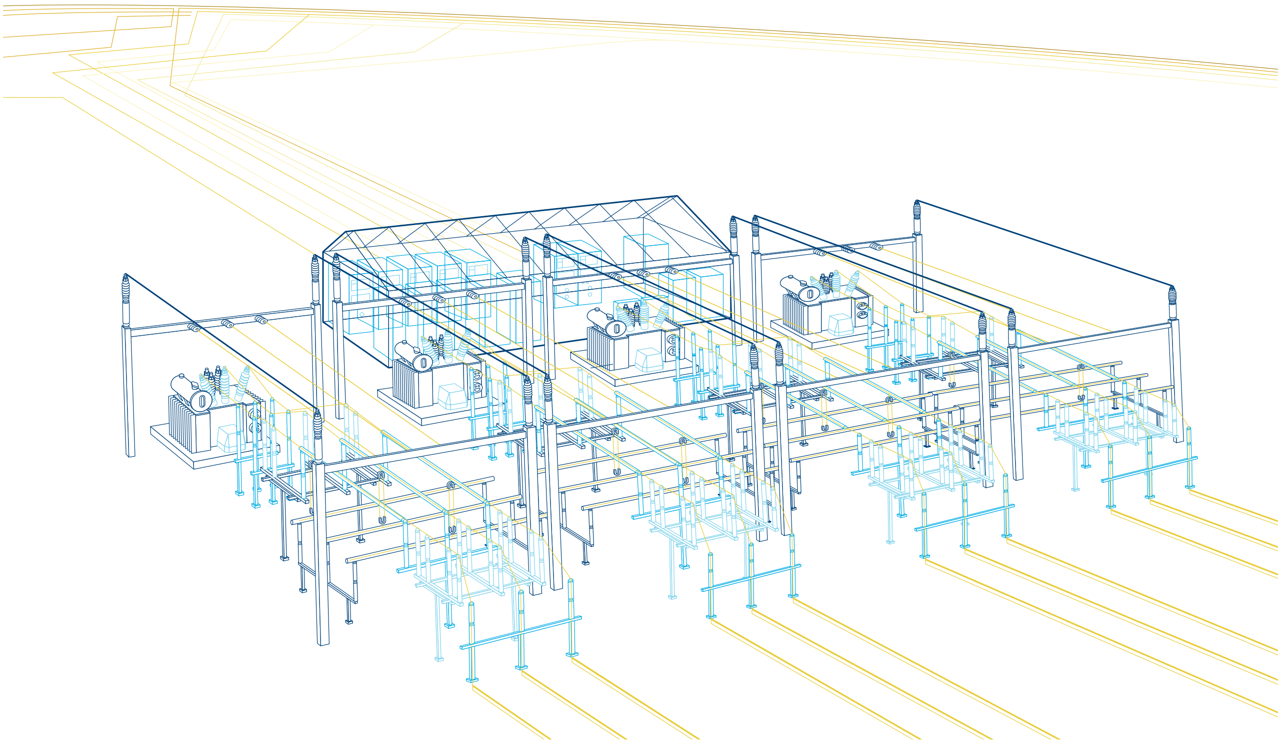
Distribution Automation Handbook

Section 8.2 Relay Coordination



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8.2.1 Introduction

The selected protection principle affects the operating speed of the protection, which has a significant impact on the harm caused by short circuits. The faster the protection operates, the smaller the resulting hazards, damage and the thermal stress will be. Further, the duration of the voltage dip caused by the short circuit fault will be shorter, the faster the protection operates. Thus, the disadvantage to other parts of the network due to undervoltage will be reduced to a minimum. The fast operation of the protection also reduces post-fault load peaks which, in combination with the voltage dip, increase the risk of the disturbance spreading into healthy parts of the network. In transmission networks, any increase of the operation speed of the protection will allow the loading of the lines to be increased without increasing the risk of losing the network stability.

Good and reliable selectivity of the protection is essential in order to limit the supply interruption to the smallest area possible and to give a clear indication of the faulted part of the network. This makes it possible to direct the corrective action to the faulty part of the network and the supply to be restored as rapidly as possible.

Thus, attention must be paid to the operating speed of the protection, which can be affected by a proper selection of the applied protection principle. Selective short-circuit protection can be achieved in different ways, such as:

- Time-graded protection
- Time- and current-graded protection
- Time- and direction-graded protection
- Current- and impedance-graded protection
- Interlocking protection
- Differential protection

8.2.2 Time-graded Protection

A straightforward way of obtaining selective protection is to use *time grading*. The principle is to grade the operating times of the relays in such a way that the relay closest to the fault spot operates first. Time-graded protection is implemented using overcurrent relays with either definite time characteristic or inverse time characteristic. The operating time of definite time relays does not depend on the magnitude of the fault current, while the operating time of inverse time relays is shorter the higher the fault current magnitude is. The time-graded protection is best suited for radial networks.

The principle of inverse time protection is especially suited for radial networks where the variations of short-circuit power due to changes in network configuration are small or where the short-circuit current magnitude at the beginning and end of the feeder differs considerably. In these cases, the use of inverse time relays in favor of definite time relays can usually speed up the operating time of the protection at high fault current magnitudes. Time grading with fuses is also easier to obtain with inverse time relays. Considering the above arguments and also taking into account, for example the short-circuit current withstand capacity of the network components, applying inverse time relays for the network short-circuit protection may be justified.

The IEC 60255-151 and BS 142 standards define four characteristic time-current curve sets for inverse time relays:

- Normal inverse
- Long-time inverse
- Very inverse
- Extremely inverse

For inverse time relays the operating time (s) can be calculated from the equation:

$$t = \frac{k \cdot \beta}{\left(\frac{I}{I>}\right)^{\alpha} - 1} \qquad \textbf{(8.2.1)}$$

where

k	is an adjustable time multiplier
I	is the measured phase current value
$I>$	is the set start (pickup) current value
α, β	are curve set-related parameters

According to the standards, the relay should start once the energizing current exceeds 1.3 times the set start current when the normal, very or extremely inverse time characteristic is used. When the long-time inverse characteristic is used the relay should start when the energizing current exceeds 1.1 times the set start current.

The parameters α and β define the steepness of the time-current curves as follows:

Table 8.2.1: Curve set related parameters

Type of characteristic	α	β
Normal inverse	0.02	0.14
Very inverse	1.0	13.5
Extremely inverse	2.0	80.0
Long-time inverse	1.0	120.0

Figure 8.2.1 shows a time-graded protection arrangement in a radial network. In the example network, *three-stage protection* is implemented. For the *low-set stage* (3I>), either inverse time or definite time characteristic can be given. The *high-set* and the *instantaneous stage* (3I>> and 3I>>>) have definite time cha-

racteristic and their purpose is to accelerate the operation of the protection under heavy fault current conditions. A multiple-stage protection is often required to meet with the sensitivity and operating speed requirements and to achieve a good and reliable grading of the protection, see Figure 8.2.1.

Studying and planning of time-selective protection schemes is most conveniently carried out using *selectivity diagrams*. The selectivity diagram is a set of specific time/current curves which shows all the *time/current curves*, that is, the *operating characteristics* of the relays of the concerned *chain of protection relays*. The chain of relays in the example of Figure 8.2.1 includes two relays. The selectivity diagram also includes additional information needed for the planning and operation of the protection, such as the lowest and highest fault current levels in the relaying points, maximum load current, nominal currents and short-circuit current withstand capacity of network components and the maximum limit values of possible switching inrush currents and start currents.

The selectivity diagram of Figure 8.2.1 shows that should a fault arise, for example, in the far end of the feeder (outgoing feeder 1) protected by relay 1, the fault current magnitude will be on the level indicated by ⑧. This fault causes both the relay 1 and relay 2 to start (outgoing feeder 1). Thus, the concerned feeder belongs to the protection area of the relay 1 and relay 2, providing an inherent backup protection for the feeder. Should relay 1 or its circuit breaker fail to operate, relay 2 will be allowed to operate.

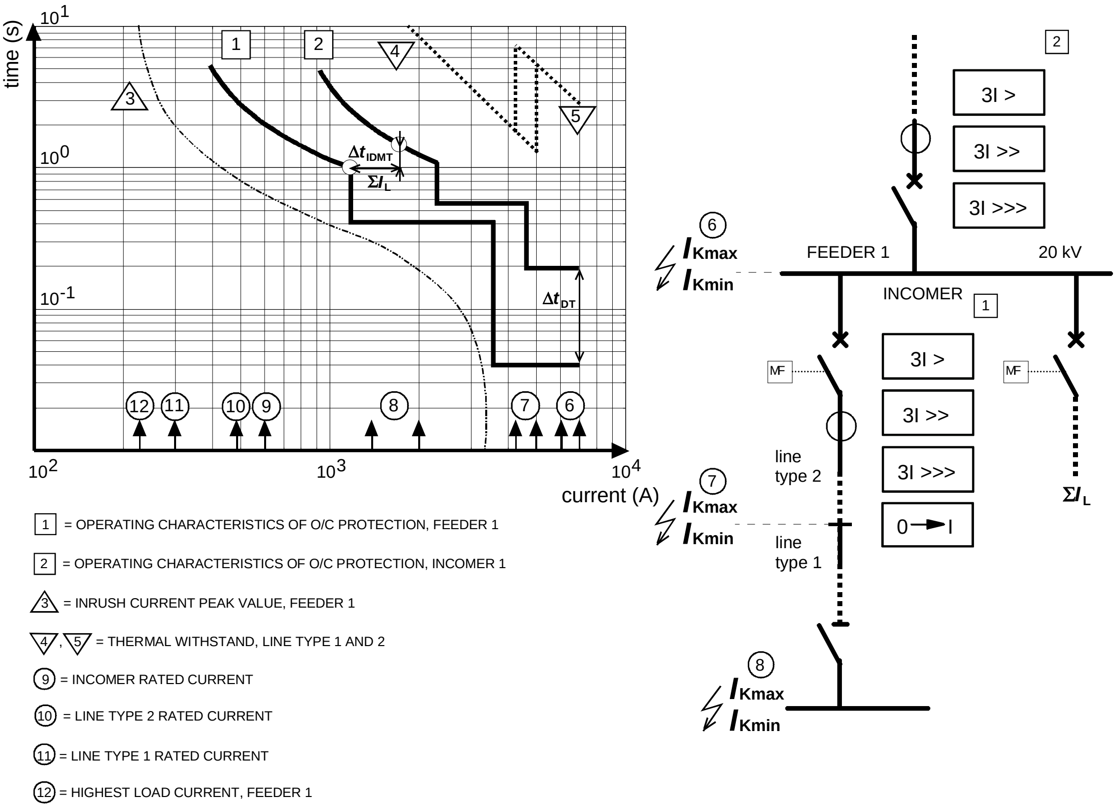


Figure 8.2.1: Overcurrent protection of radial network and the corresponding selectivity diagram

The selection of the proper *grading time* is of essential importance for the selectivity of the protection. The grading time is the time difference between two consecutive *protection stages*. In heavy fault current conditions, the relay operating time must not be unnecessarily prolonged and, on the other hand, a satisfactory margin must be maintained to secure the selectivity. When inverse time relays are used instead of definite time relays, longer grading times must generally be used, because, among other things, the effect of the inaccuracy of the current measurement on the operating time must be observed.

In the example of Figure 8.2.1, the grading times have been defined separately for each stage. The grading time between the inverse time stages have been denoted Δt_{IDMT} and, correspondingly, the grading time between definite time stages has been denoted Δt_{DT}. When defining the grading time, it must be noted that at lower fault current levels the prevailing load currents ΣI_L of the healthy feeders during the fault must be taken into account to a certain degree. These currents are summed, for example, into the current measured by relay 2 when a fault appears on feeder 1.

When numerical relays are used, the required grading times can be calculated from Equations (8.2.2) and (8.2.3). Figure 8.2.2 shows how the grading times and the factors affecting them are formed. For definite time relays, the grading time Δt_{DT} is obtained from Equation (8.2.2).

$$\Delta t_{DT} = 2 \cdot t_E + t_R + t_{CB} + t_M \qquad \textbf{(8.2.2)}$$

where

t_E	is the tolerance of the relay operating time
t_{CB}	is the circuit breaker operating time
t_R	is the relay retardation time
t_M	is the safety margin

The safety margin takes into account the possible delay of the relay operation due to CT-saturation caused by the DC-component of the fault current. The length of the possible additional delay thus occurring is affected by the fault type, fault current magnitude and the ratio between the CT-accuracy limit factor and the set current value. In theory, the delay can even be as long as the time constant of the DC-component, should the fault current just slightly exceed the set value and should the set value have been chosen just slightly below the corresponding CT-accuracy limit factor. In practice, however, the CTs of the consecutive relays of the protection chain will saturate within a certain fault current range, which means that the operation of the relays is about equally delayed. For this reason, a safety margin of about the length of the fundamental frequency cycle is enough.

If, however, relatively big differences in the accuracy limit factors of successive CTs in the protection chain exist, it might be justifiable to increase the safety margin in relation to the time constant of the DC-component. The safety margin is also to be increased if auxiliary relays are used in the trip circuit of the circuit breaker.

The retardation time is the time period just before the elapsing of the operation delay timer. If the fault disappears before the starting of the retardation time, the protection relay that has been started by the fault is still able to cancel its tripping command. If the fault disappears during the retardation time just before the elapsing of the operation delay timer, the tripping command will be initiated.

The grading time Δt_{IDMT} for protection schemes based on inverse time relays is obtained from Equation (8.2.3):

$$\Delta t_{IDMT} = t_1 \cdot \left(\frac{1 + E_1/100}{1 - E_2/100} - 1 \right) + t_R + t_{CB} + t_M \qquad \textbf{(8.2.3)}$$

where

E_1 is a factor which takes into account the superimposed effect of the operating time error caused by the inaccuracy of the current measurement and the operating time tolerance in the relay located closest to the fault spot (%) [1)]

E_2 is a factor which takes into account the superimposed effect of the operating time error caused by the inaccuracy of the current measurement and the operating time tolerance in the relay located next in the protection chain (%) [1)]

t_{CB} is the circuit breaker operating time

t_R is the retardation time

t_M is the safety margin

t_1 is the calculated operating time of the relay closest to the fault spot [1)]

1) Corresponds to the current value with which the grading time is determined, Figure 8.2.2.

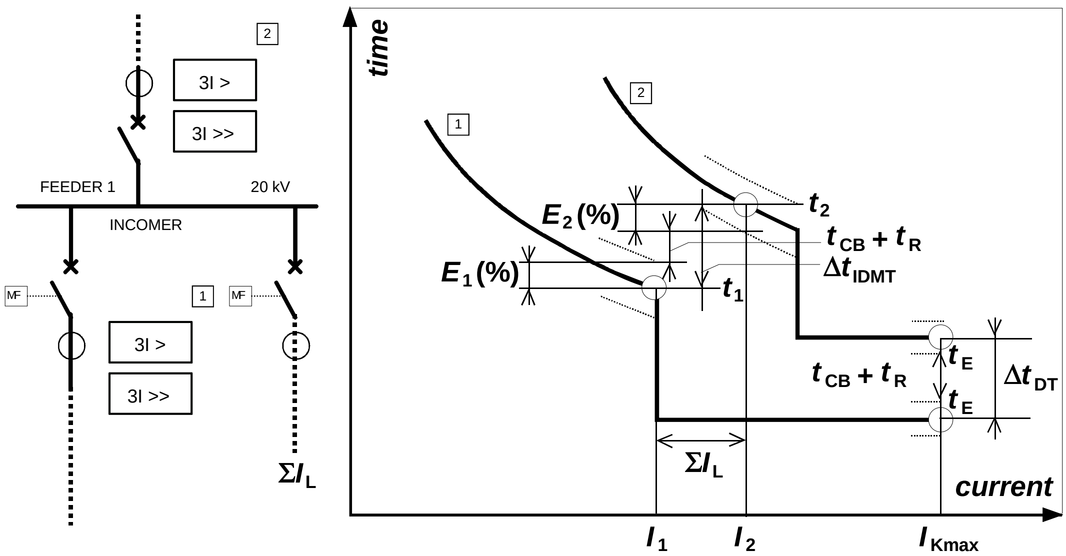


Figure 8.2.2: Grading time determination and factors affecting it. Notations: I_1, I_2 = current values with which the grading time between the low-set stages (3I>) is determined, I_{kmax} = maximum short-circuit current. For other notations, see Equations (8.2.2) and (8.2.3).

The tolerance values of the operating times are standardized, Table 8.2.2:

Table 8.2.2: Limit values, according to the BS 142 standard, of the operating times expressed as a percentage. *E* = accuracy class index

I/I>	Normal inverse	Very inverse	Extremely inverse	Long time inverse
2	2.22·*E*	2.34·*E*	2.44·*E*	2.34·*E*
5	1.13·*E*	1.26·*E*	1.48·*E*	1.26·*E*
7	-	-	-	1.00·*E*
10	1.01·*E*	1.01·*E*	1.02·*E*	-
20	1.00·*E*	1.00·*E*	1.00·*E*	-

Furthermore, the effect of the current measuring inaccuracy on the operating time of the inverse time protection must be observed. The effect can be evaluated using Equation (8.2.1) by giving values to the phase current according to the measuring inaccuracy used. The measuring inaccuracy is affected not only by the relay type but also by the accuracy of the measurement transformers. By adding the percentage of the operating time inaccuracies thus obtained to the values of Table 8.2.2 , the values of the factors E_1 and E_2 can be found.

Example of the determination of the grading time Δt_{DT}

The grading time between the high-set stages of the numerical protection relays in Figure 8.2.1 is determined using the Equation (8.2.2):

- 2 times the tolerance of the operating time: 2 x 25 ms
- Circuit breaker operating time: 50 ms
- Retardation time: 30 ms
- Safety margin: 20 ms
- Total: <u>150 ms</u>

The safety margin has been given the smallest possible value, and so the grading time Δt_{DT} =150 ms can be chosen, see Figure 8.2.1.

Example of the determination of the grading time Δt_{IDMT}

The grading time between the low-set stages of the numerical protection relays in Figure 8.2.1 is determined using Equation (8.2.3):

Current values with which the grading time is determined:

- Relay 1: I_1 = 1200 A ≈ 4.0 times the current setting of the stage
- Relay 2: I_2 = 1700 A ≈ 2.4 times the current setting of the stage

The selected curve type is normal inverse and the accuracy class E which equals 5%.

Table 8.2.2 is used and the operating time tolerances are selected to correspond to the currents I_1 and I_2 mentioned above. Table 8.2.2 shows that tolerances closest to those currents are 1.13·E (relay 1) or 6% and 2.22·E (relay 2) or about 11%.

The effect of the current measuring inaccuracy on the operating times in per cent from the calculated operating times t_1 and t_2 is determined using Equation (8.2.1), and when the joint current measuring inaccuracy of the relay and the measurement transformer is expected to be ±3%, Table 8.2.3 and Table 8.2.4. It must also be noted that the operating time error thus arising is independent of the setting of the time multiplier k of the inverse time curve.

Table 8.2.3: The effect of the current measuring inaccuracy on the operating times in relation to the calculated operating times t_1 of relay 1 for the current I_1

I_1 (x I>)	**Current measurement error** (%)	**Operating time error** $(t - t_1) / t_1$ **x 100** (%)
4.0	+3	-2
4.0	-3	+2

Table 8.2.4: The effect of the current measuring inaccuracy on the operating times in relation to the calculated operating times t_2 of relay 2 for the current I_2

I_2 (x I>)	**Current measurement error** (%)	**Operating time error** $(t - t_2) / t_2$ **x 100** (%)
2.4	+3	-3
2.4	-3	+3

The factors E_1 and E_2 are calculated as the sum of the absolute values of the errors:

- Relay 1: E_1=8%
- Relay 2: E_2=14%

By inserting factors E_1 and E_2 into Equation (8.2.3) and by observing that the calculated operating time t_1 of relay 1 is 1000 ms at 1200 A (4 x the set current), the required grading time can be calculated as follows:

- $t_1 \cdot \left(\frac{1+E_1/100}{1-E_2/100} - 1 \right)$: 260 ms
- CB-operating time: 50 ms
- Retardation time: 30 ms
- Safety margin: 20 ms
- Total: 360 ms

According to this, the grading time Δt_{IDMT} should be given a value of at least 360 ms, Figure 8.2.1.

The time-graded protection can also be implemented with definite time *underimpedance relays*. The relay measures the phase currents and phase-to-phase or phase-to-earth voltages. Based on these values, it determines the apparent impedance seen from the relay location. The relay operates if the measured impedance falls below the set start value. The set start value determines the so-called *reach* of the relay, which defines at which distance faults seen from the relaying point can still be detected. Owing to the measuring principle, the advantage of the impedance relay is that its operation is independent of the short-circuit power of the incoming network. The reach and the operating time of the relay are unchanged even if the source impedance changes, for example, when the network configuration is altered. Thus the relay operates reliably even though the short-circuit current would be particularly low. For this reason, underimpedance relays are frequently used as feeder protection relays in networks with low short-circuit power. Another typical application is the use of underimpedance relays as backup protection relays in vicinity of power plants where the fault current may decay under the set start value of overcurrent relays due to the effect of generators. If the protection of the outgoing lines from the power plant is also based on the impedance-measuring principle, selectivity between the relays can be easily obtained. The aforementioned salient principles of time grading also apply to underimpedance protection.

8.2.3 Time- and Current-graded Protection

Time- and current-graded protection can be used in cases where the fault current magnitudes in faults occurring in front of and behind the relaying point are different. Due to the different fault current levels using inverse time relays but also multi-stage definite time relays, different operating times can be obtained in either direction. In this way the requested time grading can be obtained and the operating time requirements can be fulfilled.

Figure 8.2.3 shows an example time- and current-graded overcurrent protection application. The study of the time grading towards one particular generator feeder is straightforward if the operating characteristic of the protection of the other generator feeders are combined in a single operating characteristic of a so-called equivalent generator feeder. This is obtained by multiplying the current values of the relay operating characteristic of a single generator by the number of generators in use at any time, operating characteristic 3G , Figure 8.2.3. From the selectivity diagram, it can be seen that when a fault occurs on feeder 4, for example, the total fault current fed by the network and the other feeders reaches the level indicated by ④. Thus, the operating time of the protection can even be shorter than 100 ms. The fault current fed by the equivalent generator is at least on the level indicated by ②. It can clearly be seen that in this way a reliable time-grading is obtained between the generator feeders also in cases where the fault current fed by the network is particularly low or if one generator is out of operation. The same method of study can be applied for planning the time-grading between the protection relays of the block transformer and the generator feeders for faults occurring in the network side. In this planning, special attention must be paid to the number of generators in operation and its effect on the the selectivity. Should machines be taken out of operation, the time-grading towards the network can be endangered if the settings of the protection relays of the block transformer are not adapted to the operating conditions at any time.

The protection practice described can also be used in the overcurrent protection of ring and meshed networks. Another area of application is the earth fault protection of effectively earthed ring and meshed networks.

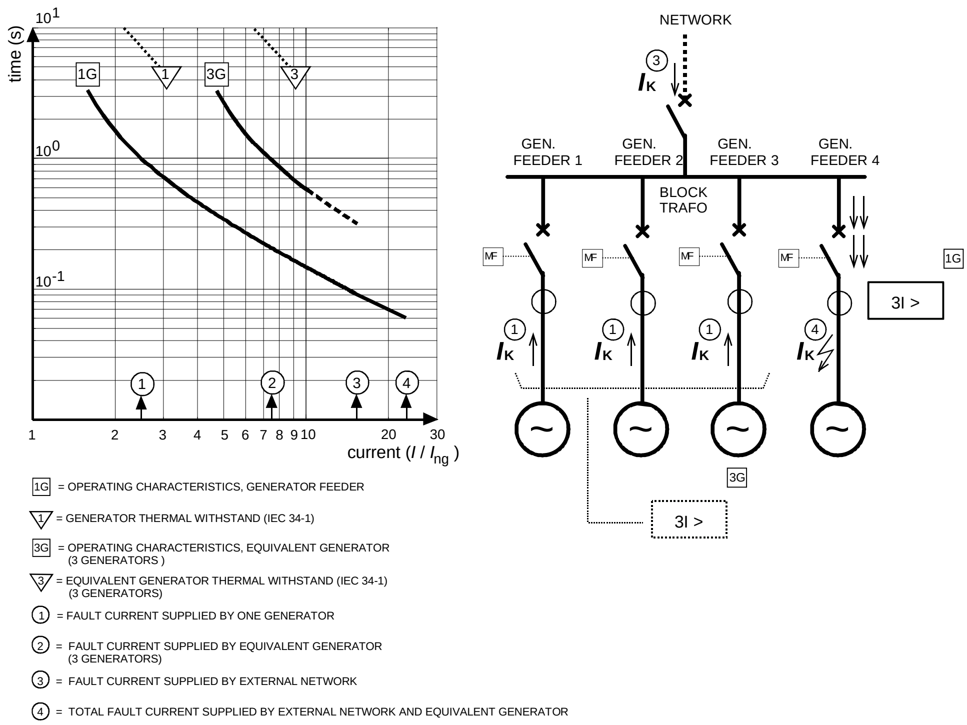


Figure 8.2.3: Power plant overcurrent protection implemented with time and current grading towards the generator feeders. The generators are of equal rated power and their inverse time relays share the same settings. I_{ng} = rated current of a single generator.

8.2.4 Time- and direction-graded protection

In ring and meshed networks, the selectivity of the protection can be based on directional overcurrent relays. Directional relays are needed as different operating times are required depending on the location of the fault, that is, if the fault spot is in front of the relaying point on the feeder or behind the relaying point, for example, on the incoming feeder or on the busbar system.

The directional overcurrent relay operates once the fault current exceeds the set start current and the direction of the fault current complies with the setting. Thus the selectivity of the protection is based on both time and current direction. The directional overcurrent protection can operate either according to definite time or inverse time characteristics and the aforementioned central principles of time-grading are also applicable to directional protection.

Typical applications based on directional protection are shown in Figure 8.2.4.

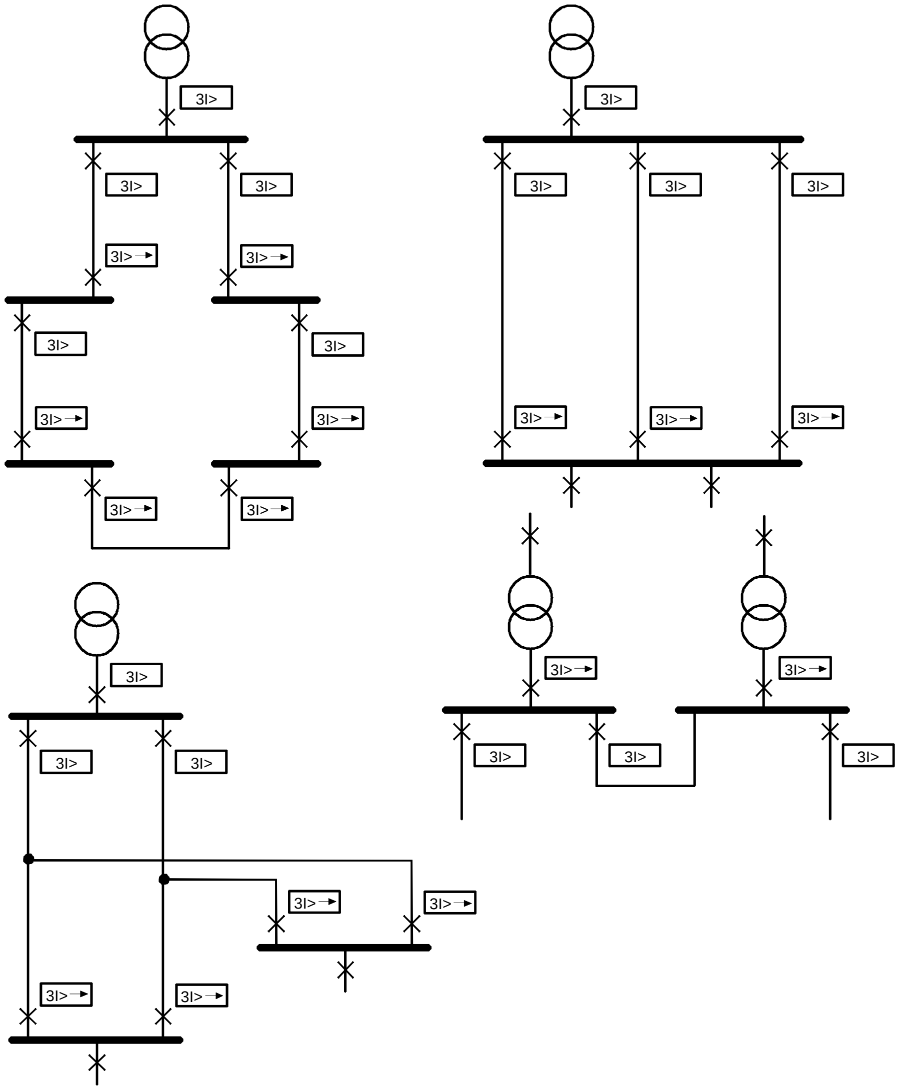
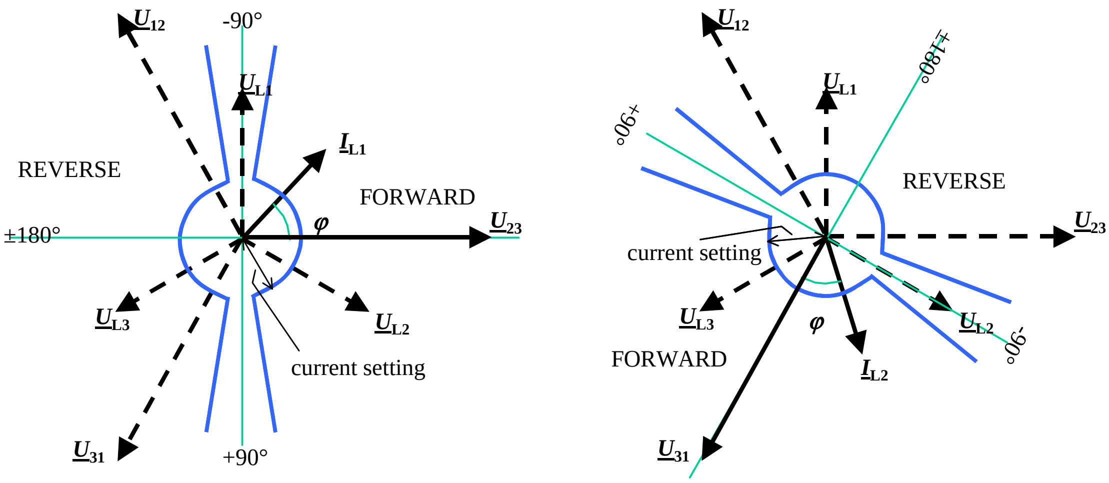


Figure 8.2.4: **Directional overcurrent relays applied to short-circuit protection of ring-type networks supplied from one point**

Various principles are used for determining the direction of the fault current. The most conventional way is to determine the direction phase-specifically so that the current phasor of each faulty phase is compared to the phasor of the opposite phase-to-phase voltage, for example, the direction of the phase current phasor $\underline{I}_{L1}$ is compared to the direction of the phasor $\underline{U}_{23}$. The relay operates if one or more of the direction comparisons show that the fault is located in the *forward* or *reverse* direction with regard to the set relay operating direction. An example operating characteristic formed in this way is shown in Figure 8.2.5.



Phase L1: **Phase L2**:

Figure 8.2.5: Direction determination principle of phases L1 and L2 based on using the opposite phase-to-phase voltage $\underline{U}_{L23}$ and $\underline{U}_{L31}$ correspondingly. The fault is located in forward direction.

Another way of determining the direction is first to indentify the faulty phases on the basis of the starts of the phase-specific overcurrent functions and then compare the difference between these current phasors to the difference between the other two phase-to-phase voltages, for example, the direction of the phasor $\underline{I}_{L1} - \underline{I}_{L2}$ is compared to the direction of the phasor $\underline{U}_{23} - \underline{U}_{31}$. Alternatively, the phasor $\underline{I}_{L1} - \underline{I}_{L2}$ can also be compared to the direction of the corresponding faulty phase-to-phase phasor $\underline{U}_{12}$, or to the corresponding positive-sequence voltage $\underline{U}_{1}$,which must be suitably rotated according to the fault type in question.

The said direction determination methods need to be supported by a *voltage memory* which stores the phasors of the pre-fault voltages. The relay uses the stored information for determination of the fault current direction in cases where the voltages are too low to be measured, that is, close-in short circuits. The advantage of the methods not using the corresponding faulty voltage is that the voltage memory is needed only in three-phase close-in short circuits. In two-phase short circuits, the voltages needed for the determination of the direction are always high enough to be measured. If using the faulty voltage in direction determination, the voltage memory is needed also in two-phase close-in short circuits. However, the advantage of this method is that the phase order of the power system has no impact on the direction determination.

The protection of ring and meshed networks can also be carried out using directional definite time *underimpedance* or *distance relays*. These relays are frequently used for the protection of transmission and sub-transmission networks, meshed or ring-operated distribution networks or weak radial networks. The advantages of the use of distance relays are the same as for the underimpedance relays in general, and the general time-grading principles also apply in this protection concept. To achieve a good and reliable selectivity and to fulfill the operating speed requirements as well as possible, it is typically necessary to implement multiple directional underimpedance stages. The reach of these stages defines the *zones* of protection toward the desired operating direction, which can be either forward of reverse. An example of this can be seen in Figure 8.2.6, where multiple-stage numerical distance relay units are applied to the short-circuit protection of a sub-transmission network. The figure also shows the principal reaches of the different zones of the example relay unit. The zones Z_1, Z_2 and Z_3 are set in the forward direction, that is, toward the protected line and the zone Z_4 in the reverse direction.

The zone Z_1 is *underreaching* the remote end station, making it possible to apply minimum operating times. Zone Z_2 is slightly *overreaching* the remote end, which means that the time coordination with zone Z_1 of the successive line is required; therefore the operating time is delayed as much as the grading margin requires. Zone Z_3 operates as an overreaching backup protection and the operating time must be selected so that it coordinates with the protection in the forward direction in all conditions. Zone Z_4 operates as an overreaching backup protection in the reverse direction, and the reach of this zone is selected so that it can detect faults even on the MV-side of the transformers. The operating time is selected accordingly. The main purpose of the zone Z_4 is to operate as a backup protection for the transformers. The main advantage of using distance relays in this example is that all faults occurring in the sub-transmission network can be cleared by the zones Z_1 or Z_2 in less than 0.2 seconds. Also possible fault current infeed from the distribution network side due to distributed generation, for example, does not affect the selectivity of the protection.

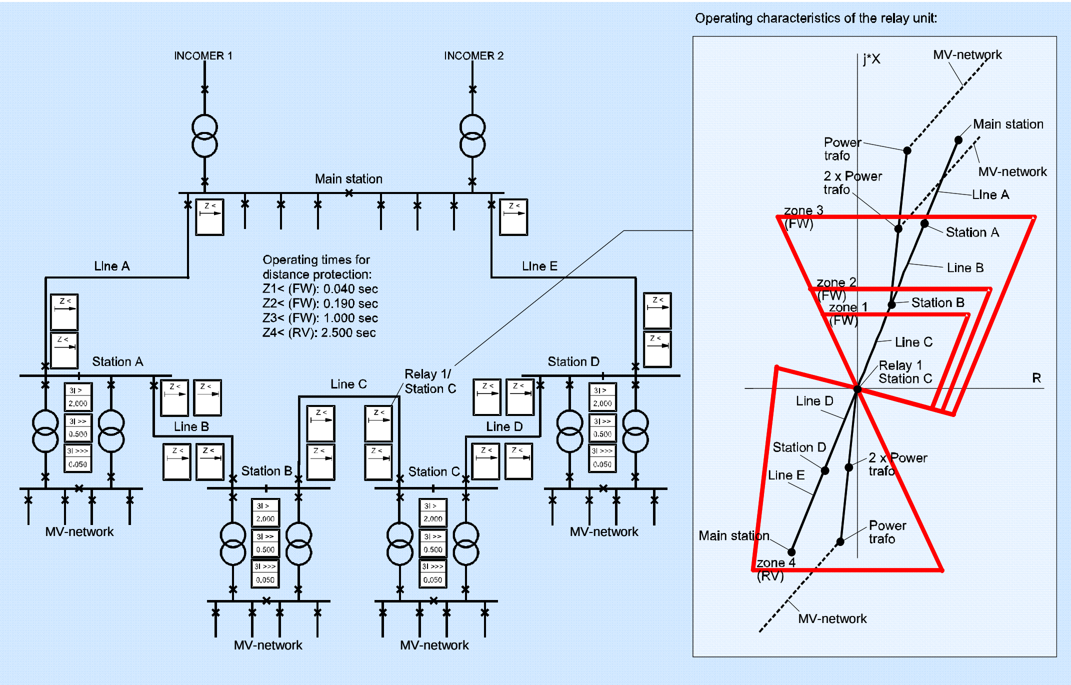


Figure 8.2.6: **The application principle of numerical multiple-stage distance protection for short-circuit protection of a sub-transmission ring main system. MV=distribution voltage. The notation 1 //- or 2 // transformer indicates the number of parallel transformers feeding the distribution network at any given time**

8.2.5 Current- and Impedance-graded Protection

In certain cases, protection principle based on *current and impedance grading* can be used to essentially accelerate the operation of the protection in faults arising close to the relaying point. The protection is implemented by using one directional or non-directional stage of the overcurrent or underimpedance relay.

The intention is to set the start current of the overcurrent stage so high that when a fault arises in front of the next relay in the protection chain, the concerned stage will not operate and no time-grading is needed. Correspondingly, when an underimpedance stage is used, the reach should be set low enough to obtain the corresponding function. For example, in Figure 8.2.6 the zone Z_1 operates according to this principle.

In accordance with the principle, the operating times of the stages can be set to their minimum without endangering the selectivity, because the protection operates only in faults occurring inside the protection zones determined by the current or impedance settings. The protection zones thus created do not overlap. Therefore, a normal time-graded protection arrangement should always be incorporated in parallel with the protection based on current or impedance grading.

When the settings of a current-graded protection arrangement are determined, the behavior of the relay type used in unsymmetrical faults must be taken into account, that is, does the DC-component of the fault current possibly cause a so-called *transient overreach* k_{DC} (%), which is defined as:

$$k_{DC} = \frac{I_S - I_F}{I_F} \cdot 100 \qquad \textbf{(8.2.4)}$$

where

I_S	is the RMS-value of the steady-state phase current at which the protection operates, that is, the set current.
I_F	is the RMS-value of the steady-state phase current onto which a superimposed full DC-component causes the protection to operate at the set current I_S

The primary value of the set start current of the current-graded overcurrent stage should be higher than or equal to I_{CS}

$$I_{CS} = k_m \cdot (1 + k_{DC}/100) \cdot I_K \qquad \textbf{(8.2.5)}$$

where

k_m	is a safety factor which takes into account the inaccuracy of the fault current calculation and the errors of the measurement transformers and the relay; a typical value equals 1.2
I_K	is the maximum fault current, which is calculated in the location of the successive/next relay in the protection chain

Especially the application of the current grading requires a sufficiently low *source impedance ratio* (SIR), Equation (8.2.6), at the relaying point. In the current-graded protection, this ensures that the fault current difference in the beginning and the end of the protected feeder, or in the HV- and the MV-side of the protected transformer, is high enough to enable suitable settings to be found for the protection. The reach of the current-graded protection in relation to the total length or impedance of the protected feeder depends on both the SIR-value and the I_{CS} -setting of the current-graded stage. The higher the SIR-value, the shorter the reach of the protection on the protected feeder will be.

$$SIR = \frac{|\underline{Z}_S|}{|\underline{Z}_L|} \qquad \textbf{(8.2.6)}$$

where

$\underline{Z}_S$	is the impedance of the incoming network, that is, the source impedance as seen from the relaying point
$\underline{Z}_L$	is the impedance of the protected feeder as seen from the relaying point

A high SIR-value may also limit the use of the impedance-graded protection concept because in such a case the magnitudes of the currents and voltages measured by the protection at the end of the zone and in the immediate vicinity may be so close to each other that measuring errors may cause a false operation of the protection.

8.2.6 Interlocking-based Protection

The purpose of *interlocking-based protection* is to accelerate the operation of the protection. The concept is especially suited for busbar protection, but it can also be implemented for the protection of short outgoing and incoming feeders and the transformer MV-side. The basic idea is to use interlocking between consecutive protective relays in the protection chain, Figure 8.2.7. This protection practice is generally used in combination with overcurrent relays.

In the example of Figure 8.2.7, the protected object is a busbar system, the bus tie circuit breaker of which is normally open. When a fault arises on the feeder, the overcurrent relays of both the incoming and outgoing feeders start. The overcurrent relay of the faulty feeder sends an interlocking signal that blocks the operation of the *3I>>>*-stage of the incoming feeder relay and trips the circuit breaker after the set time delay. When the fault appears within the area of protection, that is, on the busbar, no interlocking signals will be generated and the *3I>>>*-stage of the incoming feeder relay trips the circuit breaker after the set time delay, which is shorter than what would be required in the time-graded solution in the corresponding situation. When also the bus tie circuit breaker is incorporated in the interlocking chain, the protection operates selectively even if the bus tie circuit breaker were closed.

The interlocking-based protection concept is best suited for use in radial networks, where the short-circuit currents are considerably higher than the load currents. In this case, a current setting value can easily be found for the overcurrent stage that issues the interlocking signal. It must also be noted that the stage issuing the interlocking signal is not allowed to start for faults within the protected area if the fault current can also be fed by the concerned feeder (backfeed). Then the start current of the stage which issues the interlocking signal must be set higher than the backfeed current (c.f. current selective protection) or a directional relay must be used for issuing the interlocking signal.

For a reliable and selective operation, the overcurrent stage to be interlocked must be slightly delayed. In the example of Figure 8.2.7, the *3I>>>*-stage of the incoming feeder relay is used for this purpose. The required delay depends on the features of the relay type applied, the accuracy limit factors of the CTs and the implementation of the interlocking channel. The required operating delay can be estimated by observing the following:

- Start time of the overcurrent stage issuing the interlocking signal. This starting time includes both the start delay of the stage and the inherent delay of the binary output of the relay (typically < 40 ms)
- Retardation time of the overcurrent stage to be blocked including the response time of the binary input of the relay (typically < 30 ms)
- Safety margin that, for example, takes into account the effect of the possible saturation of the current transformers (typically 1 to 2 cycles)

By summing the delay times mentioned, the shortest possible time setting for the overcurrent stage to be blocked is obtained. Typically this time is about 100 ms, provided that no auxiliary relays are incorporated in the blocking circuit.

The interlocking protection principle can also be applied in ring or meshed networks, in which case directional overcurrent relays or distance relays are to be used.

Because the protection areas of the interlocking-based protection concept are not overlapping and because they do not reach into the protection area of the next relays in the protection chain, a parallel time-graded protection system must always be used. In Figure 8.2.7 this time-graded protection is implemented with one to three stages depending on the relay location.

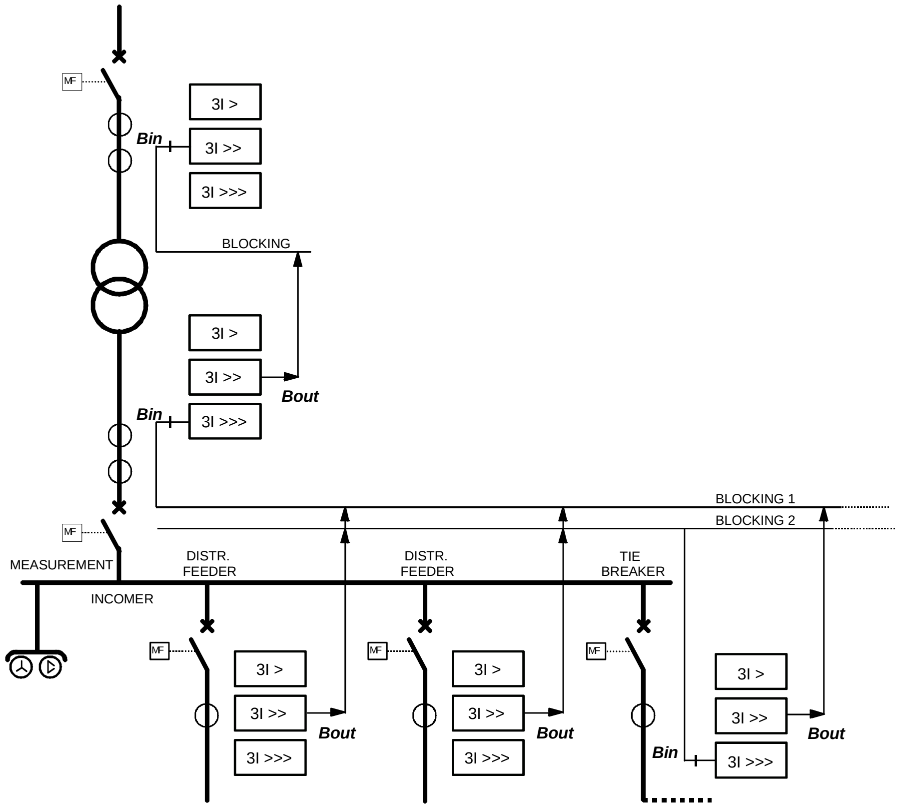


Figure 8.2.7: Interlocking-based protection system applied to the protection of the busbar and the transformer. B_{out} = transmitted interlocking signal, B_{in} = received interlocking signal, which blocks the operation of the concerned overcurrent stage.

8.2.7 Differential Protection

Differential protection is a useful method of protection that can be applied to the protection of any network component, such as transformers, machines, busbars, lines and feeders. The differential relay compares the incoming phase currents of an object to the outgoing phase currents of the same object. If these currents differ from each other as to the amplitude or phase angle or both more than allowed by the setting values of the relay, the relay will trip. The measuring principle ensures that the relay operates exclusively on faults inside the area of protection, which means that the protection is *absolutely selective*. Therefore the operating time of the protection is very short, typically shorter than one cycle. The area of protection is defined as the area between the current-measuring points. Another advantage brought on by the measuring principle is the high sensitivity: the protection may respond to a fault current of only a few percent of the rated current. The obtainable sensitivity depends on the relay type used, the characteristics of the current transformers and the protected object.

According to their operating principles, the differential protection can be divided into *low-impedance* and *high-impedance differential schemes*.

8.2.7.1 Low-impedance principle

A low-impedance differential scheme measures the currents on either side of the protected object and forms from these a *differential current* I_d , Figure 8.2.8. In practice, a small differential current, mainly caused by measuring errors of the current transformers and the relay, can be noticed even though there is no fault within the area of protection. In transformer protection applications, a so-called apparent differential current like this is additionally caused by the no-load current of the transformer, the position of the tap changer and momentarily by the transformer inrush current, which fully appears as differential current. The magnitude of the differential current caused by the measuring errors and the position of the tap changer is directly proportional to the load current of the transformer. A particularly crucial situation from the apparent differential current point of view appears at faults just outside the area of protection. The through-fault current is high and may contain a DC-component which may cause saturation of the current transformers resulting in a momentary increase in the differential current. To avoid a false operation of the differential relay, the relay must be stabilized, which means that the higher the through-fault current, the higher differential current is required for tripping. The *stabilizing current* I_b is formed from the phase currents measured on both sides of the protected object. An example of the operating characteristic of a stabilized differential relay is shown in Figure 8.2.8. The shape of the characteristic is defined by the *basic setting*, *starting ratio* and *the second turning point*, Figure 8.2.8. For stabilizing current values greater than the second turning point, the starting ratio is fixed.

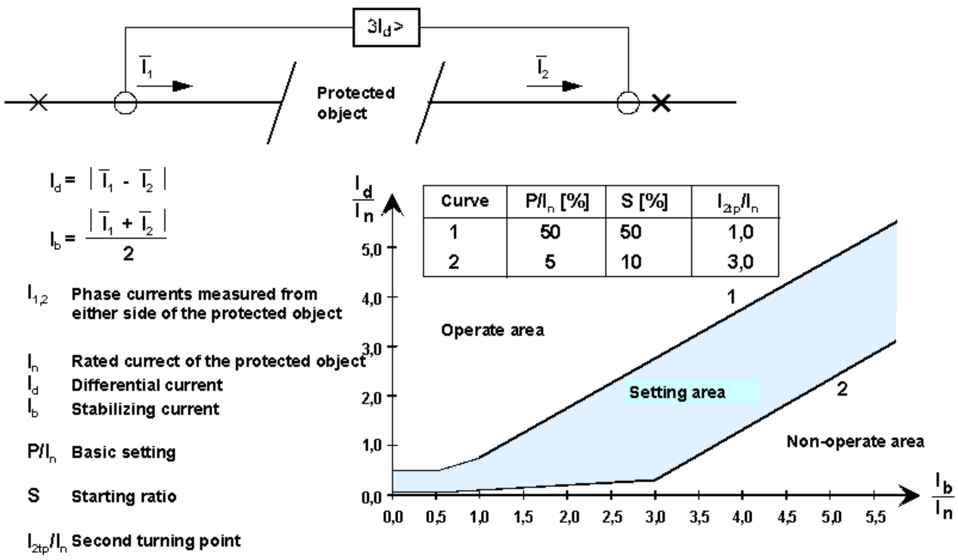


Figure 8.2.8: Operating characteristic of a low-impedance type differential current relay

As the name implies, the basic setting defines the basic sensitivity of the relay under no-load conditions of the protected object. The basic setting must be higher than, for example, the transformer excitation current or the line-charging current at maximum operating voltage to avoid a false operation of the relay. The basic setting also affects the level of the entire characteristic curve and thus also the operating sensitivity at higher stabilizing current levels.

The starting ratio caters for the sources of the apparent differential current, which are directly proportional to the through-flowing current. It is mainly the starting ratio together with the second turning point that determines the operating sensitivity of the relay for internal transformer or machine faults when these objects are loaded. Winding and interturn short circuits and earth faults in the windings or elsewhere in the protected area are fault types that call for a sensitive and fast operation of the protection.

The second turning point also affects the *stability* of the protection at faults outside the area of protection. In this situation, the relay must not operate incorrectly and trip the circuit breaker under the influence of the apparent differential current. The lower the setting of the second turning point, the better the stability obtained will be. On the other hand, the sensitivity of the relay for internal faults may be decreased in the same time, particularly in the transformer protection applications. By taking notice of the accuracy limit factors of the CTs, the fault current levels and their supply directions and the sensitivity requirements of the protected object, the setting of the second turning point is in general easily found.

At stabilizing current levels above the second turning point, the high starting ratio secures stability at faults arising outside the area of protection.

Stability problems may be caused by switching inrush currents. When a protected power transformer is energized, the inrush current fully appears as differential current, in which case the stabilization of the relay alone is not enough to prevent false relay operations. This situation calls for a *blocking function based on the second harmonic* to inhibit the operation of the stabilized stage. The second harmonic is typically abundantly present in the inrush current.

Problems may also arise when the transformer inrush current fed by the protected generator is fairly high compared to the rated current. In these cases, the unsymmetrical phase currents containing second harmonics may cause non-simultaneous saturation of the current transformers and thus apparent differential current for the relay. To secure the operation of the relay under these circumstances, the activation of the second harmonic-based blocking function is often justifiable.

In transformer protection applications, the stability is also endangered by a temporary overvoltage. The increasing voltage generates a growing magnetizing current because of the saturation of the transformer, which is fully seen as differential current. When the ratio between the differential current and the stabilizing current exceeds the settings, the relay operates. The operation can be inhibited by incorporating a *blocking function based on the fifth harmonic*. The magnetizing current of a saturated power transformer contains a great deal of this particular harmonic. If the overvoltage situation becomes worse, the proportion of the fifth harmonic typically grows up to a certain knee point level. At this point it may be appropriate to remove the blocking and to enable the relay to operate in order to prevent too excessive overexcitation of the transformer. This can be done with the *release function of the fifth harmonic-based blocking*.

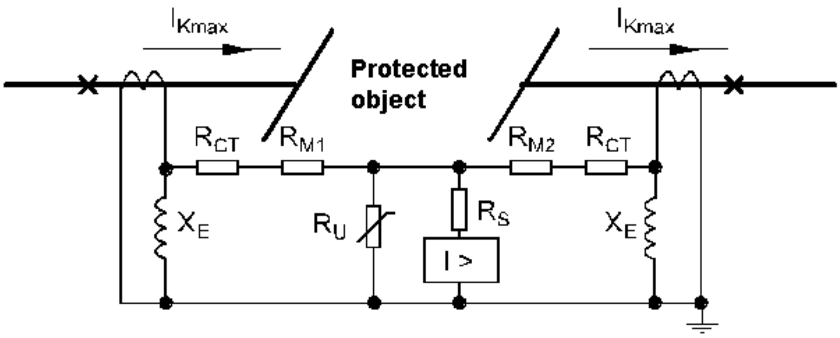
To obtain as fast and dependable relay operation as possible at faults inside the area of protection, a high-set stage is used in addition to the stabilized stage. The high-set stage cannot be blocked and it is unstabilized. The high-set stage operates when the differential current momentarily exceeds the set start value.

For a fast and dependable operation of the high-set stage, the accuracy limit factor of the current transformers used in the protection must be high enough. This will also prevent the unnecessary operation of the second harmonic blocking function and in this way additional delay in operation of the stabilized stage can be prevented. On the one hand, a sufficient similarity in the accuracy limit factors of the current transformers used in the protection further assures that the relay maintains its stability at faults outside the area of protection.

8.2.7.2 High-impedance principle

Thanks to its operating principle, the *high-impedance differential scheme* is particularly easy to implement and set and has a high operational reliability, Figure 8.2.9. The stabilization of the high-impedance scheme is performed by a separate *stabilizing resistor*. As the name implies, this resistor is employed for the prevention of false relay operations on faults outside the area of protection. Such operations may be caused by the differential current arising from non-simultaneous saturation of the current transformers. Because the current transformer circuits are galvanically interconnected, all the current transformers of the protection should have the same turns ratio. The use of intermediate current transformers is not recommended as this increases the requirements set on the main current transformers and lowers the sensitivity of the protection. The high-impedance principle is particularly well suited for the short-circuit protection of machines, short lines and busbar systems and the earth-fault protection of these and transformers in effectively earthed and low-impedance-earthed networks.

The design of the stabilization of the high-impedance scheme is based on the assumption that one of the current transformers of the protection fully saturates at faults outside the area of protection, while the rest of the current transformers do not saturate at all. The idea is to route the apparent differential current formed in the mentioned way to flow through the saturated current transformer rather than through the relay. Because the impedance of the saturated current transformer is low, a high resistance, that is, the stabilizing resistor, is connected in series with the relay circuit. Now the entire differential current is forced to flow through the secondary circuit of the saturated current transformer, which can be described by short-circuiting the magnetizing reactance X_E in Figure 8.2.9. The voltage drop formed over the secondary circuit will then be the same as that over the relay circuit, Figure 8.2.9. This *stabilizing voltage* must not cause a relay operation.



$$U_S = (R_{Mmax} + R_{CT}) * (I_{Kmax} / n)$$

U_S = **Stabilizing voltage**
R_{Mmax} = **Maximum resistance of the secondary measuring loop, i.e. max(R_{M1},R_{M2})**
I_{kmax} = **Highest through-fault current**
n = **Transformation ratio of the CTs**
R_{CT} = **Resistance of the CT secondary winding**

Figure 8.2.9: Single-phase equivalent circuit diagram and operating principle at faults outside the area of protection, and calculation of the stabilizing voltage U_S being the setting criterion for the relay. R_S = stabilizing resistor, R_U = voltage dependent resistor (varistor).

When the protection is implemented using a voltage relay, the selected setting must be equal to or exceed the calculated stabilizing voltage. The value of the stabilizing resistor is determined according to this voltage setting. In case of a voltage relay, the stabilizing resistor is often integrated into the relay. When the protection is implemented using a current relay, the current value at which the relay should operate must be determined first. By means of the stabilizing voltage and the current setting, the value of the stabilizing resistor is obtained. Typically in case of a current relay the stabilizing resistor must be separately installed and connected to the relay circuit.

On faults inside the area of protection, the current transformers attempt to feed a secondary current proportional to the short-circuit current through the relay. But because the impedance of the relay circuit is high, the secondary voltage may exceed the ratings of the relay and the secondary wiring. For this reason, a voltage-dependent resistor is to be connected in parallel with the relay in order to limit the voltage to a safe level.

The current transformers used in the high-impedance protection applications must have an adequate accuracy limit factor to be capable of supplying enough current to the relaying circuit on faults inside the area of protection. This requirement is fulfilled if the knee point voltage of the current transformers is at least twice the chosen stabilizing voltage. This way, the protection operates fast and reliably also for differential current levels just slightly exceeding the set value. The protection requires class X or PX current transformers according to BS 3938 or IEC 60044-1 respectively, the repetition capability of which is determined by the knee point voltage and the resistance of the secondary circuit. In the specification of the class X or PX CTs, the magnetizing current corresponding to the knee point voltage is also given. This current value is needed for the calculation of the overall sensitivity of the protection.

Document revision history

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A / 08 April 2011	First revision

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