2113/4/5/6 Solkor relays and 7PG2111 Solkor R/Rf relays are not compatible with the older 15kv Solkor R system, Solkor A or Solkor B.

1.2 Information required when ordering

7PG2113/4/5/6 Protection relay

- CT secondary Current Rating
- Insulation level (5/15kV)
- Set as R or Rf mode
- Non Directional / Directional Overcurrent & Earth Fault
- Auxiliary DC supply
- Binary Input/Output requirements

External Pilot Supervision devices

- Case Styles
- System Frequency (50/60Hz) (used for B22 relay setting)
- Send or Receive End
- Insulation level (5/15kV)
- Auxiliary DC supply

Intertripping

- Intertripping is not compatible with 7PG2113/4/5/6 used as Guard Relays

1.3 Equipment Options

The following equipment lists provide an overview of the equipment normally required, highlighting differences for the various scheme options. These lists should be used in conjunction with the diagrams that follow.

1.3.1 Solkor Plain/Overcurrent Protection Schemes

7PG2113/4/5/6 relay (5kV), 1 per feeder end

15kV isolation transformer, 1 per feeder end if required

1.3.2 Pilot Supervision 5kV Schemes

1.3.2.1 Send End

Pilot Supervision Send End relay (transformer+rectifier), 1 per circuit

B22 AC Supply Supervision relay, 1 per circuit

1.3.2.2 Receive End

Pilot Supervision Receive End relay (B74 & B75), 1 per circuit

Note: Although the 5kV scheme utilises a combined B75/B74 unit, the additional isolation requirements at 15kV necessitate that separate units must be used.

1.3.3 15kV Schemes

1.3.3.1 Send End

15kV Pilot Supervision Send End relay (transformer+rectifier), 1 per circuit

B22 AC Supply Supervision relay, 1 per circuit. 5kV insulation as this is not connected to the pilots.

1.3.3.2 Receive End

15kV B75 relay, 1 per circuit

B74 relay, 1 per circuit

Note: Although the 5kV scheme utilises a combined B75/B74 unit, the additional isolation requirements at 15kV necessitate that separate units must be used.

1.4 Application Diagrams

The R or Rf mode of the relays at each end must be the same. This applies to any of the arrangements shown.

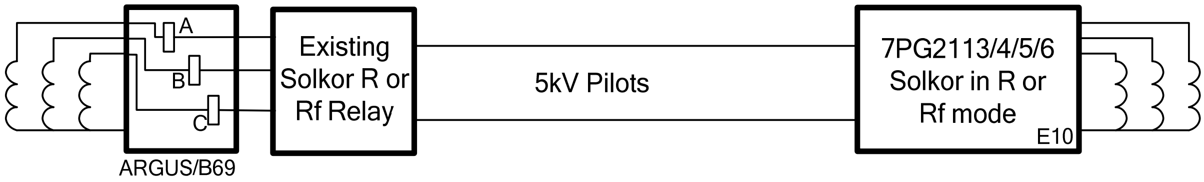


Figure 1.4-1 Installation with Existing Solkor R, Rf or R/Rf relay.

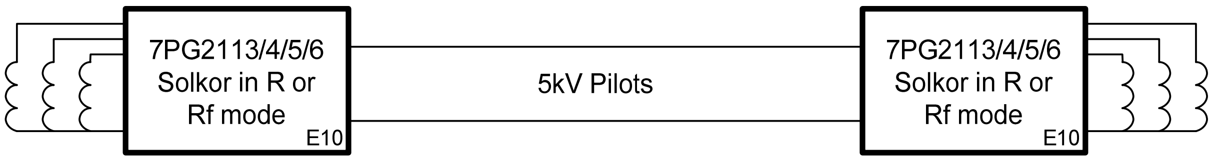


Figure 1.4-2 Standard 5kV Solkor R/Rf with Guard.

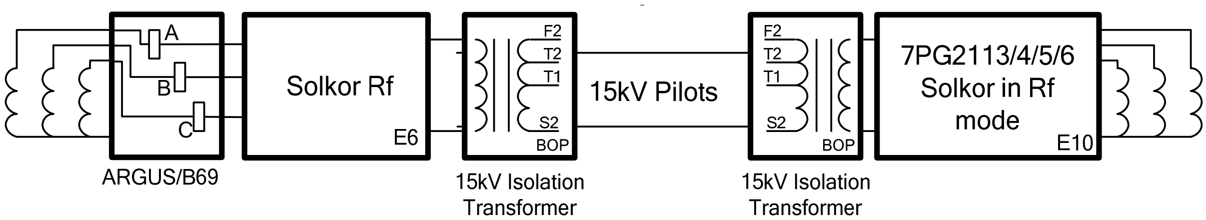


Figure 1.4-3 Installation with existing 15kV Plain Solkor Rf with Guard.

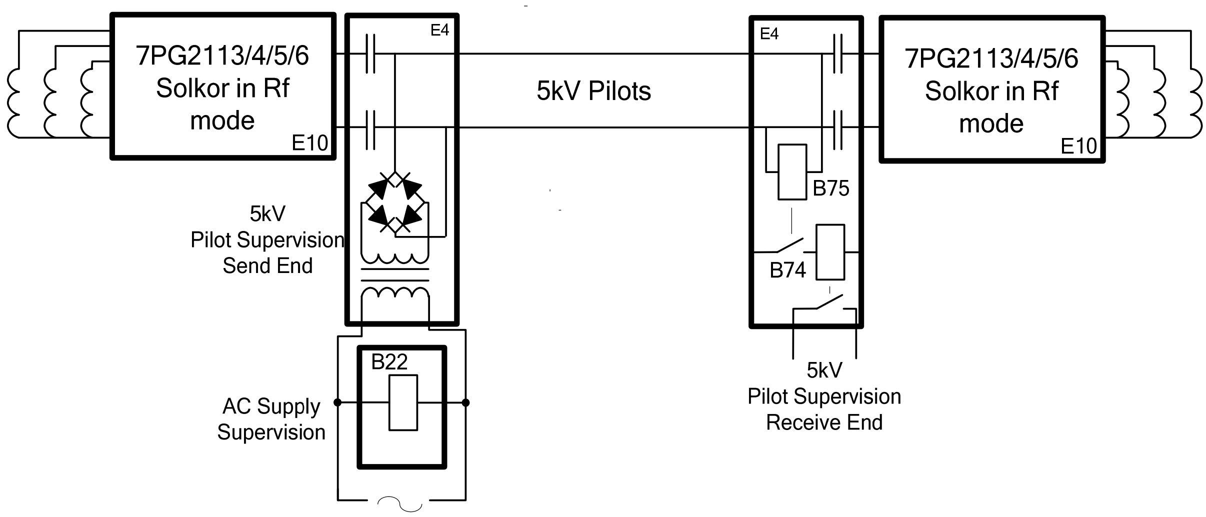


Figure 1.4-4 5kV Solkor Rf with Pilot Supervision.

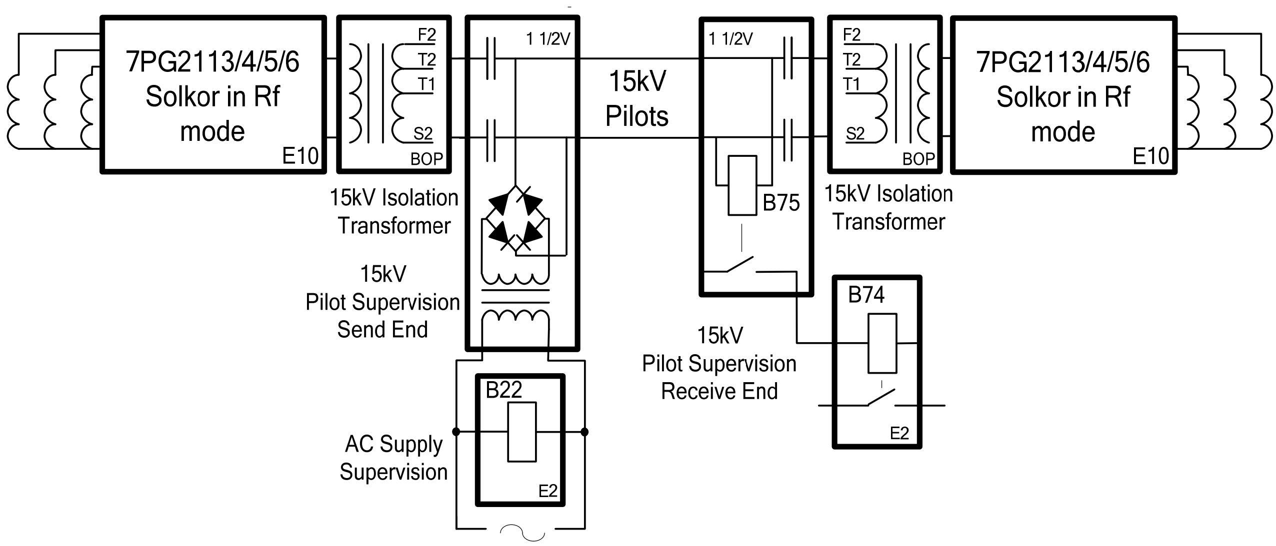


Figure 1.4-5 15kV Solkor Rf with Pilot Supervision.

1.5 Essential External Wiring and Settings

The relay requires external wiring connections to provide the interaction between the electromechanical pilot wire differential module and the numeric module. This wiring is not fitted at the factory which allows the customer to customise wiring routing and ferrule marking to suit customer preference and site specific requirements. Current transformer wiring must be fitted in line with the standard diagrams to connect the Solkor module and numeric module. Input/output interconnections are required to take advantage of the features provided by the numeric module. Details of this wiring is shown on the product wiring diagrams and in Chapter 5: Installation, in this manual.

The settings supplied in the 4 available settings groups are designed to provide a typical scheme for use as a basis for site specific settings to suit the required application. These settings provide the functionality of Overcurrent and Earth Fault Guard, Backup Overcurrent and Earth Fault and monitoring of the Pilot Wire protection.

It is recommended that the tripping contact of the Pilot wire protection is hardwired via a Guard contact to the circuit breaker. Additional delay caused by routing this signal into a binary input to apply programmable logic in the numeric module is undesirable. Instead, the simple Guard logic is achieved by series connection of the two contacts and an additional contact from the pilot wire module should be wired into the numeric module to provide an alarm signal which is used to provide auxiliary functions. This signal is used to drive indication, raise an event on the comms protocol , initiate a waveform record and can be used to drive additional repeat contacts and as an input to additional user logic.

Similarly, the Guard relay contact which is driven from Overcurrent and Earth Fault elements should be set to operate a contact which is wired in series with the circuit breaker trip coil. This contact can be set to be operated continuously by energising the Guard Override Binary Input. This contact can also be shorted out externally by a panel switch to physically remove the Guard function. This method ensures that the CB can still trip with the Guard relay de-energised or removed.

The Backup Overcurrent and Earth Fault function can provide a separate contact for CB tripping. An inhibit input is configured for this function also so that the backup protection can be switched off.

Internal user logic is programmed in the settings file to provide trip indication when the Solkor Rf module operates co-incidentally with the OC/EF Guard. Operation of the Solkor Rf module in the absence of a Guard relay pickup is indicated separately. This can indicate a problem with the pilot connection but Guard settings must be considered in this conclusion since this indication will be raised if a low level fault can occur below the settings of the Guard but high enough to operate the differential protection. Time delay settings can be applied to avoid nuisance indications.

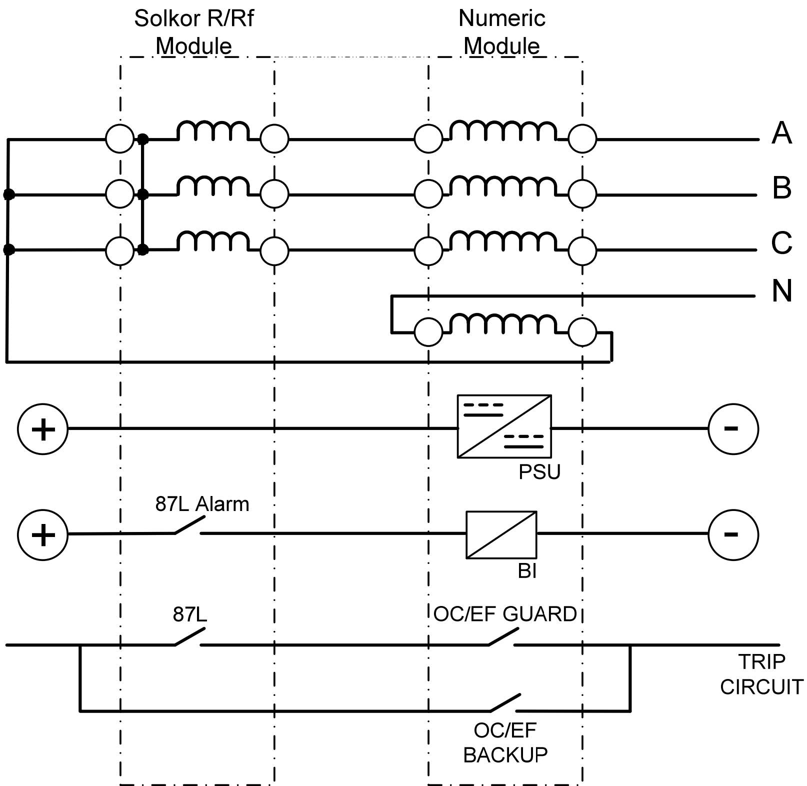


Figure 1.5-1 Interconnection Wiring

1.5.1 Description of Typical Setting file.

1.5.1.1 Relay Binary Inputs

Reference (e.g. I1 =Binary Input 1)	Connection	Description
I1	Energised from Solkor R/Rf module contact.	This triggers indication and a waveform record regardless of the Guard relay/Trip.(A separate contact is wired externally via a Guard contact for the trip circuit.)
I2	Energised from Guard Override panel switch (latched)	The switch must also short the external guard contact to allow removal/switch off of relay DC
I3	Backup OC/EF Inhibit from a panel switch (latched)	Mapped as an inhibit on 51-2

1.5.1.2 User Logic

Reference	Setting	Description
V1	50-1 or 50G-1 Guard elements operated	This is used to generate the Trip indication for 87L+Guard or 87L+ Guard Override
E1	I1.!V1.!I2	87L without Guard when Guard Override is not raised Used to indicate a possible pilot open circuit, (Low level faults below the guard setting may cause nuisance indications)
E2	(I1.V1)+(I1.I2)	Indication of trip condition, (87L and Guard operation) or (87L when Guard Override is raised). This is an indication of trip condition, it is used to start Waveform Recorder and Fault Record. It is also operates the Trip output contact used by Backup OC/EF although it is expected that the main trip will be direct from the Solkor R/Rf module output contactor via a Guard contact/guard override switch connected externally

1.5.1.3 Relay Binary Outputs

Reference (e.g. O1 =Binary Output 1)	Setting	Description
O1	Protection Healthy	
O2	Guard Relay Operated (50-1 & 50G-1) & also Guard Override	This is the main Guard contact for the trip circuit
O3	87L Solkor operated	This is for alarm/test only
O4	Backup Overcurrent, Earth Fault & E2 (=87L+Guard or 87L+Guard Override))	This is the trip output which starts a Fault Record
O5	E1 (=87L without Guard)	This gives an alarm that the Solkor has tripped without the Guard This could indicate pilot open circuit (note that a fault occurs below the Guard setting but above the Rf setting will create an alarm)

1.5.1.4 LED mapping

Reference	Setting	Description
L1	87L operation (Red)	With or without Guard
L2	Backup OC & EF (Yellow Pickup, Red Trip)	
L3	Guard OC & EF, (Yellow, self reset)	
L4	A (Yellow, self reset)	Phase leds are illuminated for Guard and Backup and are self reset, led state is stored in the Fault display for Backup and 87L trips. i.e. Guard operated phase leds are shown for Solkor trips.
L5	B (Yellow, self reset)	
L6	C (Yellow, self reset)	
L7	Earth (Yellow, self reset)	Operated by Backup EF & Guard EF, Self reset to match A,B&C indications
L8	Guard Override (Yellow)	Self reset, follows binary input
L9	Backup inhibited (Yellow)	Self reset, follows binary input

1.6 Application Considerations

1.6.1 Overcurrent Guard

Traditional Guard relays are connected to the same CTs as the current differential protection relay and the output contacts are connected in series such that a differential operation will not cause a CB trip if the current in the guard relay (and therefore the local end) is below setting. This functionality is achieved in the 7PG2113-6 relays by the overcurrent and earth fault elements that are provided in the numeric module.

Default relay settings on the numeric module provide this functionality along with the recommended external wiring.

Phase fault Guard relays should be set to at least 150% of maximum load current for stability but less than 50% of the minimum expected phase fault current. These 2 requirements may conflict and a compromise may be required.

Earth fault guard relays should be set to less than 50% of the minimum earth fault but more than 150% of the maximum residual expected due to load imbalance. It is important to note that if an electromechanical, variable setting relay is used as a guard relay, if a low setting is selected the AC burden at rating will be increased. This is not the case when a modern numerical relay such as the 7PG2113-6 since this will have a fixed burden independent of the relay setting. The lower burden of the numeric relay may be a major advantage in this application.

Care should be taken when applying guard relays that the fault infeed will be available to operate the guard relay for all fault types. Application of Guard relays to radial systems may be limited.

1.6.2 5/15kV Isolation Voltage

Any electrical current which flows in a path parallel to the pilot cable will cause a voltage to be induced along the pilot cable. This voltage can become significant for large values of current, long lengths of parallel path and higher mutual coupling factors caused by poor screening or close proximity of current paths. This voltage can lead to flashover inside of the relay case from the circuits connected to the pilots to the relay case and local ground. The problem can be worsened by ground voltage shift between the two substations at the feeder ends due to earth fault current. Earth shift voltage is often ignored in cable power systems because of the high percentage of the earth fault current which returns through the cable sheath and armouring, however with overhead line systems the earth shift voltage can be as significant as the induced longitudinal voltage.

The 7PG2113/4/5/6 relay will withstand 5kV rms voltage. This can be increased to 15kV by the addition of an isolation transformer.

5kV isolation is usually acceptable for 11kV cable distribution systems where zero sequence currents are relatively low and protected feeder lengths and therefore parallel runs are relatively short. For higher voltages where longer feeder lengths are common15kV insulation may be required but 5kV may be acceptable if fault levels are low or feeder lengths are short.

The pilot cores should be allowed to ‘float’ with neither core earthed at either end. Capacitive coupling to the local ground along the cable length will ensure that voltage at either end will cause the pilot voltage to remain symmetrical to the ground voltage such that the withstand requirement at each end is approximately half of the longitudinal induced voltage.

Induced voltage is proportional to parallel length, maximum parallel current and the coupling or screening factor between the pilot and the current path. This can be very difficult to assess accurately by calculation and cannot generally be measured.

The maximum current is generally accepted as the EARTH fault level for an out of zone fault. Although a phase-phase or 3-phase fault may have a higher fault current, the fault current for these faults will return locally in a parallel path in the opposite direction i.e. in the other phase(s). With an earth fault, the return path may be distant or non-parallel with the pilot such that the net current which couples to the pilot can be considered maximum for the earth fault. The through fault current level is used in combination with the total feeder length as a worst case scenario because although an internal fault may have a greater fault current, the parallel path will be shorter by definition.

1.6.3 Pilot Cables

The above considerations of insulation and balance between cores, it is evident that pilot cables for use with pilot wire current differential feeder protection are required to have special consideration when long lengths and high fault currents are involved. It is also apparent that the effects are not easily analysed or modelled and thus in-service experience is the most reliable basis in deciding which types of pilot will be satisfactory.

The UK has vast experience of the use of pilot wire differential feeder protection and the UK supply industry specification on multipair cables, ESI Standard 09-6 is therefore particularly applicable as a reference for pilot wire requirements.

It should be noted that the voltage between cores in the pilots is limited by the non-linear resistors which are connected across the summation transformers in the Solkor relays at the ends. Also note that any induced voltage will be at an equal level per unit length in all cores and screen. Thus it is possible to use pilots with 500v grade insulation between cores and core to screen. The 5 or 15kV insulation requirement exists only between 'internal cores and screen' to the local earth. Similar considerations should be observed at any cable terminations where standard 500v terminals can be used but the whole terminal block should be mounted on an insulating baseplate to comply with insulation requirements to the local ground. Terminals should be shrouded and clearly marked since during a system fault (included a fault on any parallel feeder, not only the protected circuit) the induced voltage may pose a serious risk to health. Inside of the protection panel, the insulation to local earth and segregation of wiring for health and safety purposes may be more easily achieved by the use of separate cable trunking which can be routed independently and clearly marked rather than by the use of special cabling inside of the panel. Special precautions will be required when terminating or handling pilot connections.

Pilot inter-core capacitance has the effect of shunting the relays in the current balance scheme. As the capacitance increases a point is reached where the shunt impedance has a significant effect on the relay settings. This produces a maximum limit for pilot capacitance which can be used with the relay. With the relays in the Solkor R connection mode the pilot capacitance maximum limit is 2.5μF and with the Solkor Rf connection mode this limit is 0.8μF. These limits can be increased for the Solkor Rf mode by the use of transformer tappings if the 15kV isolation transformers are used. The limits are 1μF, 2μF and 4μF which impose accompanying pilot LOOP resistance limits of 1760Ω, 880Ω and 440Ω respectively.

The pilot resistance is used in conjunction with settable padding resistance to achieve the stability biasing of the relay. The padding resistance must be set in series with the pilot resistance to achieve a standard value. There is therefore a maximum value for the pilot resistance for which the padding should be set to zero. The maximum value of pilot LOOP resistance for the Solkor R mode is 1000Ω and for the Solkor Rf mode the maximum LOOP resistance is 2000Ω. When 15kV isolation transformers in the Rf mode the maximum LOOP resistance will be reduced to 1760Ω to compensate for the transformer winding resistance and if the transformer taps are used to compensate for the effects of pilot capacitance the maximum LOOP resistance is reduced further to values of, 880Ω and 440Ω depending on the tap used. The actual pilot resistance must be referred through the transformer at the chosen tap to give an equivalent pilot resistance value to which the padding should be added.

Thus the padding resistance R = (Sv-Rp)/(2T)

Where Rp = Pilot LOOP resistance

Sv = standard value

=1000Ω for Solkor R mode (T=1)

=2000Ω for 5kV Solkor Rf mode (without transformers) (T=1)

=1760Ω for Solkor Rf with 15kV transformers using tap 1 (T=1)

=880Ω for Solkor Rf with 15kV transformers using tap 0.5 (T=0.5)

=440Ω for Solkor Rf with 15kV transformers using tap 0.25 (T=0.25)

1.6.4 Pilot Supervision

Pilot supervision is used to detect failure of the pilot connection. Open circuit Pilots will lead to a loss of the balance current from the remote end which will tend towards a differential trip condition. Pilot Supervision is often applied as standard with the Solkor system but may be considered unnecessary at lower voltages or in an interconnected system where unnecessary tripping of an un-faulted feeder may be tolerated due to limited consequences in terms of loss of supply and relatively low probability of pilot damaged or failure when compared to the additional equipment cost.

The Pilot Supervision system uses DC injection which cannot pass through a transformer. For this reason the Pilot Supervision must be applied at the pilot side of the 15kV isolation transformers if fitted and therefore the devices must have an isolation level to suit. The Send End unit and B75 Receive End must have 15kV insulation. The B22 Supervision Relay and B74 Repeat Relay are not connected to the pilots directly and no special isolation requirements apply to these devices.

1.6.5 Injection Intertripping

Injection Intertripping is generally difficult to apply successfully in conjunction with Overcurrent Guard relays since the remote Guard relay will block operations resulting from intertrip injection if the remote end CT current is below the Guard setting.

Injection intertripping is used to force the remote end circuit breaker to trip for local protection operation. This is generally started by protection other than the Solkor system since a differential protection system will generally trip on differential current at both ends regardless of the local current level.

1.6.6 Capacitive Charging Currents

Significant electrical capacitance exists between HV primary conductors and the adjacent earth such that a capacitive charging current will exist with any energised line. The level of current is dependent on the system voltage, the feeder length and the construction including materials and proximity of earthed conductors. The highest levels are found in separate phase, individually screened and armoured conductors with lowest levels found on overhead line feeders. These currents are generally supplied from one end only as balanced 3 phase and as such constitute a differential current to the relays but is usually significantly lower than relay 3P setting.

During out of zone earth faults however, the voltage on the faulted phase may be significantly depressed such that the charging current is reduced. The Solkor summation transformer will measure charging current on two phases only and interpret this as a residual differential current for which relay settings are significantly lower than for 3P balanced differential current. This issue is compounded in systems which are not solidly earthed because the unfaulted phase voltage may increase, leading to increased charging current on these phases, during an earth fault. The transient switching of charging current limits the maximum charging current to 1/3 of the most sensitive earth fault setting for solidly earthed systems or 1/9 of the most sensitive earth fault setting for resistance earthed systems.

On higher voltage systems, where separate single phase cables are more commonly used and feeders are generally longer it is common to find phase segregated Solkor Rf systems where 3 separate Solkor relays are fitted at each end, each connected to a separate pairs of pilots with one phase of the system CT connected to each relay. This avoids the problem of summation of charging currents.

1.6.7 N/N1 Setting

The N1 tap can be used to increase the relay sensitivity to earth faults by lowering settings for these faults without affecting the phase fault settings. This may be particularly desirable for the 15kV scheme where all settings are naturally raised by the increase in energy required to drive the additional isolation transformers. It must be noted that the use of the N1 tap will increase the burden on the CT and therefore should only be used if the CT knee point voltage Vk easily exceeds the minimum requirements stated below, which is often the case with modern CTs. Prior to the introduction of cold rolled iron in CT design, the CT magnetising current effects could cancel out any reduction in setting by increasing the excitation currents required at the higher level of relay burden. Care should be taken when applying the N1 tap to older designs of CT with limited Vk.

The Primary in Zone Capacitance may also limit the use of the N1 tap as loss of charging current may lead to mal-operation at the lower earth fault setting as described above.

1.6.8 In-Zone Tapped Load (Bleed-Off)

The relay is able to tolerate a limited amount of tapped off balanced load within the zone of protection based on the relatively insensitive level of fault setting for balanced 3P differential current. The typical setting is 72% of rated current for 3P faults or differential load current. To allow for switching transients of the tapped load a factor of 3 is advisable. The steady state feeder charging current and CT inaccuracy will also erode the stability margin resulting in a maximum bleed off of 10-20% of rated load current. Zero sequence infeed during out of zone earth faults from any transformer connected at the tapping point must be less than the minimum earth fault sensitivity of the relay at the feeder end. If a 20% tap off consists of a single large transformer, time lag relays may be required between the Solkor trip contact and the CB coil to improve stability by allowing for inrush conditions due transformer excitation.

If the feeder is teed at the substation, with an additional CT fitted to the tee-off, the two CTs should be connected in parallel. To minimise excitation caused by transient spill current the CTs should be connected by the shortest electrical path. Care should be taken in CT specification to ensure that CT mismatch or saturation is not significant for the out of zone fault path where the fault current is not limited by the protected impedance. Fault current passing in and out of the paralleled CTs will fail to cancel if the CTs are mismatched or if saturation occurs to different extents. This current may be higher than the through fault level upon which the CTs are usually sized.

Section 2: Additional Functions

2.1 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)

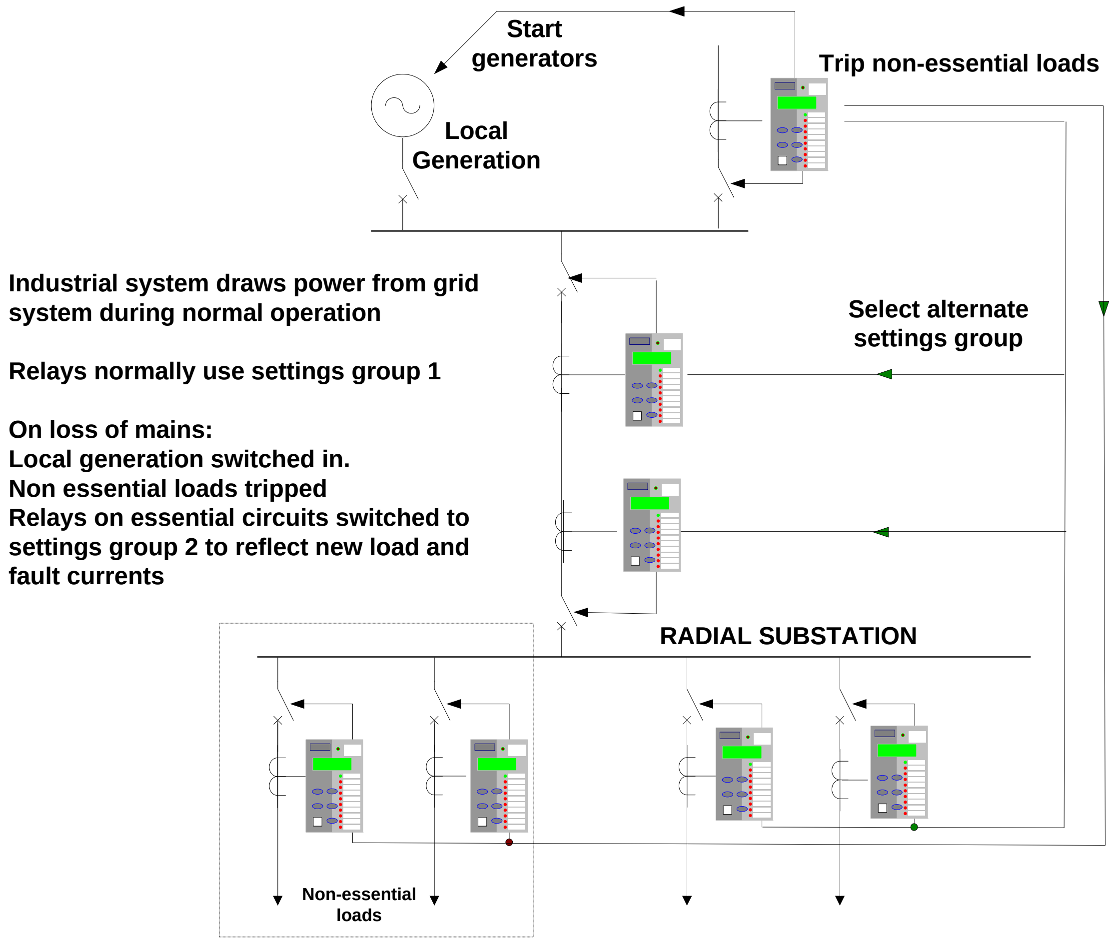


Figure 2.1-1 Example Use of Alternative Settings Groups

The Current Differential protection has fixed settings which cannot be adjusted by settings groups.

2.2 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.

2.2.1 Alarm and Tripping Inputs

A common use of binary inputs is to provide indication of alarm or fault conditions e.g. transformer Buchholz Gas or Buchholz Surge conditions. The Binary Inputs are mapped to LED(s), waveform storage trigger and binary outputs. Note that transformer outputs which require high speed tripping, such as a Buchholz Surge, 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:

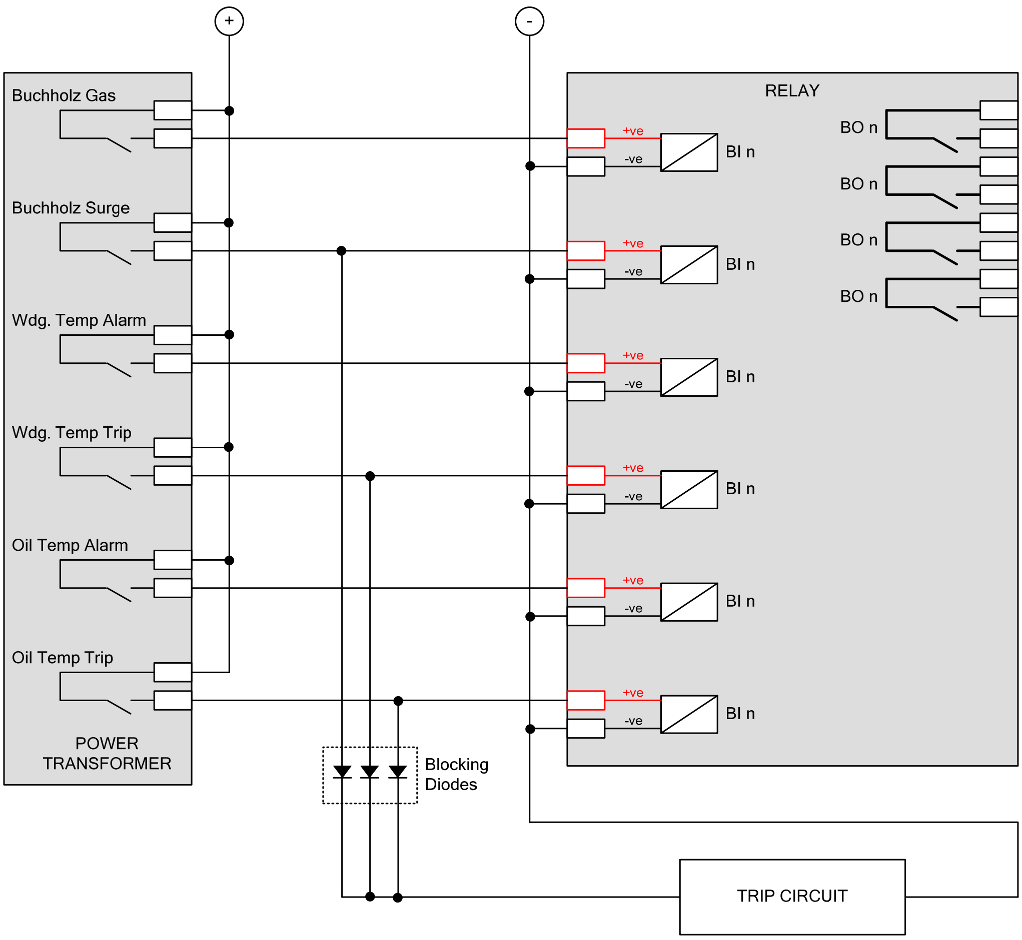


Figure 2.2-1 Example of Transformer Alarm and Trip Wiring

2.2.2 The Effects of Capacitance Current

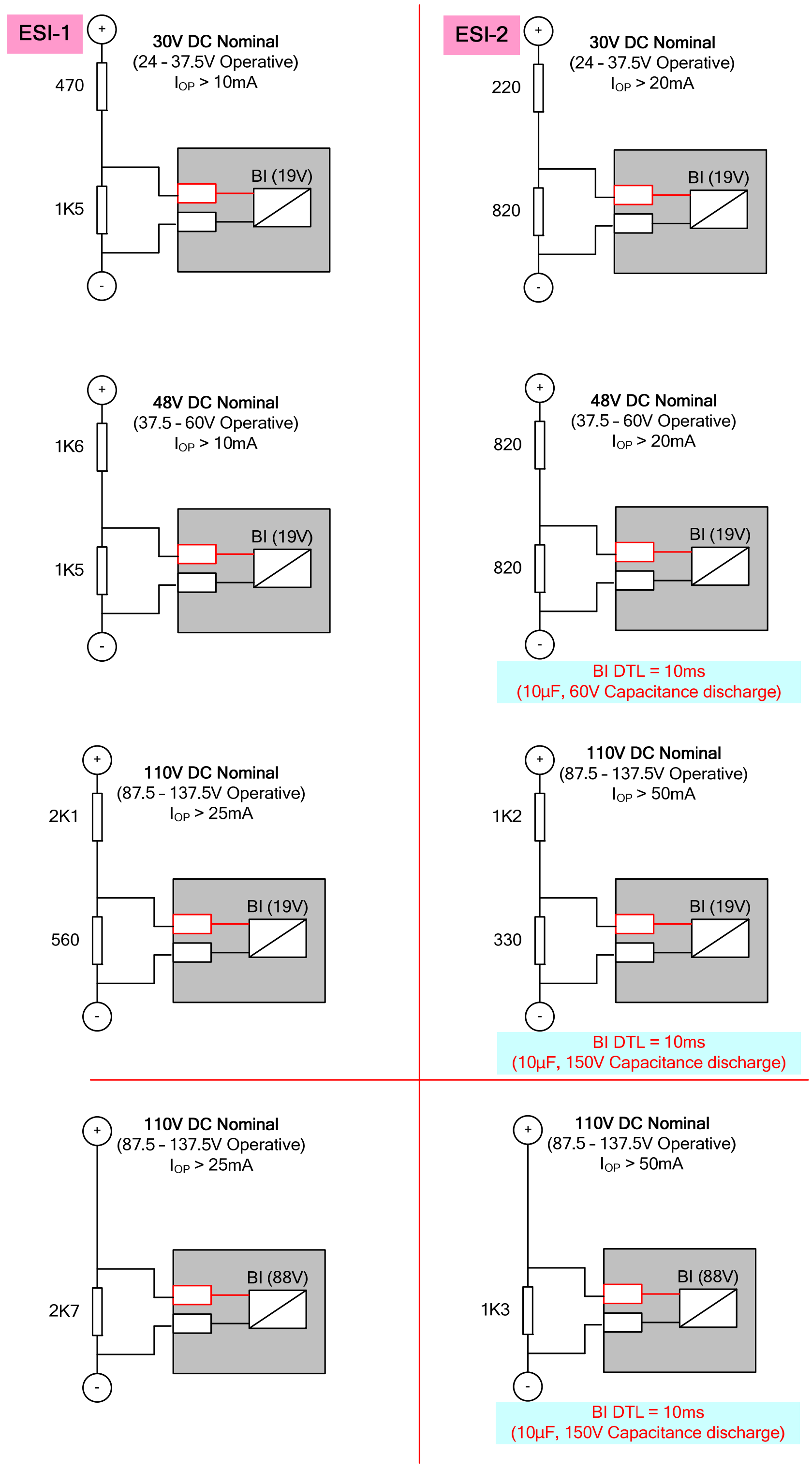
The binary inputs have a low minimum operate current and may be set for instantaneous operation. Consideration should be given to the likelihood of mal-operation due to capacitance current. Capacitance current can flow through the BI for example if an earth fault occurs on the dc circuits associated with the relay. The binary inputs will be less likely to mal-operate if they:

1. Have both the positive and negative switched (double-pole switched).
2. Do not have extensive external wiring associated with them e.g. if the wiring is confined to the relay room.

Where a binary input is both used to influence a control function (e.g. provide a tripping function) and it is considered to be susceptible to mal-operation the external circuitry can be modified to provide immunity to such disturbances, see fig 1.2-2.

2.2.3 AC Rejection

The default pick-up time delay of 20ms provides immunity to ac current e.g. induced from cross site wiring.



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 2.2-2 Binary Input Configurations Providing Compliance with EATS 48-4 Classes ESI 1 and ESI 2

2.3 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.

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.

2.4 LEDS

In the Output Configuration menu LEDs can be 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.

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.

Section 3: Protection Functions

3.1 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.

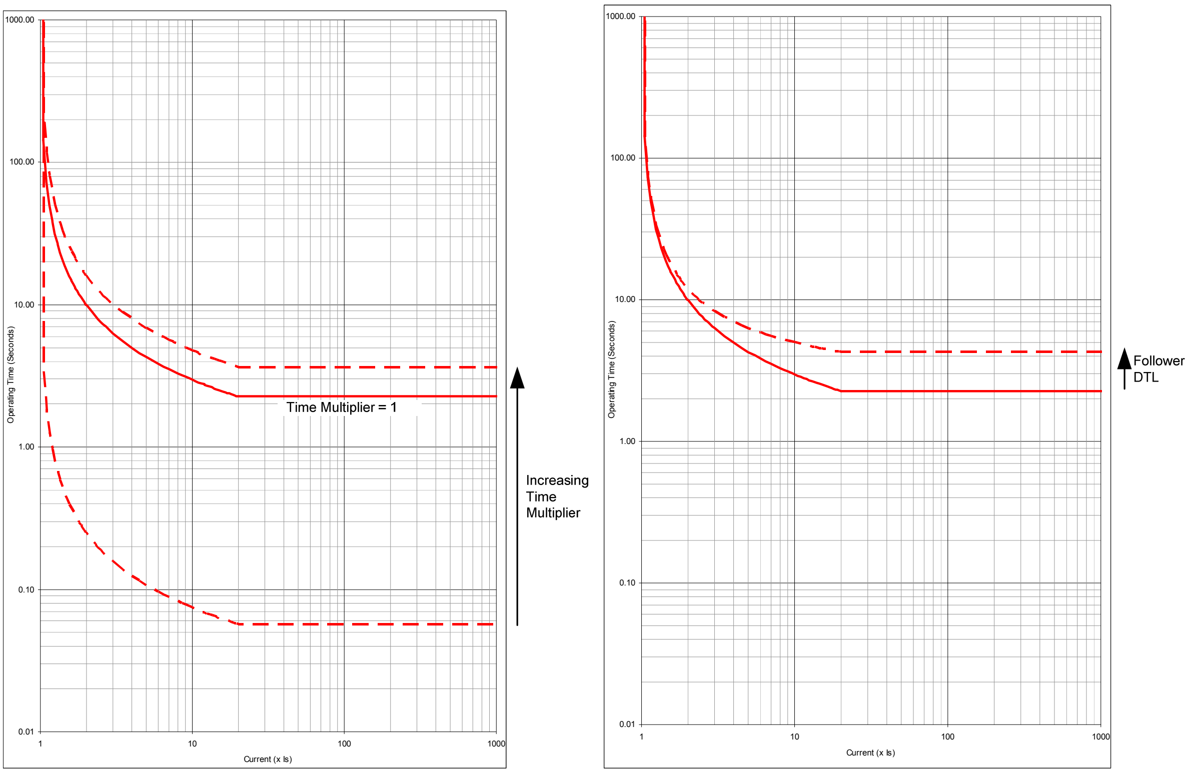


Figure 3.1-1 IEC NI Curve with Time Multiplier and Follower DTL Applied

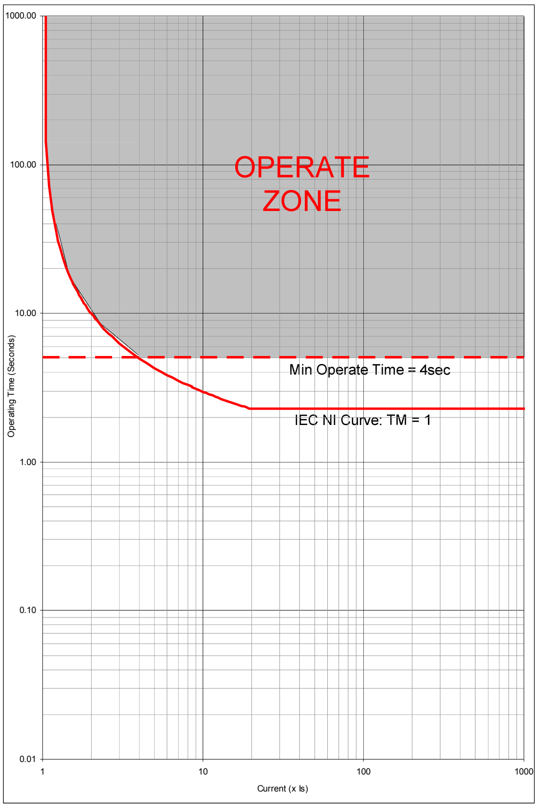


Figure 3.1-2 IEC NI Curve with Minimum Operate Time Setting Applied

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.

3.1.1 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

Table 3-1 Application of IDMTL Characteristics

3.1.2 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 occurrence 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.

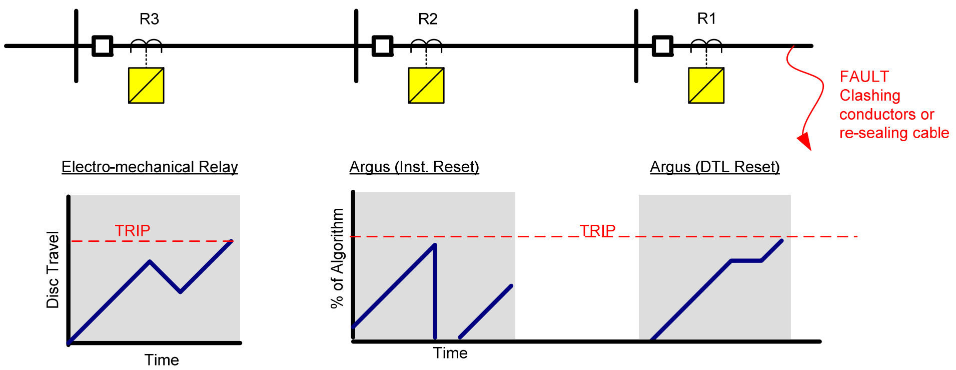


Figure 3.1-3 Reset Delay

3.2 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 (VDO) 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.

3.3 Cold Load Settings (51c)

Once a Circuit-Breaker has been open for a period of time, 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.

3.4 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.

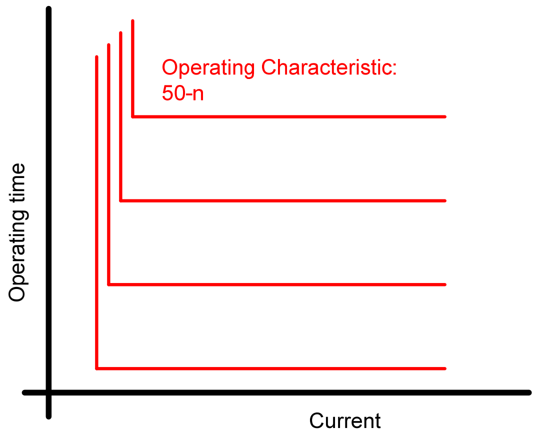


Figure 3.4-1 General Form of DTL Operate Characteristic

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 minimum 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.

3.5 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.

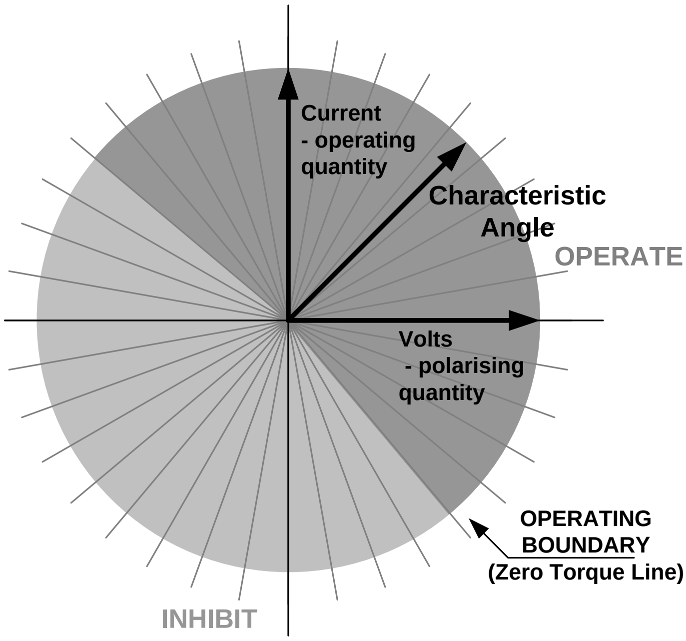


Figure 3.5-1 Directional Characteristics

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 2.6-1 shows the most likely fault angle for phase faults on Overhead Line and Cable circuits.

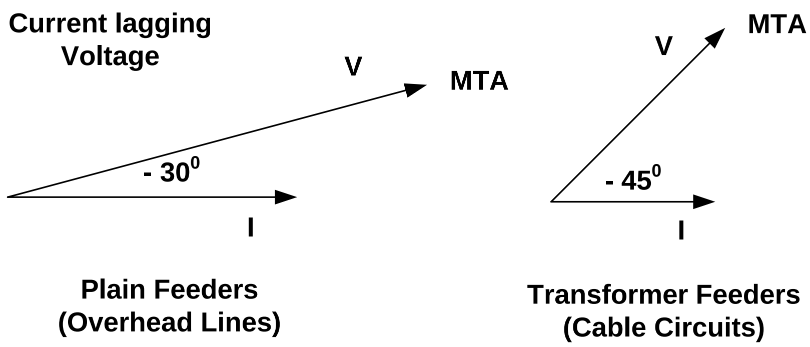


Figure 3.5-2 Phase Fault Angles

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 the relays may be programmed with forward, reverse and non-directional elements simultaneously when required by the protection scheme.

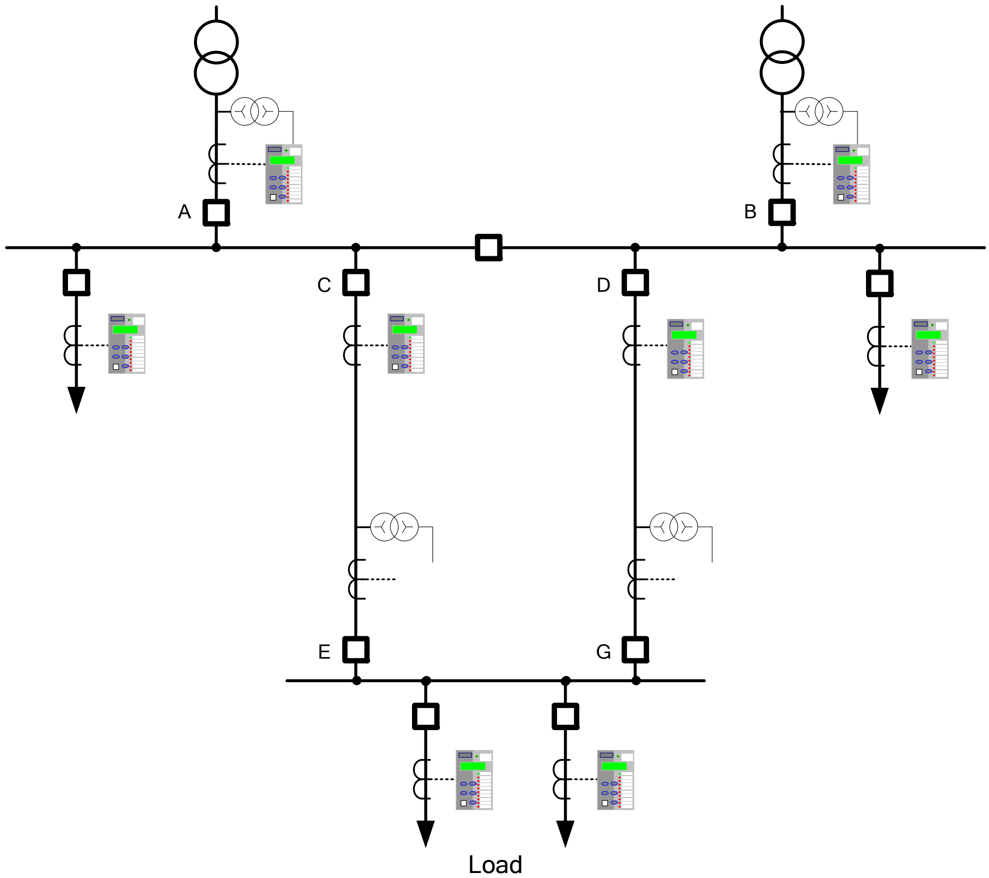


Figure 3.5-3 Application of Directional Overcurrent Protection

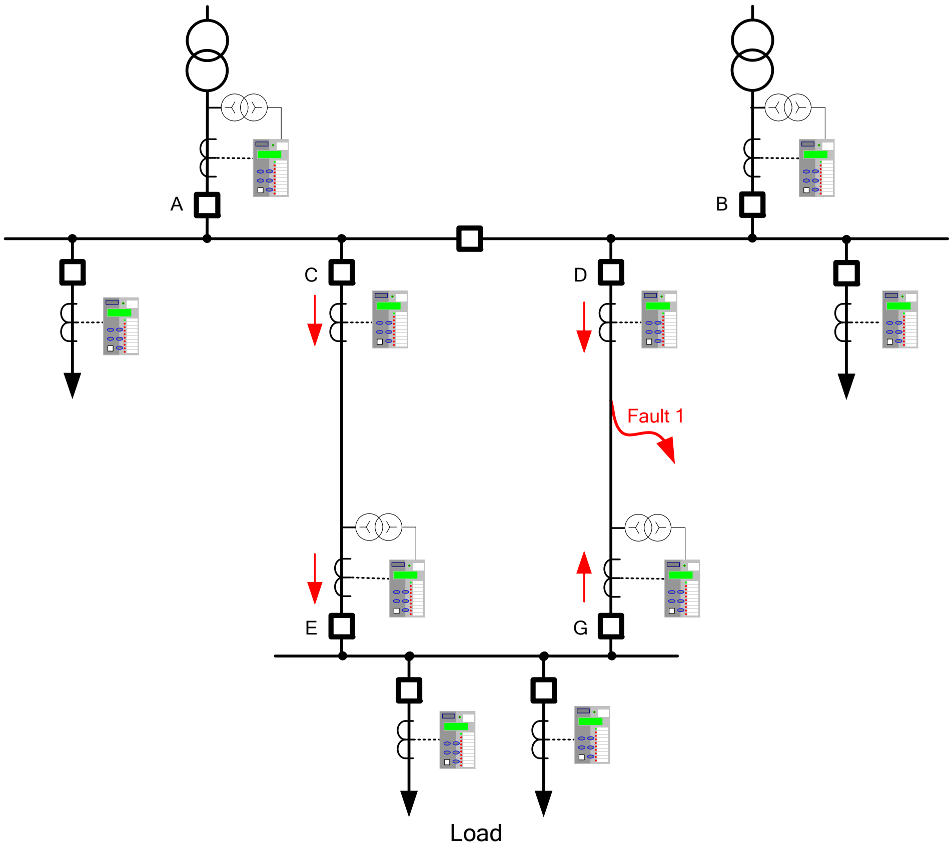


Figure 3.5-4 Feeder Fault on Interconnected Network

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.

3.5.1 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 unbalanced 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.

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

The directional earth-fault elements, either measured directly or derived 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)				
O^0	-15^0	-45^0	-65^0	-90^0
← Resistive Neutral			Reactive Neutral →	

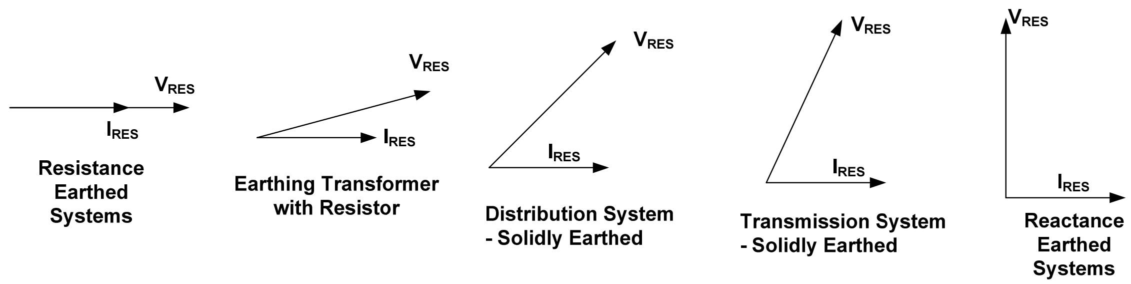


Figure 3.6-1 Earth Fault Angles

3.7 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 relay 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.

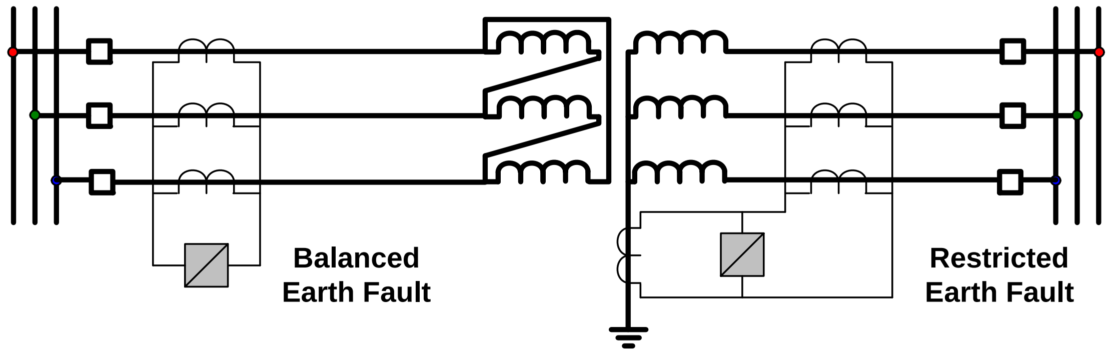


Figure 3.7-1 Balanced and Restricted Earth-fault protection of Transformers

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 shown below.

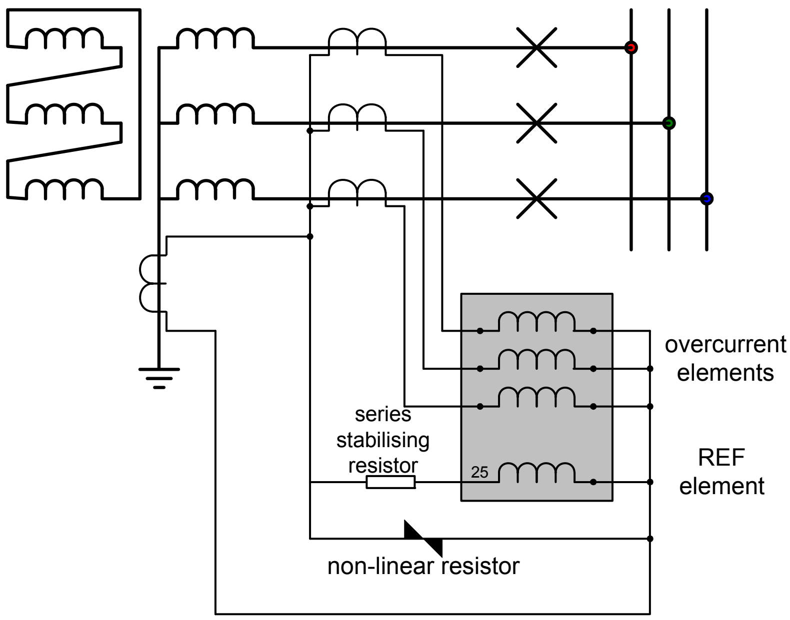


Figure 3.7-2 Composite Overcurrent and Restricted Earth-fault Protection

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.

3.8 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.

3.9 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.

3.10 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.

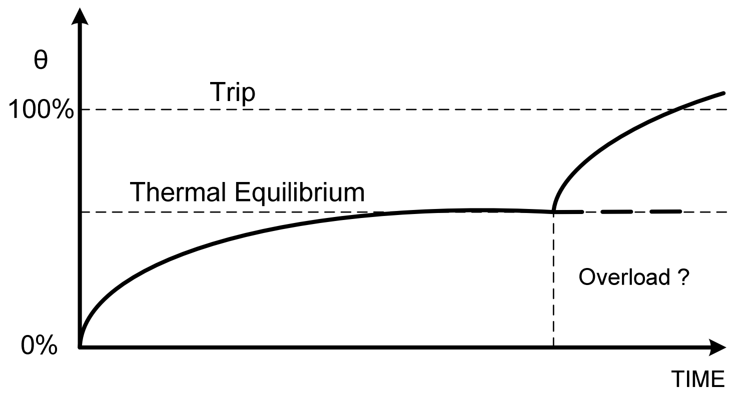


Figure 3.10-1 Thermal Overload Heating and Cooling Characteristic

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.

3.11 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.

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 undervoltage 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 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.

3.12 Neutral Overvoltage (59N)

Neutral Voltage Displacement (NVD) 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.

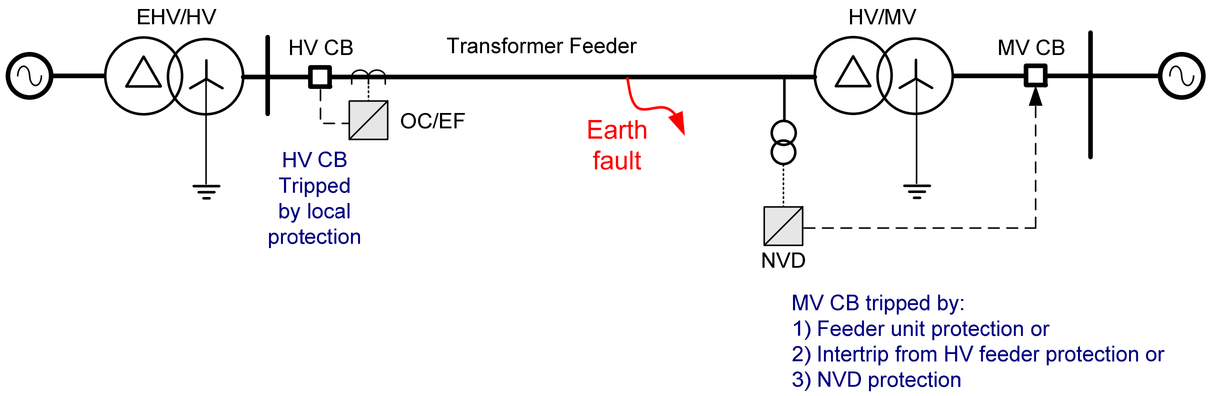


Figure 3.12-1 NVD Application

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.

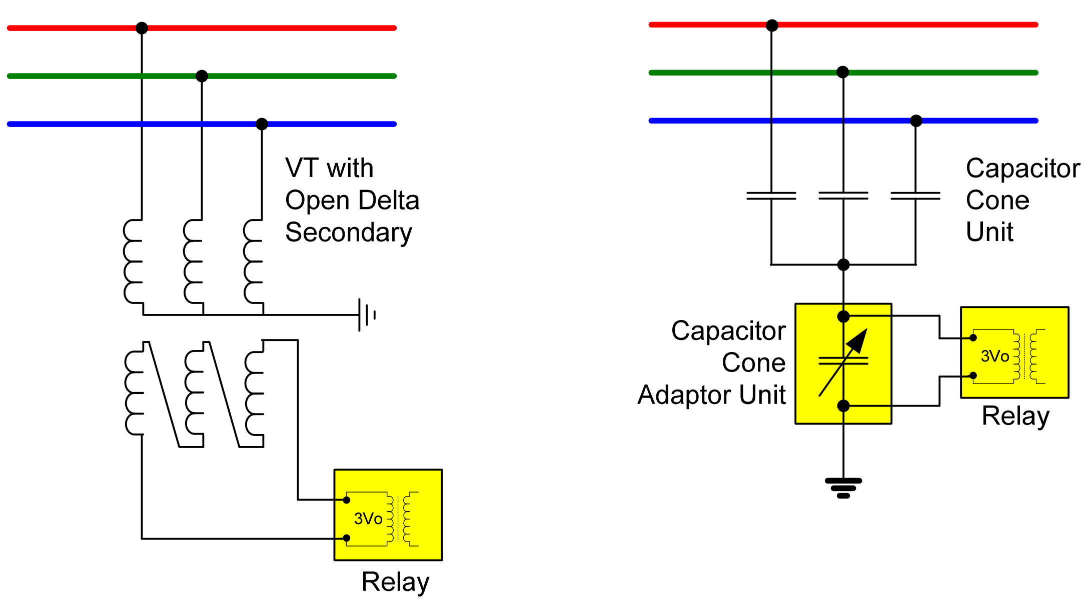


Figure 3.12-2 NVD Protection Connections

3.12.1 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.

3.12.2 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.

3.13 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.

Section 4: CT Requirements

4.1 CT Requirements for Current Differential Protection

The main requisite is that the saturation voltage of the current transformers should not be less than that given by the formula:

$$V_k = \frac{50}{I_n} + \frac{I_F}{N}\left(R_{CT} + 2R_L\right)$$

Where I_n = Rated current of Solkor Rf relay.

I_F = Primary current under maximum steady state THROUGH FAULT conditions.

N = Current Transformer ratio.

R_{CT} = Secondary resistance of the current transformer

R_L = Lead resistance between the current transformers and the Solkor R/Rf, per phase.

For the above purpose the saturation voltage i.e. the knee point of the magnetising curve, may be taken as that point on the curve at which a 10% increase in output voltage requires 50% increase in magnetising current.

To ensure good balance of the protection the current transformers at the two ends should have identical turns ratios. Close balance of the ratio is provided by current transformers to IEC60044: pt1, class px, whose ratio error is limited to ±0.25% and these CTs are recommended to meet the above requirements.

It is recommended that no other burdens should be included in the current transformer circuit, but where this cannot be avoided the additional burden should be added to those listed when determining the current transformer output voltage required.

In addition to the above, the secondary magnetising currents of the current transformers at different ends of the feeder should normally not differ by more than I_N/20 amperes for output voltages up to 50/I_N volts where I_N = rated current of Solkor Rf relay. This criteria is applied to quantify matching of the transient response of the two CTs so that relay operations do not occur due to differing responses of the CTs to normal load switching or the incidence and clearance of out of zone faults. This condition is usually easily satisfied by modern CTs of similar size since the magnetising current is usually a lower value. Care should be taken when applying a new CT to be paired with existing CT and also when interposing CTs are required to match CT ratios.

The fault current used for the above calculation should be the THROUGH FAULT level. This condition must be considered to ensure that the relay will not be caused to operate for through faults due to secondary differential current being created by the failure of the CT to measure correctly due to core saturation. During a high level internal fault the relay will operate before the saturation effect becomes significant. The THROUGH fault level is often not readily available and may be significantly different to the source Busbar fault level which is commonly quoted incorrectly based on switchgear rating rather than on the actual current level which is limited by system impedances. The remote end fault level will be distorted by any parallel infeed or backfeed and is only equivalent to the through fault level for truly radial systems.

The following example shows a simple through fault current estimate based on Busbar levels and commonly available data.

4.1.1 Example Fault Current Estimation

33kV Overhead line

10km long

X_L = 0.28978 ohms/km R_L= 0.07765 ohms/km (Primary)

CT ratio = 400:1

R_{CT} = 2 ohms

CT wiring resistance, R_L, 30m long 7/0.67mm 2.5mm sq. at 7.4 ohms/km = 0.22 ohms

VT ratio 33000:110V

Maximum X/R ratio at source busbar = 20

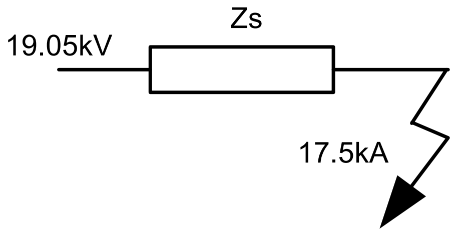
Maximum 3P fault level at busbar = 1000MVA

Consider 3P fault level based on maximum busbar levels.

V_{Ph} = 33000/√3 = 19.05kV

Fault level per phase = 1000/3 = 333MVA

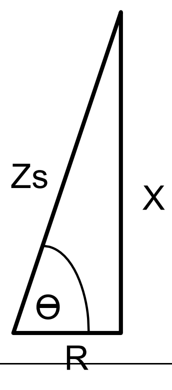
$$I_F = \frac{333x10^6}{19.05x10^3} = 17.5kA$$



$$\boxed{Z_S = \frac{19.05x10^3}{17.5x10^3} = 1.089\Omega}$$

Also, since X/R at the busbar = 20,

We can evaluate the source impedance:



$$\theta = Tan^{-1}\left(\frac{X}{R}\right)$$

$$\theta = 87^{\circ}$$

$R_S = Z_S \cos\theta = 00544\Omega$ & $X_S = Z_S \sin\theta = 1.0876\Omega$ (Primary)

R_L= 0.07765 ohms/km (Primary)

R_L = 10 x 0.07765 = 0.7765Ω (Primary)

X_L = 0.28978 ohms/km

X_L= 10 x 0.28978 = j2.8978Ω (Primary)

Total impedance for a through fault at the remote busbar =

Z_S + Z_L = (R_S + R_L) + (X_S + X_L)

(0.0544 + 0.7765) + j(1.0876 +2.8978)

Z_F = 0.8309 + j3.9854 ohms

$$|Z| = \sqrt{R^2 + X^2}$$

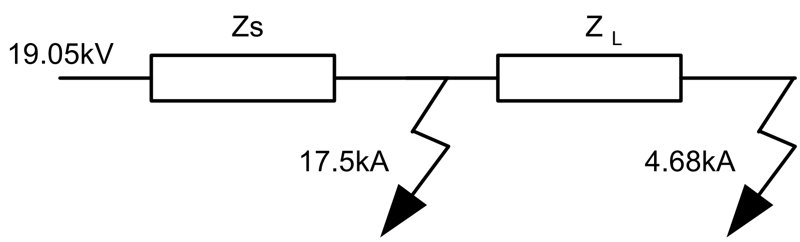
$$|Z| = \sqrt{0.8309^2 + 3.9854^2}$$

Z_F = 4.071 ohms

Through Fault Current =

$$I_F = \frac{19.05x10^3}{4.071} = 4.68kA$$

Through fault current = 4.68kA compared to 17.5kA Busbar fault current due to the effect of the line impedance.



4.2 CT Requirements for Overcurrent and Earth Fault Protection

4.2.1 Overcurrent Protection CTs

The requirements for Current Differential protection are generally more onerous than for overcurrent protection.

If the internal fault level is much greater than the through fault level, the saturation during internal faults must be considered.

For idmtl 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.

Knee point voltage does 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, by increasing the kneepoint voltage requirement.

4.2.2 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.

4.3 CT Requirements for High Impedance Restricted Earth Fault Protection

For high impedance REF it is recommended that:

Low reactance CTs to IEC Class PX are used, this allows a sensitive current settin to be applied.

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

The knee point voltage of the CTs must be greater than 2 x 64H setting voltage Vs.

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

A full explanation of how to specify CTs for use with REF protection, and set REF relays is available on our website: www.siemens.com/energy.

Section 5: Control Functions

5.1 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.

If autoreclose is required to execute for Solkor Current Differential trips, the Binary Input that is connected to the Current Differential module should be mapped as *79 Ext Trip* in the *Input Matrix*.

The function supports up to 4 ARC sequences. That is, 4 x Trip / Recloses followed by a Trip & Lockout. A lockout condition prevents any further automatic attempts 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 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.
- The next 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.

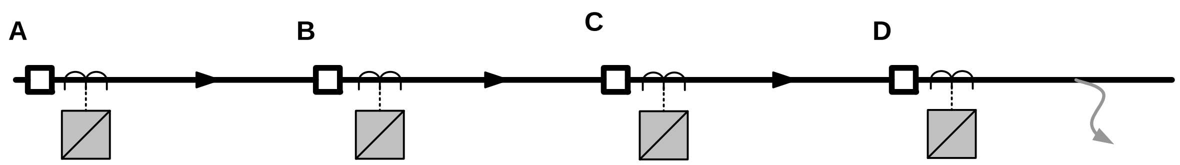


Figure 5.1-1 Sequence Co-ordination

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.

5.1.1 Auto-Reclose Example 1

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

Proposed settings include:

CONTROL & LOGIC > AUTORECLOSE PROT'N:

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

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

***79 E/F Delayed Trips*: 51N-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 > E/F SHOTS

***79 E/F Prot'n Trip 1* : Delayed**

***79 E/F Prot'n Trip 2* : Delayed**

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

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

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

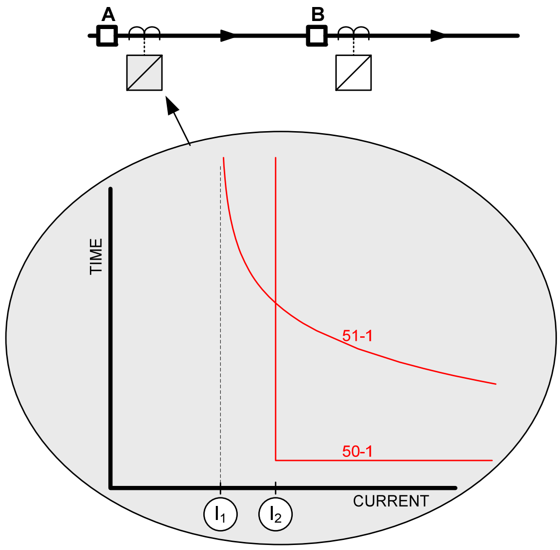


Figure 5.1-2 Example of Logic Application

Requirement: The relay at location 'A' 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**

5.2 Quick Logic Applications

5.2.1 Auto-Changeover Scheme Example

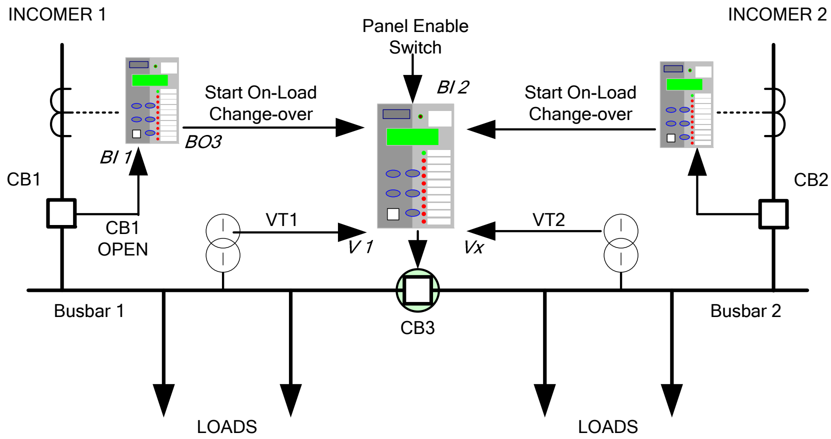


Figure 5.2-1 Example Use of Quick Logic

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):

Incomer 1 Relay is Configured:

CB1 Open auxiliary switch wired to BI 1

Trip output to CB1 = BO 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 (Binary Output 3) 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.

CB3 Relay is Configured:

Panel switch (ON-Load Change-over Enabled) wired to BI2

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 6: Supervision Functions

6.1 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. For CB trips where the fault is not current related an additional input is provided (50BF Mech Trip) which monitors the CB closed input and provides an output if the circuit breaker has not opened before the timers expire.

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).

If the CB is faulty and unable to open, a faulty contact can be wired to the CB faulty input of the relay and if a trip occurs while this input is raised the CB fail delay timers may be by-passed to allow back tripping to occur without delay.

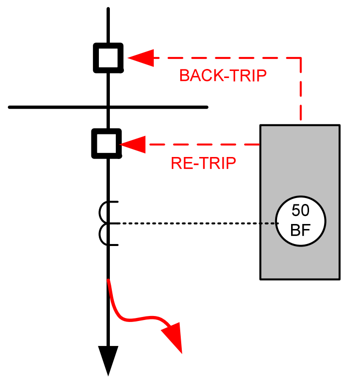


Figure 6.1-1 Circuit Breaker Fail

6.1.1 Settings Guidelines

50BF Setting

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

50BF Setting-I4

The EF or SEF current setting must be set below the minimum protection setting current.

50BF Ext Trig

Any binary input can be mapped to this input to trigger the circuit breaker fail function. Note current must be above setting for the function to operate.

50BF Mech Trip

Any binary input can be mapped to this input to trigger the circuit breaker fail function. Note for the function to operate the circuit breaker closed input is used to detect a failure, not the current.

50BF CB Faulty

Any binary input can be mapped to this input, if it is energised when a trip initiation is received an output will be given immediately (the timers are by passed).

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

The time delays run concurrently within the relay. The time delay 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
Reset Time		20ms
CB Tripping time		50ms
Safety Margin		40ms
Overall First Stage CBF Time Delay	120ms	

Second Stage (Back Trip)

First CBF Time Delay		120ms
Trip Relay operate time		10ms
CB Tripping time		50ms
Reset Time of measuring element		20ms
Margin		60ms
Overall Second Stage CBF Time Delay	260ms	

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.

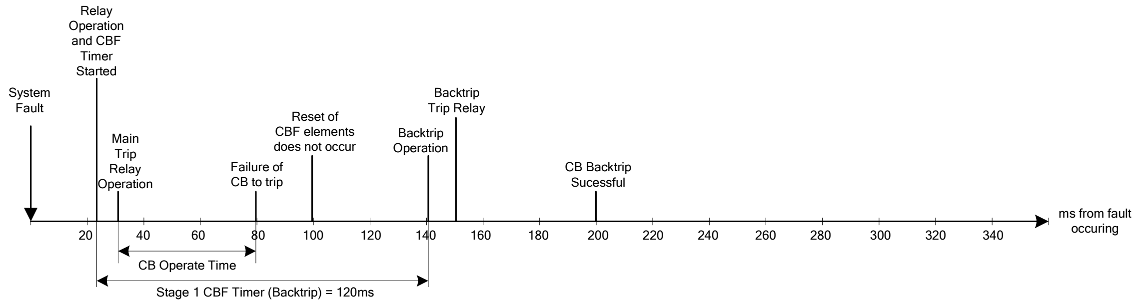


Figure 6.1-2 Single Stage Circuit Breaker Fail Timing

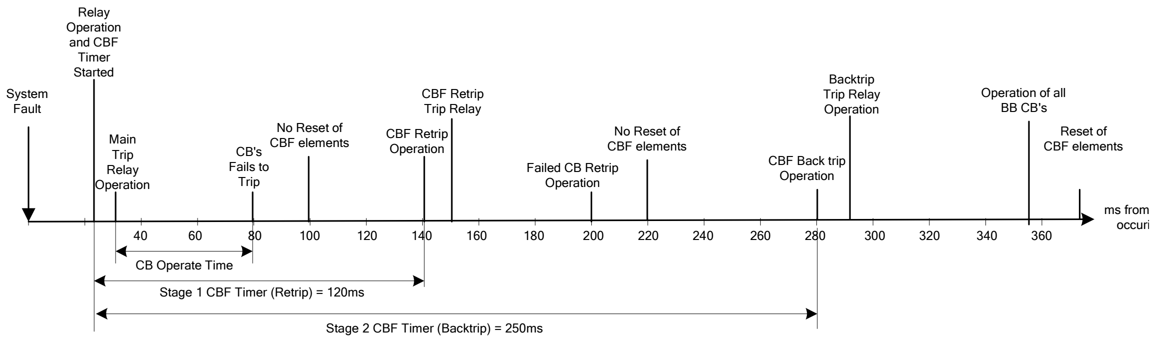


Figure 6.1-3 Two Stage Circuit Breaker Fail Timing

6.2 Current Transformer Supervision

When a CT fails, the current levels seen by the protection become unbalanced, however this condition would also occur during a system fault. Depending upon the relay model different methods are used to determine the condition, depending upon the measured quantities available.

Current Transformer Supervision (60CTS – 7PG2113/5)

Following a CT Failure, if one or two of the three phases falls below the CT supervision setting the element will operate

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.

Current Transformer Supervision (60CTS – 7PG2114/6)

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 shown in the accompanying table.

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

Table 6-1 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.

6.3 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 6-2 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 6-3 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.

6.4 Trip/Close Circuit Supervision (74T/CCS)

Binary Inputs may be used to monitor the integrity of the CB trip and close circuit wiring. A small current flows through the B.I. and the circuit. This current operates the B.I. confirming the integrity of the auxiliary supply, CB 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 or 74CCS 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 or 74CCS-n.

6.4.1 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)

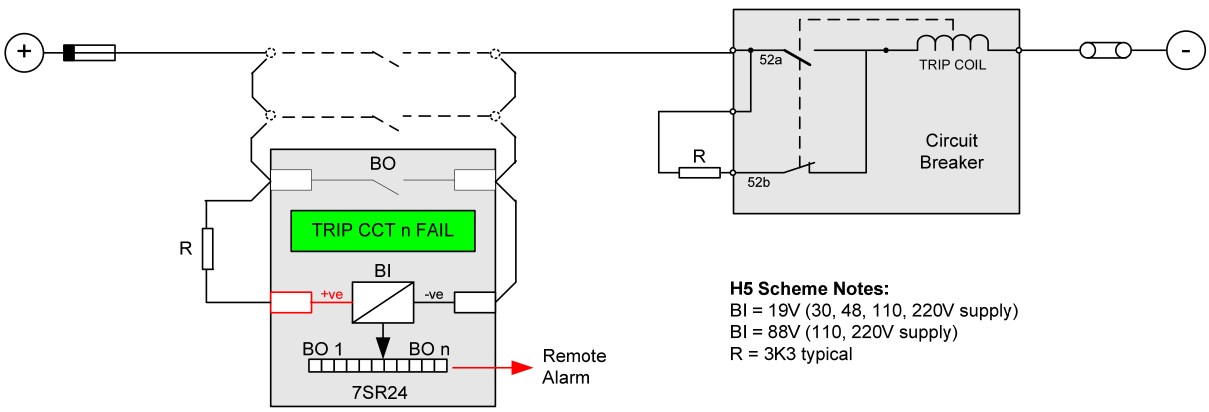


Figure 6.4-1 Trip Circuit Supervision Scheme 1 (H5)

Scheme 1 provides full Trip 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)

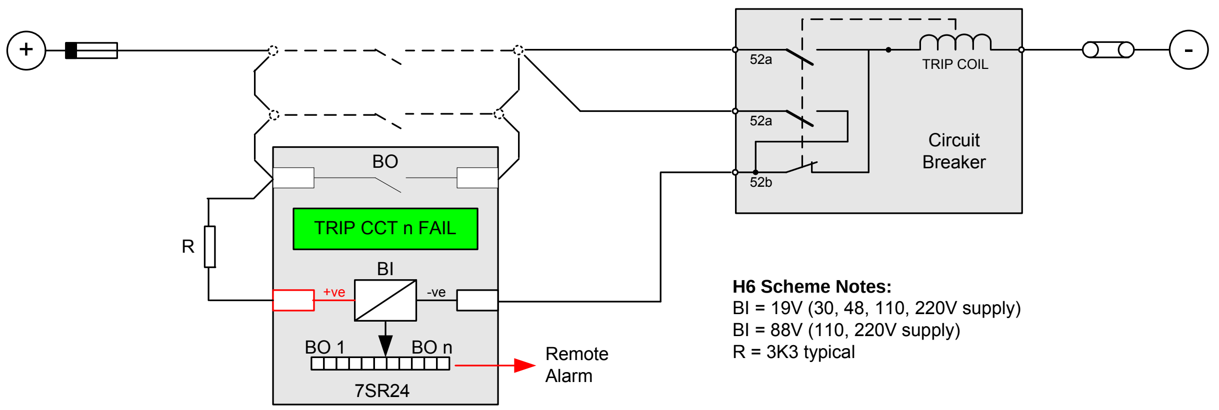


Figure 6.4-2 Trip Circuit Supervision Scheme 2 (H6)

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)

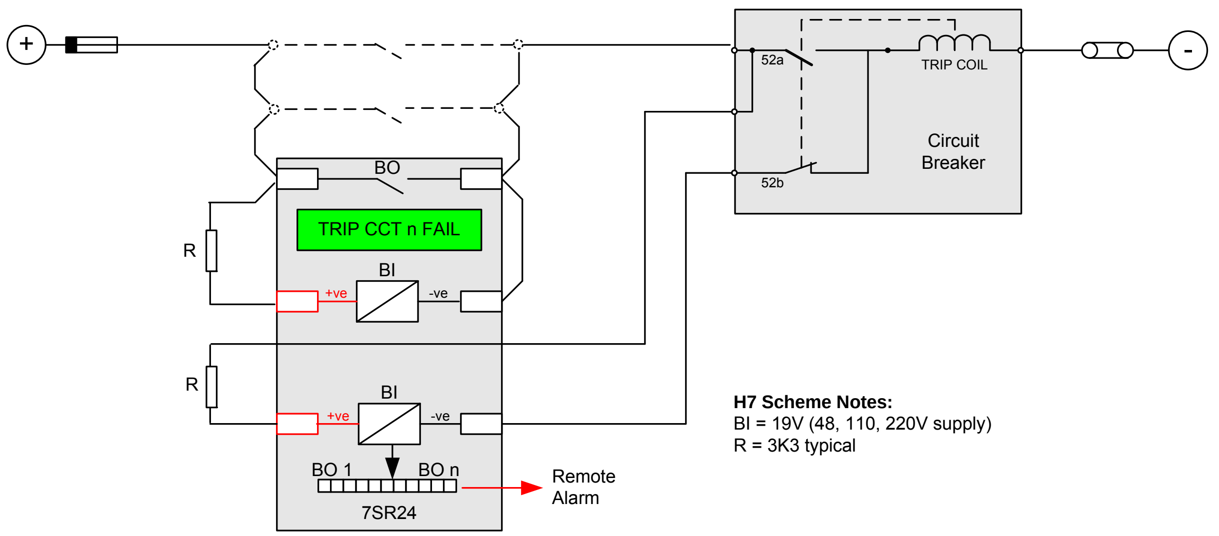


Figure 6.4-3 Trip Circuit Supervision Scheme 3 (H7)

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

6.4.2 Close Circuit Supervision Connections

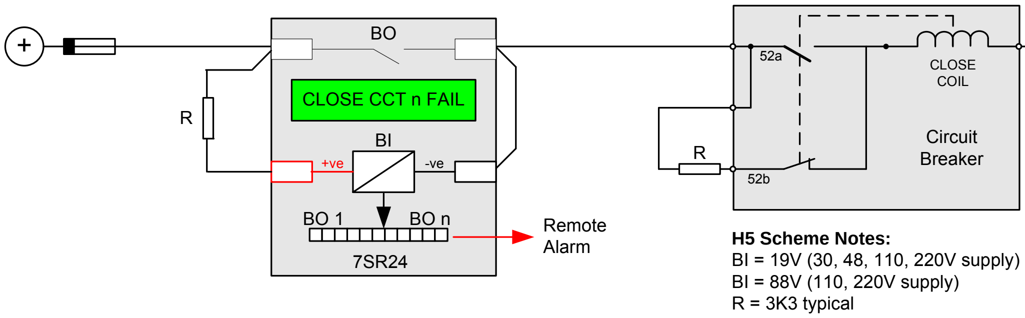


Figure 6.4-4 Close Circuit Supervision Scheme

Close circuit supervision with the circuit breaker Open or Closed.

6.5 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 6-4 Magnetic Inrush Bias

6.6 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.

6.7 Circuit-Breaker Maintenance

The Relay provides Total, Delta and Frequent CB Operation Counters along with 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 or manufacturers data sheets are used for setting these alarm levels. The relay instrumentation provides the current values of these counters.