

EUROPROT +

**Setting guide
for the distance protection function**



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1 Setting of distance protection function

1.1 Setting the polygon characteristics

1.1.1 Impedance characteristics of the distance protection

The distance protection function calculates the positive sequence impedance in six measuring loops. The calculated R_1 and $X_1=\omega L_1$ co-ordinate values define six points on the complex impedance plane. The protection function compares these points with the „polygon” characteristics of the distance protection, shown in Figure 1-1.

The main setting values of “Zone R” and “Zone X” refer to the positive sequence impedance of the fault loop. The resistance value includes the positive sequence fault resistance of the possible electric arc and, in case of a ground fault, the positive sequence resistance of the tower grounding as well.

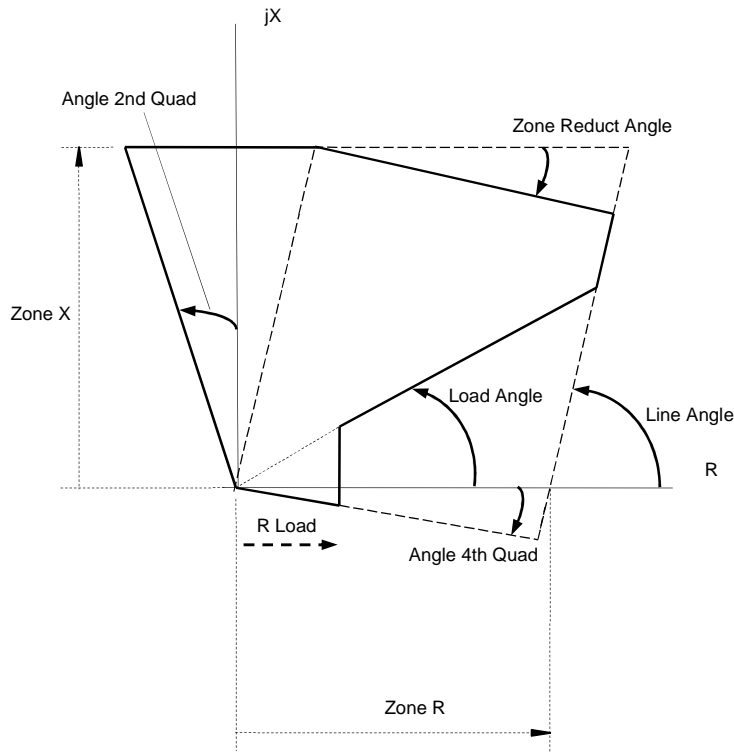


Figure 1-1 The polygon characteristics of the distance protection function on the complex plane (Example: Zone 1)

If a measured impedance point is inside the polygon, shown in Figure 1-1, then the algorithm generates the true value of the related output binary signal.

The distance protection has six zones applying polygon characteristics, each of them have independent parameter setting values.

1.1.2 The parameters

The parameters needed in the polygon evaluation procedure of the distance protection function are explained in the following tables.

Enumerated parameters

The enumerated parameters of the zones (according to Table 1-1) serve disabling of the zones one-by-one, or setting the direction:

- “Forward” (the orientation of the polygon is according to Figure 1-1),
- “Backward” (the orientation of the polygon is according to Figure 1-2),
- “NonDirectional” (the extended polygon is according to Figure 1-3),

NOTE: Zone 1 cannot be “NonDirectional”. It is the free user’s choice to select the required directionality.

Parameter name	Title	Selection range	Default
Parameters to select directionality of the individual zones:			
DIS21_Z1_EPar_	Operation Zone1	Off, Forward, Backward	Forward
DIS21_Z2_EPar_	Operation Zone2	Off, Forward, Backward, NonDirectional	Forward
DIS21_Z3_EPar_	Operation Zone3	Off, Forward, Backward, NonDirectional	Forward
DIS21_Z4_EPar_	Operation Zone4	Off, Forward, Backward, NonDirectional	Forward
DIS21_Z5_EPar_	Operation Zone5	Off, Forward, Backward, NonDirectional	Backward

Table 1-1 Enumerated parameters for the POLY logic

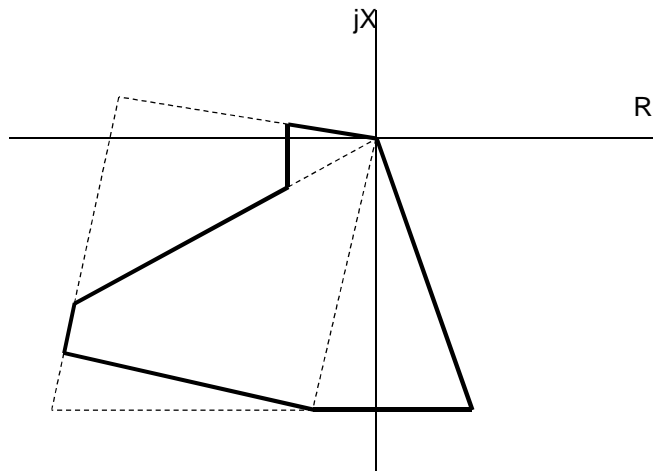


Figure 1-2 The polygon characteristics of the distance protection function with “Backward” setting (Example Zone1)

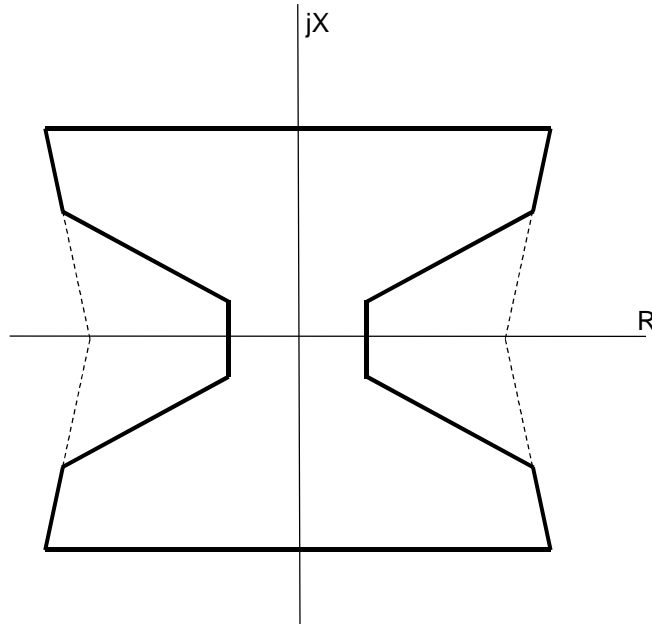


Figure 1-3 The polygon characteristics of the distance protection function Zones 2-5 with “NonDirctional” setting

Boolean parameters for the individual zones are listed in Table 1-2. These parameters define if the operation of the function in the zones generate trip command (0) or indicate starting only (1). The usual setting is the default; the faults detected in the individual zones generate also a trip command. For special applications, the trip command can be blocked.

Note: if also the start signals need to be blocked the switch the selected “Operation” parameters (Table 1-1) to “Off”.

Parameter name	Title	Default	Explanation
DIS21_Z1St_BPar_	Zone1 Start Only	0	0 for Zone1 to generate trip command
DIS21_Z2St_BPar_	Zone2 Start Only	0	0 for Zone2 to generate trip command
DIS21_Z3St_BPar_	Zone3 Start Only	0	0 for Zone3 to generate trip command
DIS21_Z4St_BPar_	Zone4 Start Only	0	0 for Zone4 to generate trip command
DIS21_Z5St_BPar_	Zone5 Start Only	0	0 for Zone5 to generate trip command

Table 1-2 Boolean parameters of the phase selection logic

Floating point parameters

The floating point parameters of the zones (according to Table 1-3) serve setting the main sizes of the polygons for the zones one-by-one. See Figure 1-1.

These parameters can be calculated if the parameters of the protected lines or cables are known. The calculation methods are demonstrated in Appendix 1.

Parameter name	Title	Dim.	Min	Max	Default
R and X setting values for the five zones individually:					
DIS21_Z1R_FPar	Zone1 R	ohm	0.1	200	10
DIS21_Z2R_FPar	Zone2 R	ohm	0.1	200	10
DIS21_Z3R_FPar	Zone3 R	ohm	0.1	200	10
DIS21_Z4R_FPar	Zone4 R	ohm	0.1	200	10
DIS21_Z5R_FPar	Zone5 R	ohm	0.1	200	10
DIS21_Z1X_FPar	Zone1 X	ohm	0.1	200	10
DIS21_Z2X_FPar	Zone2 X	ohm	0.1	200	10
DIS21_Z3X_FPar	Zone3 X	ohm	0.1	200	10
DIS21_Z4X_FPar	Zone4 X	ohm	0.1	200	10
DIS21_Z5X_FPar	Zone5 X	ohm	0.1	200	10
Load encroachment setting:					
DIS21_LdR_FPar	R Load	ohm	0.1	200	10
Zero sequence current compensation factors for the five zones individually:					
DIS21_Z1aX_FPar_	Zone1 (Xo-X1)/3X1		0	5	1
DIS21_Z1aR_FPar_	Zone1 (Ro-R1)/3R1		0	5	1
DIS21_Z2aX_FPar_	Zone2 (Xo-X1)/3X1		0	5	1
DIS21_Z2aR_FPar_	Zone2 (Ro-R1)/3R1		0	5	1
DIS21_Z3aX_FPar_	Zone3 (Xo-X1)/3X1		0	5	1
DIS21_Z3aR_FPar_	Zone3 (Ro-R1)/3R1		0	5	1
DIS21_Z4aX_FPar_	Zone4 (Xo-X1)/3X1		0	5	1
DIS21_Z4aR_FPar_	Zone4 (Ro-R1)/3R1		0	5	1
DIS21_Z5aX_FPar_	Zone5 (Xo-X1)/3X1		0	5	1
DIS21_Z5aR_FPar_	Zone5 (Ro-R1)/3R1		0	5	1
Parallel line coupling factor:					
DIS21_a2X_FPar_	Par Line Xm/3X1		0	5	0
DIS21_a2R_FPar_	Par Line Rm/3R1		0	5	0
Data of the protected line for displaying distance:					
DIS21_Lgth_FPar_	Line Length	km	0.1	1000	100
DIS21_LReact_FPar_	Line Reactance	ohm	0.1	200	10

Table 1-3 Floating point parameters for the distance protection

Integer parameters

The integer parameters in * "Zone Reduct Angle" parameter is valid for Zone 1 only

Table 1-4 show the "fine-tuning" parameters of the polygon characteristics. For explanation, see Figure 1-1.

Parameter name	Title	Unit	Min	Max	Step	Default
Definition of the polygon characteristic angle in the 2 nd quadrant of the impedance plane:						
DIS21_dirRX_IPar_	Angle 2nd Quad	deg	0	30	1	15
Definition of the polygon characteristic angle in the 4 th quadrant of the impedance plane:						
DIS21_dirXR_IPar_	Angle 4th Quad	deg	0	30	1	15
Definition of the Zone 1 reduction angle of the polygon characteristic on the impedance plane:						
DIS21_Cut_IPar_	Zone Reduct Angle*	deg	0	40	1	0
Definition of the load angle of the polygon characteristic:						
DIS21_LdAng_IPar_	Load Angle	deg	0	45	1	30
Definition of the line angle:						
DIS21_LinAng_IPar_	Line Angle	deg	45	90	1	75

* "Zone Reduct Angle" parameter is valid for Zone 1 only

Table 1-4 Integer parameters for the POLY logic

Timer parameters

The timer parameters, together with the basic zone settings (in Table 1-3) serve selectivity of the whole protection system. These setting values must be coordinated with all other protection settings of the system.

Usually the operation in zone 1 has no additional time delay ("Zone1 Time Delay" is set to 0). Between the subsequent time-delay setting values the difference is the "selective time step". For these values, please check the practice of the application.

Parameter name	Title	Unit	Min	Max	Step	Default
Time delay for the zones individually						
DIS21_Z1Del_TPar_	Zone1 Time Delay	ms	0	60000	1	0
DIS21_Z2Del_TPar_	Zone2 Time Delay	ms	0	60000	1	400
DIS21_Z3Del_TPar_	Zone3 Time Delay	ms	0	60000	1	800
DIS21_Z4Del_TPar_	Zone4 Time Delay	ms	0	60000	1	2000
DIS21_Z5Del_TPar_	Zone5 Time Delay	ms	0	60000	1	2000

Table 1-5 Timer parameters of the distance protection function

1.1.1 Setting calculation

1.1.1.1 Setting the first impedance stage

The role of the first impedance stage is usually to protect the most of the line (or cable). The first stage is not allowed to operate together with the protections located on the outgoing lines of the far end bus bar, even if the protection has positive measuring (impedance) error, so its setting value must be less than the total positive sequence impedance of the protected line. The equation for selective setting the first stage is:

$$Z' \leq \frac{Z_L}{(1 + \varepsilon)}$$

Where

- Z' the setting value of the first impedance stage,
- Z_L the positive sequence impedance of the line to be protected,
- ε the security factor, usually 0.15

Example for setting the first impedance stage:

For the setting procedure, the following data are necessary:

Data:

120 kV overhead line,

Line length: length = 40 km

Per unit positive sequence reactance: $x1 = 0.41 \text{ } \Omega/\text{km}$

Per unit positive sequence resistance: $r1 = 0.12 \text{ } \Omega/\text{km}$

Per unit zero sequence reactance: $x0 = 1.03 \text{ } \Omega/\text{km}$

Per unit zero sequence resistance: $r0 = 0.30 \text{ } \Omega/\text{km}$

Voltage transformer turns ratio: $au = 120 \text{ kV}/0.1 \text{ kV}$

Current transformer turns ratio: $ai = 600 \text{ A} / 5 \text{ A}$

Calculation:

Zone1 X [Ohm]

Setting of the reactance is calculated according to the „classical“ setting formula:

$$X^I \leq \frac{X_{Line}}{(1 + \epsilon)}$$

The parameter values are to be given in secondary Ohm units.

The primary reactance to be set:

$$X_{prim.} = \text{length} * x1 / (1 + \epsilon) = 40\text{km} * 0.41 \text{ } \Omega/\text{km} / (1 + 0.15) = 14.26 \text{ } \Omega$$

Transformed to secondary value:

$$X_{second.} = ai/au * X_{prim.} = (600/5) / (120/0.1) * 14.26 \text{ } \Omega = 1.426 \text{ } \Omega$$

The value to be set:

$$\underline{\text{Zone1 X}} = X_{second.} = \underline{1.426 \text{ } \Omega}$$

Zone1 R [Ohm]

When setting the resistance, the following considerations must be made:

The resistance value of the line section to be protected, calculated with the factor $1/(1 + \epsilon)$ must be within the polygon.

In case of electric arc at the fault location, which is approximated with a resistance value added to the impedance of the line section. This increases the total resistance value, which must be within the polygon too. Remember Warrington formula for calculation the arc resistance caused by I RMS current and d arc length:

$$R_{arc} [\Omega] = \frac{28700 * d^{[m]}}{I^{[A]1.4}}$$

For example $d = 1 \text{ m}$ and $I = 500 \text{ A}$ $R_{arc} = 4.78 \text{ } \Omega$. If $I = 1000 \text{ A}$, this value decreases to $1.81 \text{ } \Omega$ (primary value).

In case of earth fault, the earth resistance at the fault location must be taken into consideration. If the steel towers are interconnected with each other with the earth wire, this resistance can be small. The sum of the mentioned resistance (line resistance + arc + earth resistance) must be within the polygon.

The calculated impedance contains errors because of the inaccuracy of the algorithm, the amplitude and phase errors of the VT-s and CT-s, the measuring errors caused by the short-circuit transients. The sequence of calculated impedances is not a single point on the impedance plane, but they will cover a certain area. The characteristics must be set to include this area as well.

The power supply from the far end of the protected line distorts the measured resistance (magnitude and also phase angle).

Because of the mentioned effects, the characteristics must be widened in R direction.

The following facts however contradict this requirement:

The role of the R setting is to exclude the calculated impedance in case of high load of the line. The small "normal" impedance during heavy load is not allowed to start the protection. See the setting of the load by "R Load" and "Load Angle", explained below.

The unwanted operation during power swings (without fault on the protected line) has to be avoided if possible. See the power swing setting explained below.

In case of a fault during heavy load, the impedance calculated for the healthy phase(s) approaches the borders of the characteristics. The phase-selectivity requires a proper R setting value, which excludes these impedance values.

Because of the contradiction of the requirements, an engineering compromise has to be applied: the setting must be selected based on experiences.

For example in case of a 120 kV transmission line, the compromise

Zone 1 $R=Zone1 X$ can be an adequate setting. The primary value 14.26 Ω can include the

- 40 km*0.056 Ω /km /(1+0.15)= 1.95 Ω resistance of the line,
- arc resistance,
- earth resistance as well.

If needed, this value can be corrected according to the experience.

The value of parameter Zone 1R is the same as that of parameter Zone 1X, secondary values.

$$\underline{Zone1 R = Zone1 X = 1.426 \Omega}$$

Line Angle

The influence of this parameter is to set the slope of the rightmost line of the impedance characteristic as it is shown in Figure 1-1. Usually it is set according to the given data of the protected line

$$\text{Line Angle} = \text{ArcTan}(x1/r1)$$

Using the data given for the 120 kV line:

per unit positive sequence resistance: 0.12 Ω /km

per unit positive sequence reactance: 0.41 Ω /km

$$\text{Line Angle} = \text{ArcTan}(0.41/0.12) = 73.69^\circ$$

The setting:

$$\underline{\text{Line Angle} = 73^\circ}$$

NOTE1: The line angle intersects the point of the horizontal line of the distance protection (See "Zone1 X" setting) where the "Zone Reduction Angle" parameter starts to modify the shape of the characteristic. Related to the setting of the parameter "Zone Reduction Angle" see the consideration in Appendix below.

NOTE2: To cover better the increased measured resistance in case of faults near to the far line end this parameter can also be set to a lower value.

Angle 4th Quad

Slope of the characteristics border line $\alpha = \arctg(|X/R|)$ in the negative reactance area (see Figure 1-1).

When setting this parameter the following considerations are to be made:

The principal border of the possible impedance area is the R axis since negative reactance is not possible in case of fault on the line. The impedance is on the R axis, when the fault is exactly at the current transformer, and the fault resistance is measured. The characteristics with safety margin must include this measured point.

The power supply from the far end of the line can distort the voltage of the fault resistance. The impedance is calculated with the measured I_R current and the U_R voltage at the relay location. The U_R voltage includes the voltage drop on the fault resistance too. If before the fault, there was a heavy power transfer on the line, this voltage drop caused by the far-end equivalent voltage source has a different vector position, than the voltage drop caused by the voltage source at the relay location. The voltage on the resistance can have a considerable phase shift. In case of unfavorable direction, it can turn the measured impedance point out of the characteristics. The protection against this effect is the "opening" of the inclination of the characteristics.

In case of a close-in-fault, the voltage can have a very small value, which cannot be sufficient when calculating the fault direction. In this case, the voltage values stored in the memory are applied to calculate the direction. During a fault, the power flow can change largely, as compared to the flow during normal operation of the network, and the voltage during a fault is phase-shifted as compared to the healthy voltage. This phase shift depends on the impedance and on the power flow. To decide a correct direction, it is useful to "open" the inclination of the characteristic line.

Due to the inaccuracy of the algorithm, the measuring errors caused by the short-circuit transients and the angle error of the measuring transformers the impedance contains inaccuracy, too. In this way, the calculated impedance does not determine a single point on the impedance plane, but several points, which can cover a rather large area in the subsequent sampling sequence. The characteristics must include this area as well. Because of the effects mentioned above it is useful to open the characteristics.

The following fact however contradicts the opening:

The characteristics must exclude the impedance measured in the healthy loops. The separation of the measuring loops based on the zero sequence current can exclude the measured impedance values of some loops, but the remaining impedance values measured in healthy loops can approach the characteristics, especially in case of heavy pre-fault load. An example is a close-in single phase-to-earth fault in phase „A“, when the impedance measured in the healthy loop „B“ is close to the border of the characteristics. Therefore, it is useful to set the characteristics as closed as possible.

The requirements are in contradiction, an engineering compromise is needed to set the slope based on the experience. When making these considerations the mentioned VECTOR program of PROTECTA can help identifying the critical situations, and investigating the effect of the actual parameters as well.

This parameter can be calculated as

$$\text{Angle 4th Quad} = \text{ArcTan} (|X|/R) [\text{deg}]$$

Here the ratio defines the slope only; X and R have no relationship to the positive sequence impedance data of the line. The unit of this parameter is degrees.

For example, in case of a 120 kV transmission line the proposed setting value is Angle 4th Quad = 15 deg. The greatest possible opening is 30 deg. If needed, this setting can be modified.

The proposed setting:

$$\underline{\text{Angle 4th Quad} = 15 \text{ deg}}$$

This angle is common for all five zones.

Angle 2nd Quad

Slope of the characteristics border line $\beta = \arctg(|R|/X)$ in the negative resistance area (see Figure 1-1).

When setting this parameter, similarly to the setting of the slope "Angle 4th Quad," the following considerations are to be made:

The principal border of the possible impedance values is the impedance of the line. The points of this line are measured in case of solid faults along the line. The characteristics must include these points.

In case of close in faults, the voltage will be a very small value, which cannot be sufficient when calculating the fault direction. In this case, the voltage values stored in the memory are to be applied to calculate the direction. During a fault, the power flow can change largely, as compared to the flow during normal operation of the network, and the voltage during fault is rotated, as compared to the healthy voltage. This phase shift depends on the impedances and on the power flow. To decide a correct direction, it is useful to "open" the inclination of the characteristic line.

Due to the inaccuracy of the algorithm, the measuring errors caused by the short-circuit transients and the angle error of the measuring transformers, the impedance contains inaccuracy too. In this way, the calculated impedance does not determine a single point on the impedance plane, but points, which can cover a rather large area in the subsequent sampling sequence. The characteristics must include this area as well. Because of the effects mentioned above it is useful to open the characteristics.

The following fact however contradicts to the opening:

The characteristics must exclude the impedance measured in the healthy loops. The separation of the measuring loops based on the zero sequence current can exclude the measured impedance values of some loops, but the remaining impedance values measured in healthy loops can approach the characteristics, especially in case of heavy pre-fault load. An example is a close-in double phase fault, in phases „B” and „C”, when the impedance measured in the healthy loop „AB” is close to the borders of the characteristics. Therefore, it is useful to set the characteristics as closed as possible.

The requirements are in contradiction, an engineering compromise is needed to set the slope based on the experiences. When making these considerations the mentioned VECTOR program of PROTECTA can help identifying the critical situations, and investigating the effect of the actual parameters as well.

This parameter can be calculated as

$$\text{Angle 2nd Quad} = \text{ArcTan} (|R|/X) [\text{deg}]$$

Here the ratio defines the slope only; X and R have no relationship to the positive sequence impedance data of the line. The unit of this parameter is degrees.

For example in case of a 120 kV transmission line the proposed setting is: Angle 2nd Quad =

15 deg. This is the inclination from the X axis 15 deg to the left. The greatest possible opening is 30 deg. If needed, this setting can be modified.

The proposed setting:

$$\text{Angle 2nd Quad} = 15 \text{ deg}$$

This angle is common for all five zones.

R Load

Load Angle

When setting the impedance stages it has to be taken into account that the setting should be well below the impedance measured in maximum power operating condition. If however extremely high (temporary) load can be expected and at the same time the zone reach in R direction is set to a high value then the "load encroachment" property of the distance protection function can help in case of high load, to exclude the measured impedance from the distance characteristic. There are two parameters to serve tightening the characteristic: „R Load“ and „Load Angle“. The effect of these parameters is shown in Figure 1-1. The application of these parameters supposes that the power transfer along the line is mostly active power only. Based on the supposed maximum current (or thermal load limit) in overload operation the load resistance can be calculated

$$R_{load} = \frac{U_{line-to-line,rated}}{\sqrt{3} * I_{oper,max}} = \frac{(U_{line-to-line,rated})^2}{S_{oper,max}}$$

where

$I_{oper,max}$ is the highest possible (overload) current;
 $S_{oper,max}$ is the thermal load limit, three-phase power.

This consideration is especially important in high voltage systems. For the 120 kV example above, the thermal load limit of the line is:

$$S_{oper,max} = 110 \text{ MVA}$$

The calculated resistance in case of max load is:

$$R_{load} = \frac{(U_{line-to-line,rated})^2}{S_{oper,max}} = \frac{(120kV)^2}{110MVA} = 130 \Omega \text{ (primary value).}$$

As compared with the proposed "Zone 1 R" setting = 14.26 Ω this results 130 Ω / 14.26 Ω \square 9 - times margin. Consequently, in case of a relatively long 120 kV line, the load has no influence on the setting of the characteristic parameters.

This primary resistance 130 Ω is to be calculated to the secondary side of the measuring transformers.

$$R_{load \text{ second.}} = ai/au * R_{load \text{ prim.}} = (600/5) / (120/0.1) * 130 \Omega = \underline{13 \Omega}$$

This setting may influence the shape of the characteristic in higher zones and the shape of the characteristic for power swing detection.

For a 200 km long 400 kV line however the proposed setting is:

$$\text{Zone 1 R} = \text{Zone 1 X} = 200 \text{ km} * 0.32 \Omega/\text{km} / (1+0.15) = 55.65 \Omega$$

$$R_{load} = \frac{(U_{line-to-line,rated})^2}{S_{oper,max}} = \frac{(400kV)^2}{1200MVA} = 133 \Omega \text{ (primary value).}$$

133 Ω / 55.65 Ω \square 2.3 - times margin. If large "Zone 1 R" setting value is needed due to the measurement distortion of the fault resistance, then the load resistance can be within the extended characteristic. Consequently, the correct "R load" setting is important.

This primary resistance 133 Ω is to be calculated to the secondary side of the measuring transformers.

If at the relay location also a relatively small amount of reactive power is measured then load encroachment area is "opened" using the „Load Angle“ parameter. The method of calculation is as an example with 20% reactive load:

$$\text{Load Angle} = \text{ArcTan}(Q_{\text{max}}/P_{\text{max}}) = \text{ArcTan}(0.20) = 11.3 \text{ deg} \approx 12 \text{ deg}$$

Zone Reduction Angle

The algorithm of the distance protection calculates fault distance based on the measured reactance value.

If the fault resistance at the fault location cannot be neglected and before fault inception there is considerable power transfer on the protected line the calculated reactance value – consequently the calculated distance to fault - is distorted. This distortion means overreaching (or under-reaching) of the distance protection. Overreaching can result operation also in case of fault outside the protected zone, resulting unselective tripping.

To compensate this distortion of the measured distance the X border line of the polygon-shaped characteristic can be tilted downwards or upwards, depending on the amount and direction of the pre-fault power transfer on the protected line. Figure 1-1 shows tilting downwards, the zone reduction angle is clockwise.

The tilting is performed dynamically in five sections depending on the extent of the pre-fault power transfer. The setting of the tilting angle needs technical consideration. This method of calculation is explained in the Appendix.

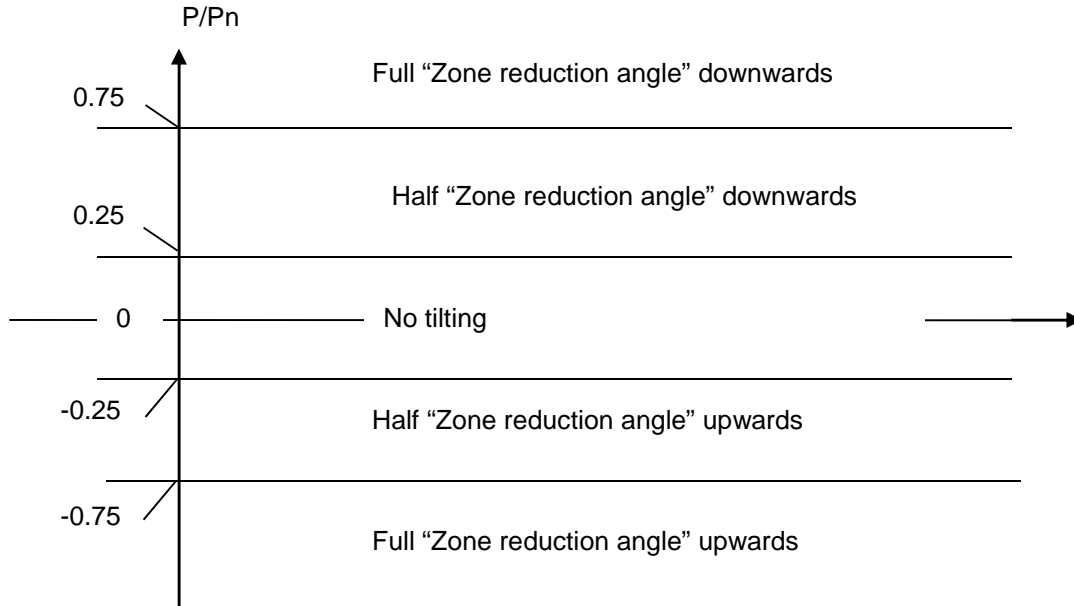


Figure 1-4 Dynamic sections of the "Zone reduction"

The result of this correction is that for fault at the zone reach point, the behavior of the distance protection is practically independent on the pre-fault load state of the protected line or cable.

Zone1 (Xo-X1)/3X1
Zone1 (Ro-R1)/3R1

In case of faults involving the ground, the algorithm applies formulas for the impedance (distance) calculation, where the phase currents are compensated with the zero sequence current.

$$Z = \frac{U_{phase}}{I_{phase} + \alpha \cdot 3I_0}$$

The α zero sequence current compensation factor is applied in the algorithm of the distance protection function in the form of two real factors. Both of them are calculated from the data of the protected line. With the data given above for the 120 kV line:

$$\alpha_x = \frac{(x_0 - x_1)}{3 \cdot x_1} = \frac{(1.03 - 0.41)}{3 \cdot 0.41} = 0.504$$

$$\alpha_r = \frac{(r_0 - r_1)}{3 \cdot r_1} = \frac{(0.3 - 0.12)}{3 \cdot 0.12} = 0.5$$

Accordingly the required setting values are:

$$\text{Zone1 (Xo-X1)/3X1} = 0.5$$

$$\text{Zone1 (Ro-R1)/3R1} = 0.5$$

Note: In some applications the parameters “Zone2 (Xo-X1)/3X1” and “Zone2 (Ro-R1)/3R1” is considered to be equal to those of the Zone1. In this case, this parameter cannot be seen in the group of parameters for the second zone.

Par Line Xm/3X1
Par Line Rm/3R1

In case of asymmetrical fault involving the ground, the zero sequence current of the parallel line influences the impedance measurement. To compensate this effect the zero sequence current of the parallel line is to be measured, and the effect is compensated in the calculation using the zero sequence mutual compensation factors for the parallel line. In the applied algorithm, it is performed in the form of two real factors:

$$\beta_r = \frac{r_m}{3 \cdot r_1}$$

$$\beta_x = \frac{x_m}{3 \cdot x_1}$$

Additionally to the given positive sequence reactance and resistance (See the data of the example above):

$$\text{per unit positive sequence reactance: } x_1 = 0.41 \text{ } \Omega/\text{km}$$

$$\text{per unit positive sequence resistance: } r_1 = 0.12 \text{ } \Omega/\text{km}$$

the data of the mutual per unit impedances are also needed. In this example, they are supposed to be:

$$\text{per unit mutual zero sequence reactance: } x_m = 0.70 \text{ } \Omega/\text{km}$$

$$\text{per unit mutual zero sequence resistance: } r_m = 0.15 \text{ } \Omega/\text{km}$$

With these data:

$$\frac{r_m}{3 * r_1} = \frac{0.15}{3 * 0.12} = 0.42$$

$$\frac{x_m}{3 * x_1} = \frac{0.70}{3 * 0.41} = 0.57$$

Accordingly the required setting values are:

$$\text{Par Line } X_m/3X_1 = 0.57$$

$$\text{Par Line } R_m/3R_1 = 0.42$$

This compensation factor is considered for Zone 1 only.

Zone1 Time Delay

The first stage of the distance protection can be delayed.

The time delay of the first stage is to be set with this parameter in milliseconds. The usual setting is 0, which means no additional time delay; the protection function operates with the "natural" delay of the calculation time.

Operation Zone1

The first stage of the distance protection can be disabled or can be directed forward or backward. The parameter value can be "Off, Forward, Backward", accordingly. The usual setting is forward, supposing that the fault current flows toward the protected line.

Zone1 Start Only

The trip command of the first zone of the distance protection can be inhibited using this parameter. If this Boolean parameter is set to "1" (logic TRUE) then the function is operable, but the trip command is blocked. Set 0 for „Zone1 Start Only“, to generate also a trip command.

PSD Block Z1

The distance protection function includes the embedded function for power swing detection. The role of this embedded function block is – among others – to block the trip command if the measured impedance is within the characteristic of the distance protection not because of fault but due to power swings. If this Boolean parameter is set to "1" (logic TRUE) then the detected power swing state blocks the trip command.

1.1.1.2 Setting the second impedance stage

The second impedance stage is usually delayed with a selective time step. This stage has certainly to operate in case of a fault at a small section on the far end of the line, which is not covered by the first stage. The operation has to be achieved even if the protection measures with a negative error:

$$Z'' \geq \frac{Z_V}{(1-\varepsilon)}$$

Where

Z'' is the setting of the second impedance stage.

If the outgoing lines from the far end busbar are protected with distance protection as well, then the second stage of our protection may not operate together or instead of the second stage of the protection on the shortest outgoing line. No overlapping of the characteristics is allowed, even if the far away protection operates with negative measuring error, and our protection has a positive measuring error:

$$Z'' \leq \frac{Z_V + (1-\varepsilon)Z'_K}{(1+\varepsilon)} = \frac{Z_V + (1-\varepsilon)\frac{Z_K}{(1+\varepsilon)}}{(1+\varepsilon)}$$

Where:

Z'' setting of the second stage,

Z_V positive sequence impedance of the line to be protected,
the security factor, usually 0.15

Z'_K setting values of the far away line distance protection,

Z_K positive sequence impedance of the far away line.

If the far away line is too short, it is possible that the second stage of our protection overlaps the second stage of the following line distance protection. To avoid the non selective trip, the time setting has to be delayed with two selective time steps.

If the busbar at the far end of the line protected supplies a transformer, the second stage of our protection may not overreach the transformer, even if the measuring has a positive error:

$$Z'' \leq \frac{Z_V + Z_{TR}}{(1+\varepsilon)}$$

Z'' second stage impedance setting,

Z_{TR} impedance of the transformer,

Z_V positive sequence impedance of the line to be protected,

ε the security factor, usually 0.15.

The parameters to be set are as follows:

Operation Zone2
Zone2 Start Only
PSD Block Z2
Zone2 R
Zone2 X
Zone2 (Xo-X1)/3X1
Zone2 (Ro-R1)/3R1
Zone2 time delay

See the explanation for setting the first stage.

Note: In some applications the parameters “Zone2 (Xo-X1)/3X1” and “Zone2 (Ro-R1)/3R1” is considered to be equal to those of the Zone1. In this case, this parameter cannot be seen in the group of parameters for the second zone.

The time delay of the second stage is to be set in milliseconds, the value should be usually one selective time step. If however the far away line is too short, it is possible that the second stage of our protection intersects the second stage of the far away line distance protection characteristics. In this case, the time setting is delayed with two selective time steps.

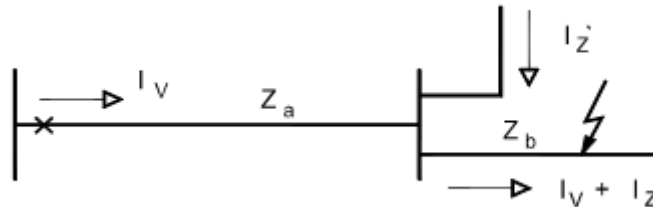


Figure 1-5 Distortion caused by power supply at the far line end

If a fault occurs on a next outgoing line (Figure 1-5), the protection measures a larger impedance than the impedance proportional with the distance, because of the distorting effect of the I_z' short-circuit current component delivered by a third line. The measured impedance will be greater than the real one, which means, that the border of the impedance stage is withdrawn. It is possible that the fault in the second zone and the protection trips only in the subsequent (third) stage, which means an additional time delay.

Setting the second stage as an overreaching stage

Application of overreaching stage with co-operation of an external automatic reclosing device can be effective to overcome the problems caused by the delayed fault clearing in case of faults near the far line end. Another application of overreaching is the “tele-protection” (see Chapter 7.4. in detail). In case of overreaching, the setting will cover completely the protected line, but the faults at the beginning of the outgoing line as well. The formula for setting is:

$$Z^{OVERREACH} \geq \frac{Z_v}{(1 - \varepsilon)}$$

1.1.1.3 Setting the higher impedance stages

The role of these stages of the distance protection is to give back up protection to the following lines outgoing from the far busbar, or reverse backup protection, so it has not a main protection role. Due to the feeding distortion mentioned above (explained with Figure 1-5), this task cannot be fully achieved. Therefore, the most important setting aspect to be considered is to avoid faulty start on high power transmission on the line and on a power swing.

This stages can also serve special purposes (e.g. two second stages with two time delays and setting values in case of short outgoing line from the far away busbar, reverse zones, generation of inhibition signals for some “tele-protection” schemes to detect faults in reverse direction, etc.

Of course, this description cannot cover all network configurations, but the examples above show, that the setting of a protection must be co-ordinated with all other protections of the network. When determining the setting values, a great care must be taken. A too high setting value for the third stage is not advised. The same statement is valid for all higher stages as well.

The time delay of these stages has an additional selective time step.

The parameters for the stages 3, 4, 5 are as follows:

Operation Zone3, 4, 5
Zone3,4,5 Start Only
PSD Block Z3,4,5
Zone3,4,5 R
Zone3,4,5 X
Zone3,4,5 (Xo-X1)/3X1
Zone3,4,5 (Ro-R1)/3R1
Zone3,4,5 time delay

See the explanation for the first stage setting.

The time delay of these stages is given in milliseconds, the value is usually the delay time of the second stage plus at least one selective time step. The value can be determined only knowing the total protection system.

The backward stages can form a natural bus-bar protection for the substation. If the time delay is shorter than that of the distance protection second stage at the far away line end, then the nearest circuit breakers will be disconnected on busbar fault. Since this stage must detect close-in faults as the busbar fault, the impedance setting must be appropriately small. In this role, the impedance setting of the reverse stage can be safely smaller, than the setting of the protection for the shortest line.

1.2 Binary signals influencing the operation of the distance protection function

1.2.1 Binary inputs of the distance function block

The **binary inputs** of the distance protection function block are signals influencing the operation. These signals are the results of the logic schema, graphically edited by the user.

Binary input signals	Signal title	Explanation
DIS21_VTS_GrO_	Block from VTS	Blocking signal due to error in the voltage measurement
DIS21_Z1Blk_GrO_	Block Z1	Blocking of Zone 1
DIS21_Z2Blk_GrO_	Block Z2	Blocking of Zone 2
DIS21_Z3Blk_GrO_	Block Z3	Blocking of Zone 3
DIS21_Z4Blk_GrO_	Block Z4	Blocking of Zone 4
DIS21_Z5Blk_GrO_	Block Z5	Blocking of Zone 5
DIS21_PSDBlk_GrO_	Block PSD	Blocking signal for power swing detection
DIS21_SOTFCond_GrO_	SOTF COND.	Status signal indicating switching-onto-fault condition

Table 1-6 Binary input signals influencing the operation of the distance protection function block

Block from VTS

If there is no voltage for impedance calculation then the distance protection function must be blocked. The blocking signal can be generated from

- the auxiliary contact of the miniature circuit breaker in the voltage transformer secondary circuit, or
- the voltage transformer supervision (VTS) function block.

The application of the auxiliary contact of the miniature circuit breaker in the voltage transformer secondary circuit is shown for common contact in Figure 1-6, for individual auxiliary contacts in Figure 1-7. This mode of application generates a logic TRUE signal, if the contacts are closed. This signal is connected to a binary input of the device.

Another possibility for supervision is the application of the voltage transformer supervision (VTS) function block. See the details in the manual "**Voltage transformer supervision and dead line detection function block description**". Depending on the setting, this function block generates a signal, if the detected asymmetry of the three-phase currents differs from the type of asymmetry measured in the three-phase voltages.

These signals are connected in the graphic logic editor to the VTS input of the distance protection function block (DIS 21). See Figure 1-8.

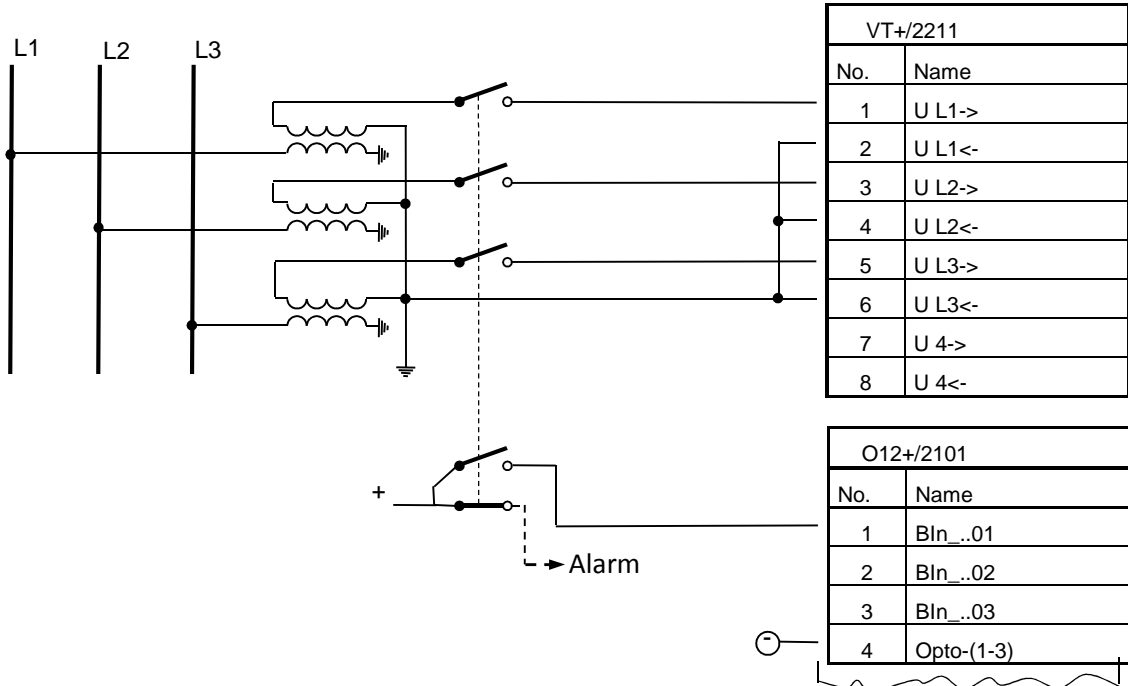


Figure 1-6 Common auxiliary contact for the VT miniature circuit breakers

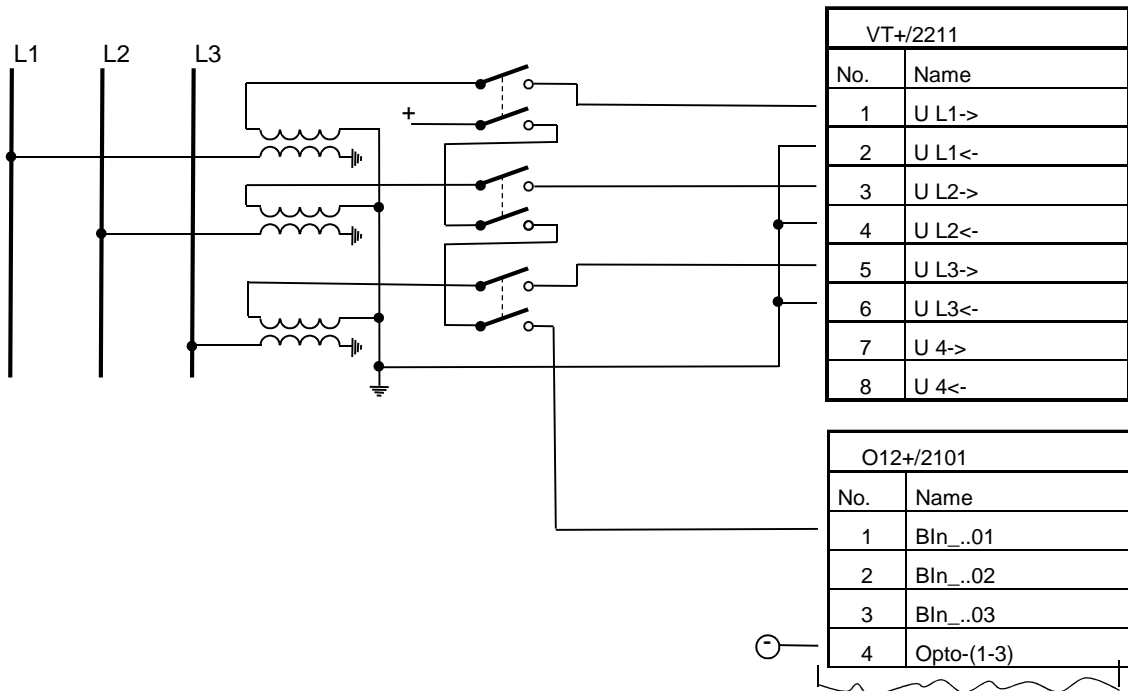


Figure 1-7 Individual auxiliary contacts for the VT miniature circuit breakers

The application of this input is shown in Figure 1-9.

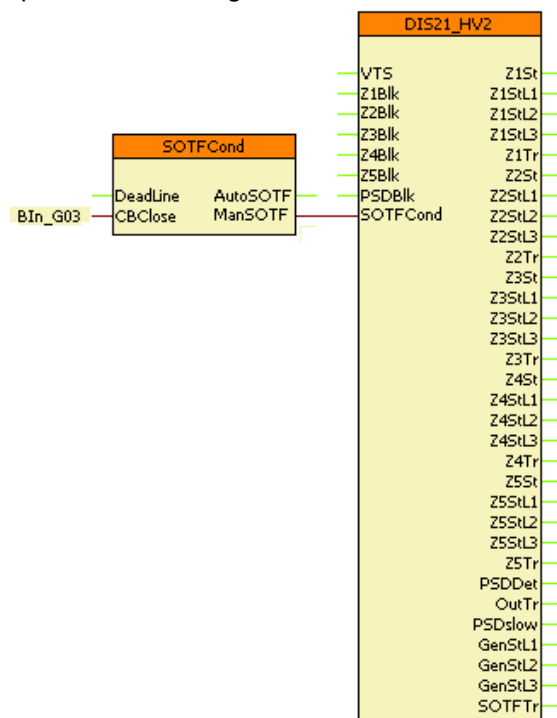


Figure 1-9 Example: Application of the SOTFCond function block (Detail)

1.3 The current conditions of the distance protection function

The distance protection function can operate only if the current is sufficient for impedance calculation. Additionally, a phase-to-ground fault is detected only if there is sufficient zero sequence current. The setting values in this chapter support these preliminary decisions.

1.3.1 The parameters of the current condition

Integer parameters

Parameter name	Title	Unit	Min	Max	Step	Default
Definition of minimal current enabling impedance calculation:						
DIS21_Imin_IPar_	IPh Base Sens	%	10	30	1	20
Definition of zero sequence current characteristic enabling impedance calculation in phase-to-earth loops:						
DIS21_IoBase_IPar_	IRes Base Sens	%	10	50	1	10
DIS21_IoBias_IPar_	IRes Bias	%	5	30	1	10

Table 1-7 Integer parameters for the current conditions module

The current is considered to be sufficient for impedance calculation if it is above the level set by parameter “IPh Base Sens”.

To decide the presence or absence of the zero sequence current, biased characteristics are applied (see Figure 1-10). The minimal setting residual current (IRes Base Sens.) and a percentage biasing IRes Bias must be set. The biasing is applied for the detection of residual current in the case of increased phase currents.

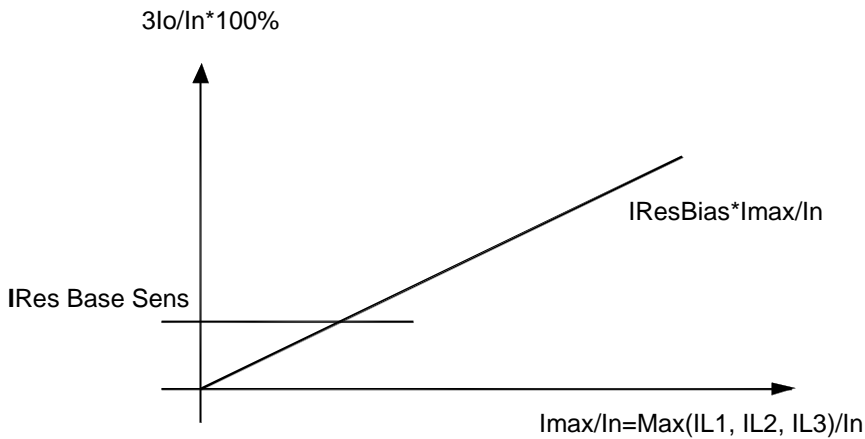


Figure 1-10 Percentage characteristic for earth-fault detection

1.3.2 Setting the zero sequence current detection

The zero sequence current detection is needed to separate earth faults and faults without earth contact. This separation prevents for example that in case of close-in A-N phase-to-earth fault the measured impedance in the phase-to-phase loops CA or AB could disturb correct decision. If considerable zero sequence current is detected, then the results calculated for phase-to-phase loops are not taken into consideration. Another example can be a fault between phases B and C, when small impedance is detected in phase-to-earth loops B-N and C-N as well, but in case of BC fault, there is no zero sequence current, so the measured values for phase-to-earth loops can be excluded from the decision.

To decide the presence or absence of the zero sequence current, biased characteristics are applied which avoid starting on phase-to-phase faults with high current. The minimal setting current (IRes Base Sens) and a percentage biasing (IResBias) is to be set (See Figure 1-11).

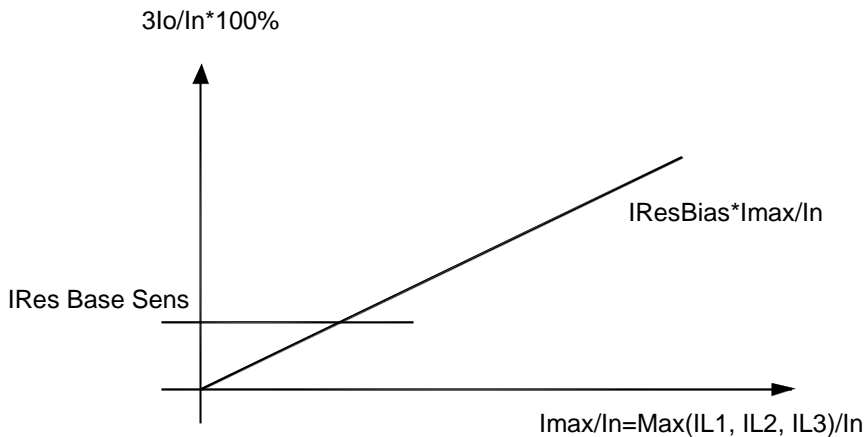


Figure 1-11 Zero sequence current detection with biased characteristics

IRes Base Sens

The correct setting needs the following considerations:

The zero sequence current detection setting should be sensitive enough to detect the smallest possible zero sequence current in case of a phase-to-earth fault or a double phase-to-earth fault. The selectivity is needed mainly in case of faults in the base zone, which is the first stage and the second stage of the distance protection, i.e. the line to be protected. So the smallest zero sequence current must be determined with a series of short-circuit calculations. It is necessary to calculate faults in the reverse zone as well.

The setting value is limited by the zero sequence currents, which can be detected in case of faults without earth. Principally there are no zero sequence currents in these kinds of faults; even so, zero sequence current can be detected. They are caused for example by the current and phase errors of the current transformers, by the saturation differences between the phase CT-s, and by the zero sequence error currents due to the asymmetrical arrangement of network elements as well.

Usually, the two considerations above do not cause any difficulties in setting. The setting range is 10-50 % of the current transformer rated value.

IRes Bias

The biasing is needed, because the errors of the current transformers increases with increasing phase currents on fault. The setting range is 5-30 % of the current transformer rated value.

1.3.3 Setting the starting current to limit line impedance calculation

The impedance cannot be calculated with the required accuracy if the current value is too low. To avoid errors, limit current is to be set as follows:

IPhBase Sens

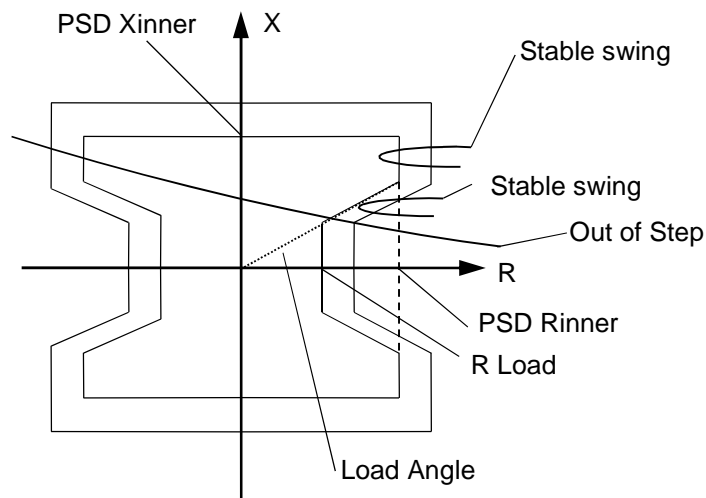
Based on experiences the factory setting of this parameter usually assures correct operation of the function.

1.4 The embedded function block for power swing detection (PSD)

On a relatively long transmission line, the power swings can result low voltage and high current values. Consequently, the distance protection function can measure low impedance, which is inside the tripping characteristic. To avoid the trip command, the power swing detection function can be applied.

Power swings can be stable or they can result in an out-of-step operation. Accordingly, the power swing detection function can block the distance protection function in case of swings. This function can also generate a trip command if the system operates out of step (See Figure 1-12).

1.4.1 The parameters for power swing detection



Ratio of the outer characteristics related to the inner one is set by:

PSD R_{out}/R_{in}

PSD X_{out}/X_{in}

The load encroachment setting for the polygon inside is the same as for the distance characteristic:

R Load

Load Angle

The polygon outside can be calculated by shifting the load encroachment points parallel to the „R” axis, by the ratio

PSD R_{out}/R_{in}

Figure 1-12 Characteristics of the power swing detection function

The **parameters** of the power swing detection function are explained in the following tables.

Enumerated parameters

Parameter name	Title	Selection range	Default
Parameters for power swing detection (with out-of-step detection) concerning the number of the involved phases:			
DIS21_PSD_EPar_	Operation PSD	Off, 1 out of 3, 2 out of 3, 3 out of 3	1 out of 3
Parameter enabling “out-of-step” function:			
DIS21_Out_EPar_	Oper. OutOfStep	Off, On	Off

Table 1-8 The enumerated parameters of the power swing detection function

Boolean parameters for the individual zones to be blocked by the Power Swing Detection (PSD) function:

Parameter name	Title	Default	Explanation
DIS21_PSDBlk1_BPar_	PSD Block Z1	0	1 for Zone1 to be blocked by PSD
DIS21_PSDBlk2_BPar_	PSD Block Z2	0	1 for Zone2 to be blocked by PSD
DIS21_PSDBlk3_BPar_	PSD Block Z3	0	1 for Zone3 to be blocked by PSD
DIS21_PSDBlk4_BPar_	PSD Block Z4	0	1 for Zone4 to be blocked by PSD
DIS21_PSDBlk5_BPar_	PSD Block Z5	0	1 for Zone5 to be blocked by PSD

Table 1-9 The Boolean parameters of the distance protection function

Floating point parameters

Parameter name	Title	Dim.	Min	Max	Default
X and R setting of the internal rectangle of the characteristics:					
DIS21_Xin_FPar	PSD Xinner	ohm	0.1	200	10
DIS21_Rin_FPar	PSD Rinner	ohm	0.1	200	10

Table 1-10 The floating-point parameters of the power swing detection function

Integer parameters

Parameter name	Title	Unit	Min	Max	Step	Default
Definition of the ratio of the outside and inside rectangles of the characteristics for power swing detection:						
DIS21_RRat_IPar_	PSD R_out/R_in	%	120	160	1	130
DIS21_XRat_IPar_	PSD X_out/X_in	%	120	160	1	130

Table 1-11 The integer parameters of the power swing detection function

Timer parameters

Parameter name	Title	Unit	Min	Max	Step	Default
DIS21_PSDDel_TPar_	PSD Time Delay	ms	10	1000	1	40
DIS21_PSDSlow_TPar_	Very Slow Swing	ms	100	10000	1	500
DIS21_PSDRes_TPar_	PSD Reset	ms	100	10000	1	500
DIS21_OutPs_TPar_	OutOfStep Pulse	ms	50	10000	1	150

Table 1-12 The timer parameters of the power swing detection function

1.4.2 Setting

Operation PSD

The power swing is usually a three-phase phenomena, but in special application, the line can operate also when one phase is switched off. Set this parameter according to the application (1 out of 3, 2 out of 3, 3 out of 3), or using this parameter, the blocking of the distance protection can be disabled (Off).

Example: when the selection is “3 out of 3” then all three phase-to-ground measuring loop is required to detect power swing to block the distance protection.

Oper. OutOfStep

The out-of step detection is a “by-product” of the function. If the power swing is not asymptotic to a final load angle, but the voltage on one end of the protected line continuously revolves as

compared to the voltage at the other end, then this function generates a status signal. This signal can be enabled (On) or disabled (Off), using this parameter.

PSD Block Z1

If this Boolean parameter is set to logic TRUE (1) then the detected power swing blocks the trip command of Zone1.

PSD Block Z2

PSD Block Z3

PSD Block Z4

PSD Block Z5

These parameters have the same effect to higher zones as the parameter “PSD block Z1” to Zone 1.

Note: Consider that higher zones have usually high time delay setting (500 ... 2500 ms). The slowest power swing in a stable network is not lower than 2 Hz. It means that the impedance within 500 ms performs a whole period of the swing, consequently the trajectory of the impedance leaves the impedance zone again; the timer of the impedance zone cannot reach the tripping state. Consequently, these zones need not be involved in power swing blocking.

PSD Xinner

PSD Rinner

These parameters define characteristic of power swing detection. See Figure 1-12.

The required setting of these parameters is in close relationship with the selection “PDS Block_x”. These values should be set higher than the setting of the selected impedance zones. Example: if the Zone 3 has the highest impedance setting among the zones to be blocked by the power swing, then the recommended setting is:

$$\begin{aligned} \text{PSD Xinner} &> k_x * \text{Zone3 X} \\ \text{PSD Rinner} &> k_r * \text{Zone3 R} \end{aligned}$$

Where Zone3 X is the X setting for Zone3
 Zone3 R is the R setting for Zone3
 k_x is a security factor in X direction, at least 1.2
 k_r is a security factor in R direction. This factor should be selected high enough to exclude the upper right corner (in this example) of the Zone 3 distance characteristic.

Example:

Zone3 R = 15 Ohm

Zone3 X = 10 Ohm

Line Angle = 73°

$$\begin{aligned} \text{PSD Rinner} &= 1.2 * (\text{Zone3 R} + \text{Zone3 X} * \text{ctg}(\text{Line Angle})) \\ &= 1.2 * (15 \text{ Ohm} + 10 \text{ Ohm} * \text{ctg}(73^\circ)) = 21.67 \text{ Ohm} \square 22 \text{ Ohm} \\ \text{PSD Xinner} &= 1.2 * 10 \text{ Ohm} = 12 \text{ Ohm} \end{aligned}$$

PSD R_out/R_in

PSD X_out/X_in

These two parameters, with the parameters “PS Rinner” and “PSD Xinner” define an impedance band. The time, needed for the measured impedance to pass this band is decisive for the power swing detection. If this time is short then a fault is detected; the trip command may not be blocked. If however, the time is above the “PSD Time Delay” setting, then power swing is detected, the trip command is blocked.

Consequently, these parameters have to be considered together with the parameter “PSD Time Delay”.

PSD Time Delay

This timer parameter is related with the time, which is needed for the measured impedance to pass the defined impedance band. If the measured time is longer than this parameter value then the power swing state blocks the trip command. If the time is shorter, which means that the measured impedance “jumps” inside the characteristic, the fault is detected, and trip command can be generated.

PSD Reset

The setting of this parameter has two functions:

- Extending the duration of the blocked state.
- Limiting the duration of the “Very Slow” state signaling.

The power swing is expected either to return to a stable state of the system, or the continuous change of the angle between the voltages results out-of-step operation of the systems at both line ends. In both cases, the measured impedance leaves the characteristics, defined by the outer characteristic lines. At the moment of leaving the band, a timer is started, which runs for the time defined by this parameter. This means that the blocking state is kept additionally for “PSD Reset” time.

The other allocation of this parameter is explained below.

Very Slow Swing

In heavily loaded state of the electric power system, there is a chance that the measured impedance is within the power swing characteristic band for a long time. To prevent continuous blocking there are two methods available.

One method is that the load encroachment characteristic, set by the parameters “R Load” and “Load Angle”, discloses the impedances measured in heavily loaded state of the electric power system.

The other method is that this parameter limits the duration of the blocked state. At the moment of power swing is detection, a timer starts. If the impedance vector is continuously within the power swing detection characteristics, this timer runs for the time defined by this parameters and then “Slow Swing” is detected. At the same time, the blocking state is reset.

Set this parameter to cover the expected longest swing time period only.

OutOfStep Pulse

This parameter defines the duration of the pulse indicating out-of-step operation of the systems at both line ends.

1.5 The distance-to-fault calculation (**FAULT LOCATOR**)

The distance protection function selects the faulty loop impedance (its positive sequence component) and calculates the distance to fault based on the measured positive sequence reactance and the total reactance of the line. This reference value is given as a parameter setting "Line Reactance". The calculated percentage value facilitates displaying the distance in kilometers if the total length of the line is correctly set by the parameter "Line Length".

1.5.1 The parameters for distance-to-fault calculation

Floating point parameters

Parameter name	Title	Dim.	Min	Max	Default
DIS21_Lgth_FPar_	Line Length	km	0.1	1000	100
DIS21_LReact_FPar_	Line Reactance	ohm	0.1	200	10

Table 1-13 The floating point parameters

1.5.2 Setting

Example for setting the line data

For the setting procedure, the following data are necessary:

Data:

120 kV overhead line,
length:

length = 40 km

per unit positive sequence reactance: $x_1 = 0.41 \Omega/\text{km}$

voltage transformer turns ratio: $au = 120 \text{ kV}/0.1 \text{ kV}$

current transformer turns ratio: $ai = 600 \text{ A} / 5 \text{ A}$

Calculation:

Line Length

Set Line Length = 40 km.

Line Reactance

The primary reactance to be set:

$$X_{\text{prim.}} = \text{length} * x_1 = 40\text{km} * 0.41 \Omega/\text{km} = 16.4 \Omega$$

Transformed to secondary value:

$$X_{\text{second.}} = ai/au * X_{\text{prim.}} = (600/5) / (120/0.1) * 16.4 \Omega = 1.64 \Omega$$

The value to be set:

$$\underline{\text{Line Reactance}} = X_{\text{second.}} = 1.64 \Omega$$

1.6 The high-speed overcurrent protection function with switch-onto-fault logic (**HSOC SOTF**)

The switch-onto-fault protection function can generate an immediate trip command if the function is enabled and switch-onto-fault condition is detected. The condition of the operation can be the starting signal of any distance protection zone as it is selected by a dedicated parameter, or it can be the operation of the high-speed overcurrent protection function.

The high-speed overcurrent protection function operates if a sampled value of the phase current is above the setting value.

1.6.1 The parameters for the switch-onto-fault logic

The parameters of the SOTF function are explained in the following tables.

Enumerated parameters

Parameter name	Title	Selection range	Default
Parameter for selecting one of the zones or "high speed overcurrent protection" for the "switch-onto-fault" function:			
DIS21_SOTFMd_EPar_	SOTF Zone	Off,Zone1,Zone2,Zone3,Zone4,Zone5 ,HSOC	Zone1

Table 1-14 The enumerated parameters of the SOTF function

Integer parameters

Parameter name	Title	Unit	Min	Max	Step	Default
Definition of the overcurrent setting for the switch-onto-fault function, for the case where the DIS21_SOTFMd_EPar_ (SOTF Zone) parameter is set to "HSOC":						
DIS21_SOTFOC_IPar_	SOTF Current	%	10	1000	1	200

Table 1-15 The integer parameters of the SOTF logic

1.6.2 Setting

The general condition to generate a trip command in case of switch onto fault is that the dedicated input "SOTF COND" of the distance protection function block should be active. This signal indicates that in dead state a close command is performed. See Chapter 1.2, and an example in Figure 1-9. The second condition is that additionally a fault is detected. The fault can be detected by any of the distance protection zones or by the high-speed overcurrent (HSOC) function. The selection is the user's choice with setting the "SOTF Zone" parameter.

SOTF Zone

This parameter selects either one of the distance protection zones or the high-speed overcurrent protection function.

When selecting a distance zone (e.g. "Zone3", see Table 1-14) then the additional condition for the trip command is the start signal of this zone. For the decision, the directional parameter of this zone is considered "NonDirectional" independently on the setting (See Table 1-1).

When selecting "HSOC" then the additional condition for the trip command is the operation of the embedded function "HSOC". This high-speed overcurrent protection function operates within one network period, if the measured current is above the setting value "SOTF Current".

SOTF Current

Set this current safely above the highest load current, considering the possible inrush currents in healthy operation, but possibly below the lowest short-circuit current, which can be expected after a close command. No time delay setting is applied.

1.7 Setting in some special applications

1.7.1 Setting for a transmission line with more than two terminals

If the line connects more than two substations, then the setting of the first stage of the protection at busbar “A” in Figure 1-13 should be based on the shortest distance of AC or AB. If the shortest distance is AB then the setting is:

$$Z_A^I = \frac{Z_{AB}}{1 + \varepsilon}$$

As the protection cannot measure the exact distance between “A” and the fault in case of fault between T and C, due to the problem caused by the feeding distortion of the intermediate third supply, the setting of the second stage must be accordingly longer.

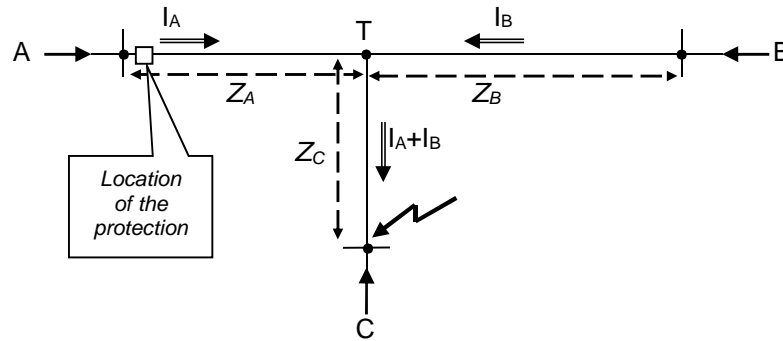


Figure 1-13 Distance measurement on lines with three terminals

According to Figure 1-13 the measured impedance is:

$$Z_{measured} = Z_A + \frac{I_A + I_B}{I_A} Z_C$$

This value is higher than the impedance $Z_A + Z_C$ proportional with the distance. The correct impedance setting for the second zone is:

$$Z_A^{II} \geq \frac{Z_{measured}}{1 - \varepsilon} = \frac{1}{1 - \varepsilon} \left(Z_A + \frac{I_A + I_B}{I_A} Z_C \right)$$

Here the highest possible feeding distortion factor $\frac{I_A + I_B}{I_A}$ on different network conditions must be considered.

1.7.2 Distortion caused by parallel lines

If two line systems are mounted on the same tower, then the zero sequence current flowing in the parallel line, through the zero sequence inductive coupling will result zero sequence induced voltage in the line to be protected. This induced voltage will distort the measured impedance in case of earth faults. The direction of the induced voltage in the protected line depends on the zero sequence current direction on the parallel line.

The smallest possible impedance measured in case of fault at the end of the line must be determined, and the first stage of the differential protection must be set accordingly:

$$Z^I \leq \frac{Z_{meas._min}}{(1 + \varepsilon)}$$

It is a smaller value than the needed setting without parallel effect.

The highest impedance must be similarly determined, and the setting of the second stage of the differential protection is to be set as follows:

$$Z^{II} \geq \frac{Z_{meas._max}}{(1 - \varepsilon)}$$

It is a higher value than the needed setting without parallel effect.

As the second stage in case of measured $Z_{meas._min}$ may reach far into the next line, the time delay must be increased if necessary by two selective time steps. The disadvantage of the additional time delay can be avoided using a “teleprotection” scheme, whose result is quick fault clearing along the protected line.

As an option, the zero sequence current compensation for parallel lines can be considered. If so the current flowing in the parallel line must be connected to the dedicated input of the device, and the parameters β_R and β_L must be set accordingly (See section 1.1.1.1).

2 Appendix: Compensation of the distance distortion due to the power transfer and the fault resistance

The algorithm of the distance protection calculates the fault distance based on the measured reactance value.

If the fault resistance at the fault location cannot be neglected and before fault inception there is considerable power transfer on the protected line then the calculated reactance value – consequently the calculated distance to fault - is distorted. This distortion means overreaching (or underreaching) of the distance protection. Overreaching can result operation also in case of fault outside the protected zone, resulting unselective tripping.

To compensate this distortion of the measured distance the X border line of the polygon-shaped characteristic can be tilted downwards or upwards, depending on the amount and direction of the pre-fault power transfer on the protected line. The angle value of tilting needs technical consideration. This method of calculation is explained below.

2.1 Calculation for three-phase fault

For the calculation the power system is reduced to two points; the protected line is located between these points, fed by two equivalent generators. The calculation is performed with the application of the superposition. The following two components are superposed:

- The first component is the pre-fault steady state, where the pre-fault voltage at the fault location is calculated.
- The fault is added by connection the pre-fault voltage multiplied by (-1) at the fault location of the deactivated network.

The sum of the two components results the faulty state during power transfer on the line.

The superposed results of the calculation result the voltages and currents at the location of the protection. These values are substituted in the measuring equations of the distance protection algorithm.

When comparing the “measured” impedance with the impedance of the protected line, the distortion can be evaluated. This distortion is to be compensated by “tilting” the reactance line of the distance protection.

When explaining the method of calculation below the several influencing factors can also be evaluated.

To derive the information for practical purposes a software is prepared for fault simulation. The diagrams published in this description are the results calculated by this simulation software.

2.1.1 Model of the pre-fault power transfer

The model with the parameters is shown in Figure 2-1.

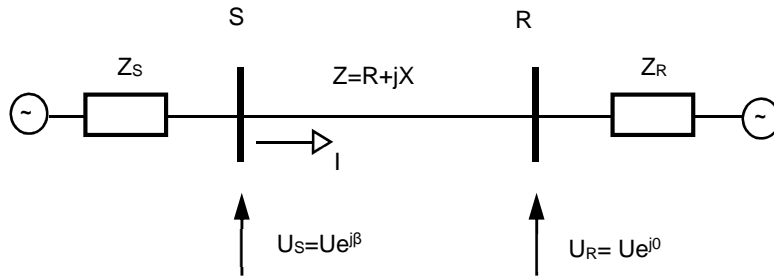


Figure 2-1 Model of the pre-fault power transfer

In this model, the reference voltage is the voltage of the R (receiving) end of the protected line. Here:

$$U_R = \frac{U_N}{\sqrt{3}}$$

This R point will be the fault location. The protection is located at the S (sending) line end.

In the pre-fault steady state, the power transfer can be calculated using the following simplified formula:

$$P = \frac{U^2}{X} \sin(\beta)$$

(Note: When calculating with line-to-line voltages, the power is the three-phase power; substituting phase-to-ground voltages, the single-phase power is calculated.)

The approximation of this formula is neglecting the power loss of the line, but this approximation is acceptable.

The “X” reactance is measured between two points, where the voltage angle difference between them is “ β ”. In some calculation, these two points are the internal points of the equivalent Thevenin generators. In this application however, these points are the R and S ends of the line, the “X” reactance is consequently the reactance of the line.

Another approximation can be to consider the magnitude of the voltages at both line ends to be the same. Consequently, the power transfer is determined by the β angle only.

When substituting a given power the required β angle is:

$$\beta = \frac{\arcsin PX}{U^2}$$

If the reference voltage is the R side voltage then the voltage at the S line end (this is the pre-fault voltage at the relay location) is:

$$U_S = Ue^{j\beta}$$

At this location the pre-fault current is:

$$I_S = \frac{U[(e^{j\beta} - 1)]}{Z}$$

2.1.2 Modeling a three-phase fault component

For the simple explanation, let us start with a three-phase fault. The second component of the superposition is calculated using the schema of Figure 2-2.

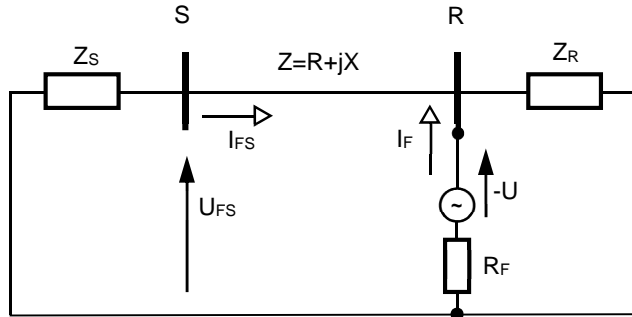


Figure 2-2 Model for three-phase fault component calculation

Seen from the fault location the resulting impedance of the network is:

$$Z_e = \frac{(Z_s + Z) * Z_R}{Z_s + Z + Z_R} + R_F$$

The current at the fault location is:

$$I_F = \frac{-U}{Z_e}$$

The fault current component at the relay is calculated by current division:

$$I_{FS} = I_F \frac{Z_R}{Z_s + Z + Z_R}$$

The fault voltage component at the relay location is:

$$U_{FS} = 0 - Z_s * I_{FS}$$

2.1.3 The superposition for three-phase fault

With summation of the two components calculated above, the voltage and the current measured by the relay are:

$$U_{FProt} = U_s + U_{FS}$$

$$I_{FProt} = I_s + I_{FS}$$

2.1.4 Impedance calculation

It is well known that in case of a three-phase fault, in all six measuring loop the result of the calculation is the positive sequence impedance of the line between the relay and the fault location. Let us select the L1-N loop. Here:

$$Z_{Prot} = \frac{U_{FProt}}{I_{FProt} + komp * 3I_0} = R_{Prot} + jX_{Prot}$$

The zero sequence current compensation factor would be:

$$komp = \frac{Z_0 - Z_1}{3 * Z_1}$$

In case of a three-phase fault however the zero sequence current component is $I_0 = 0$.

When drawing the impedance of the line and the calculated impedance in the same coordinate system, the distortion of the impedance can be evaluated and the required tilting of the characteristic with a θ angle to compensate the distortion can be seen. See Figure 2-3.

$$\theta = \arctg \frac{X - X_{Prot}}{R_{Prot} - R}$$

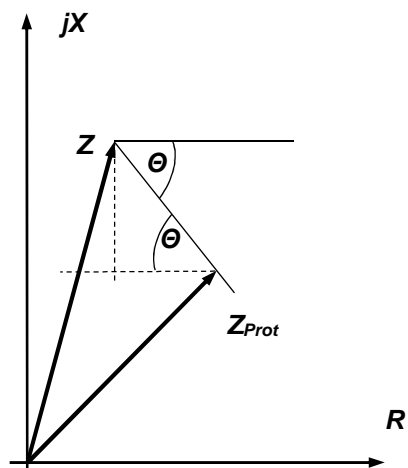


Figure 2-3 Distortion of the measured impedance

2.2 Calculation example

The example below shows the method of calculation for a three-phase fault.

The data of the network correspond to a 400 kV transmission line. These can be identified on the screenshot of the simulation software in Figure 2-4.

The screenshot shows that the angle between the voltages at the line ends is 25° (Beta) which results 995 MW pre-fault power transmission. If in this state the fault resistance is 10 ohm then the required tilting of the X characteristic line is -27.64° (Theta).

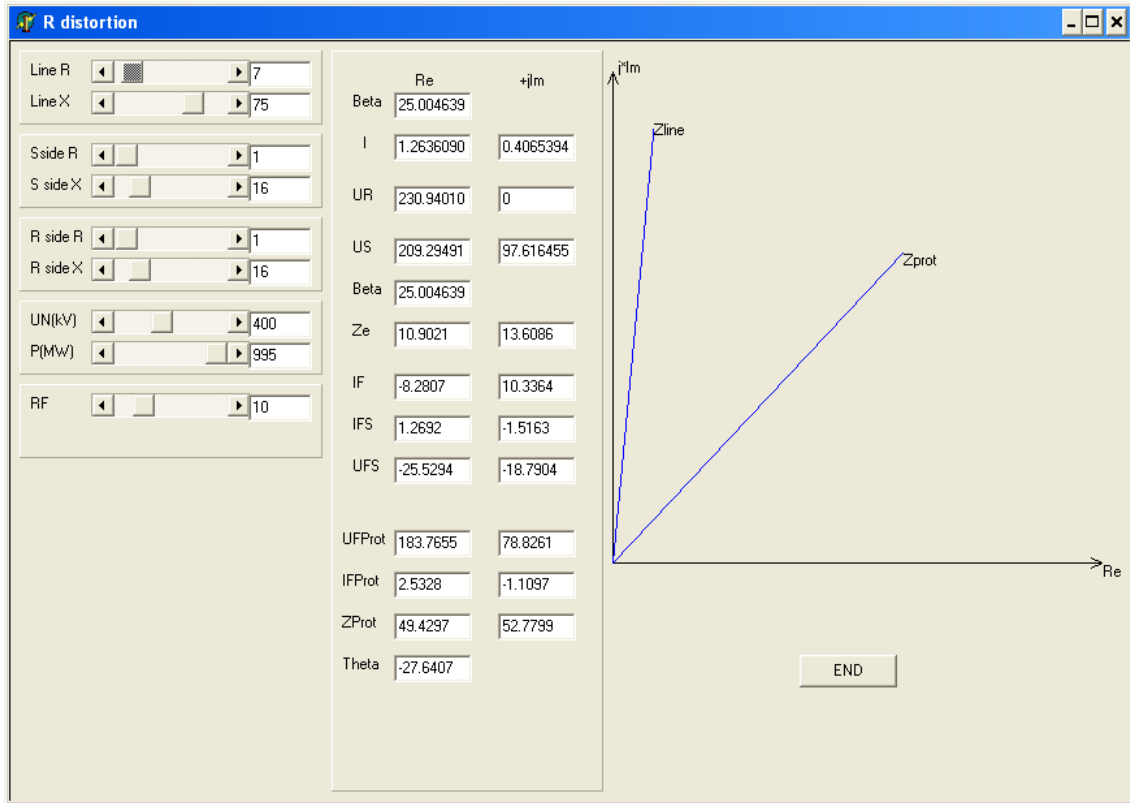


Figure 2-4 Screenshot of the simulation software for three-phase fault

When operating the sliders in the simulation software, the influence of different factors can be studied, and as a result, diagrams can be drawn. The Table and the diagrams below show examples.

							P(MW)	Average
RF(Ohm)	0	10	20	30	40	50		
Beta(°)	(°)	(°)	(°)	(°)	(°)	(°)		(°)
0	1.23	1.23	1.23	1.23	1.23	1.23	0	1.23
5	7.31	7.34	7.38	7.41	7.43	7.45	187	7.386667
10	13.32	12.97	12.66	12.44	12.21	12.05	377	12.60833
15	19.24	18.16	17.32	16.71	16.24	15.58	572	17.20833
20	25.09	23.04	21.57	20.59	19.86	19.32	777	21.57833
25	30.84	27.64	25.53	24.14	23.21	22.5	995	25.64333

Figure 2-5 Calculated results for three-phase fault

Based on the calculated results the following diagram can be drawn. See Figure 2-6.

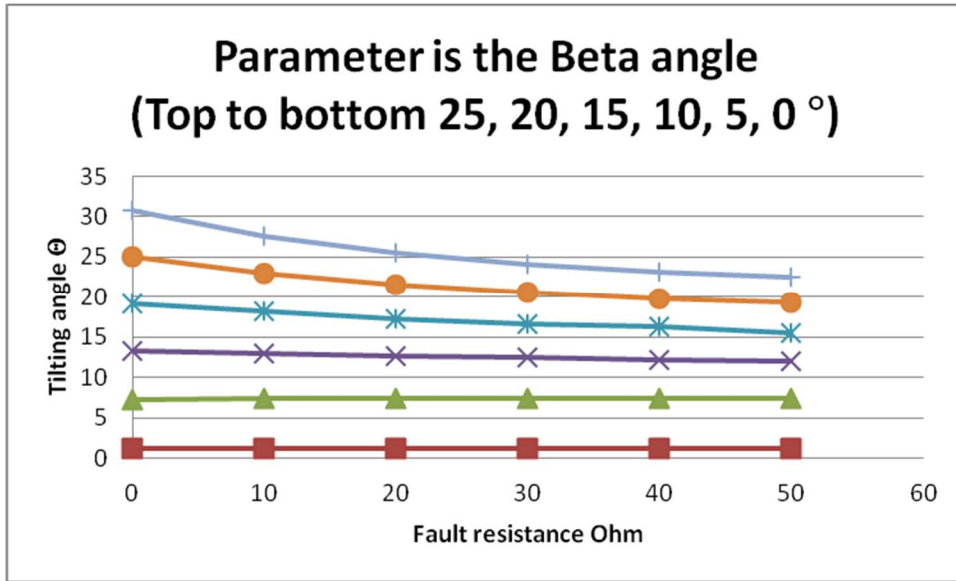


Figure 2-6 Diagram for three-phase fault

Figure 2-6 shows that the required tilting angle changes relatively small in the function of the fault resistance. Consequently, it is justified to calculate the average value for each Beta angle, and to draw a diagram, which shows this average value as the function of the Beta angle. This diagram is shown in Figure 2-7.

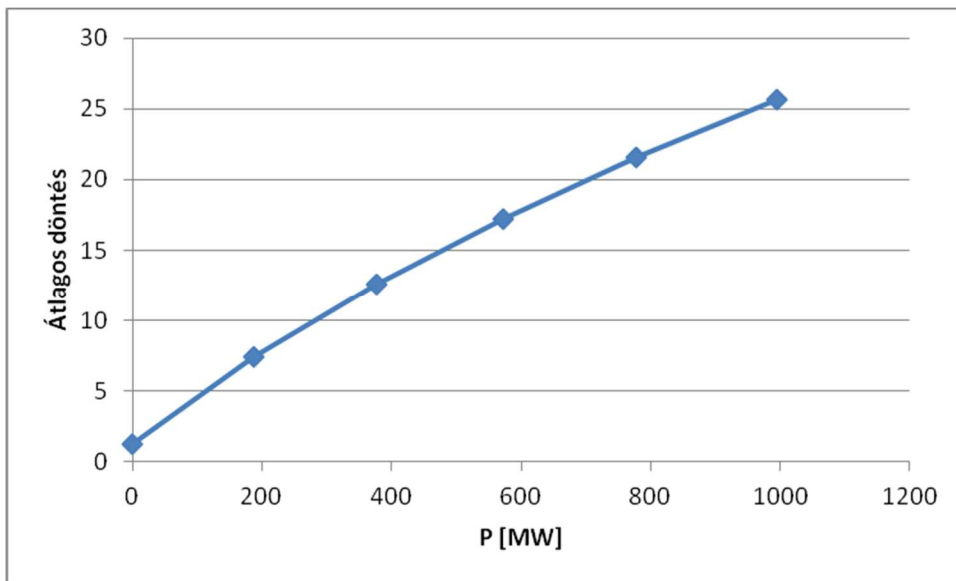


Figure 2-7 Average tilting angle for three-phase fault

When setting the required tilting angle in the parameter set of the protection, the maximum angle calculated for the “rated” power can be selected. In case of moderate power transfer, the algorithm proportionally decreases (in 3 steps) the actual tilting angle. For reverse power direction, however the slope of the X characteristic line is positive, increasing the operating area of the impedance plane.

2.3 Influence of asymmetrical faults

This chapter discusses a single phase to ground fault to find general conclusions.

2.3.1 Modeling a the pre-fault component

The pre-fault power transfer does not depend on the type of fault. Consequently, the first component of the superposition is the same as described in Chapter 2.1.1.

2.3.2 Modeling a single-phase-to-ground fault component

The schema for calculation of the second component of the superposition is shown in Figure 2-8.

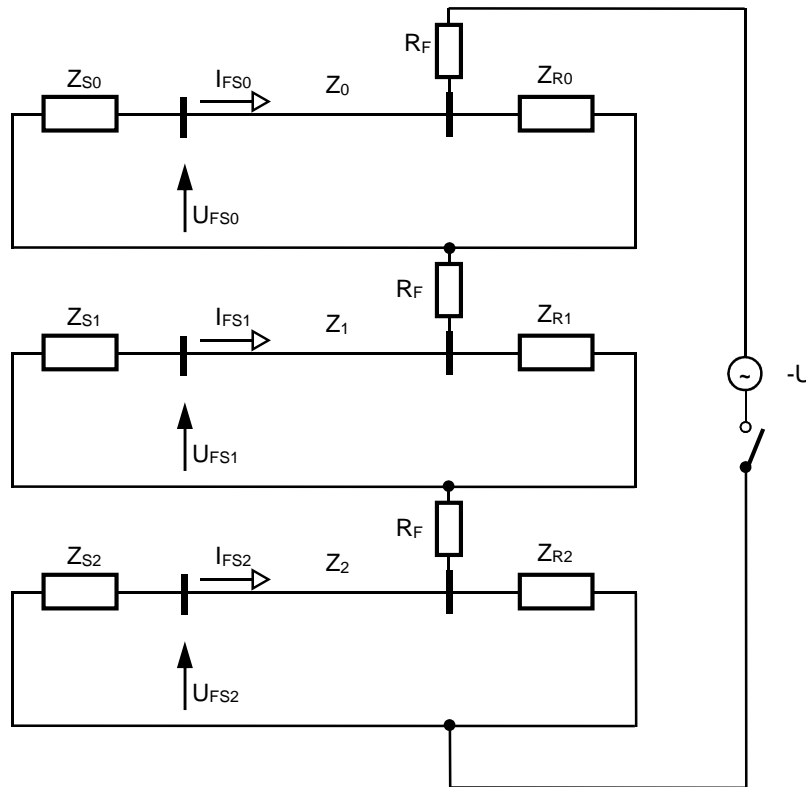


Figure 2-8 Model for single-phase fault component calculation

This model includes the inactivated positive, negative and zero sequence network equivalents in serial connection via R_F fault resistance. Based on this schema the procedure of the calculation is as follows:

- Calculate the resulting impedances of the symmetrical component networks;
- Calculate the positive, negative and zero sequence current component on the fault location;
- Calculate the component currents at the relay location;
- Calculate the component voltages at the relay location;
- Calculate the phase currents at the relay location;
- Calculate the phase voltages at the relay location.

2.3.3 The superposition

The superposition means in this case adding the pre-fault voltages and currents and the single-phase-to-ground fault voltages and currents at the relay location.

2.3.4 Impedance calculation

In the formula for impedance calculation, in the phase-to-ground fault loop the superposed voltage and current is substituted (including the zero sequence current compensation) to calculate the fault impedance.

2.4 Calculation example

The example below shows the method of calculation for a phase-to-ground fault.

The data of the network correspond to a 400 kV transmission line with the modification that the zero sequence impedances are supposed to be identical with the positive sequence impedances. These can be identified on the screenshot of the simulation software in Figure 2-9.

The screenshot shows that the angle between the voltages at the line ends is 25° (Beta) which results 995 MW pre-fault power transmission. If in this state the fault resistance is 10 ohm then the required tilting of the X characteristic line is -27.64° (Theta). This is the same as the result for three-phase fault.

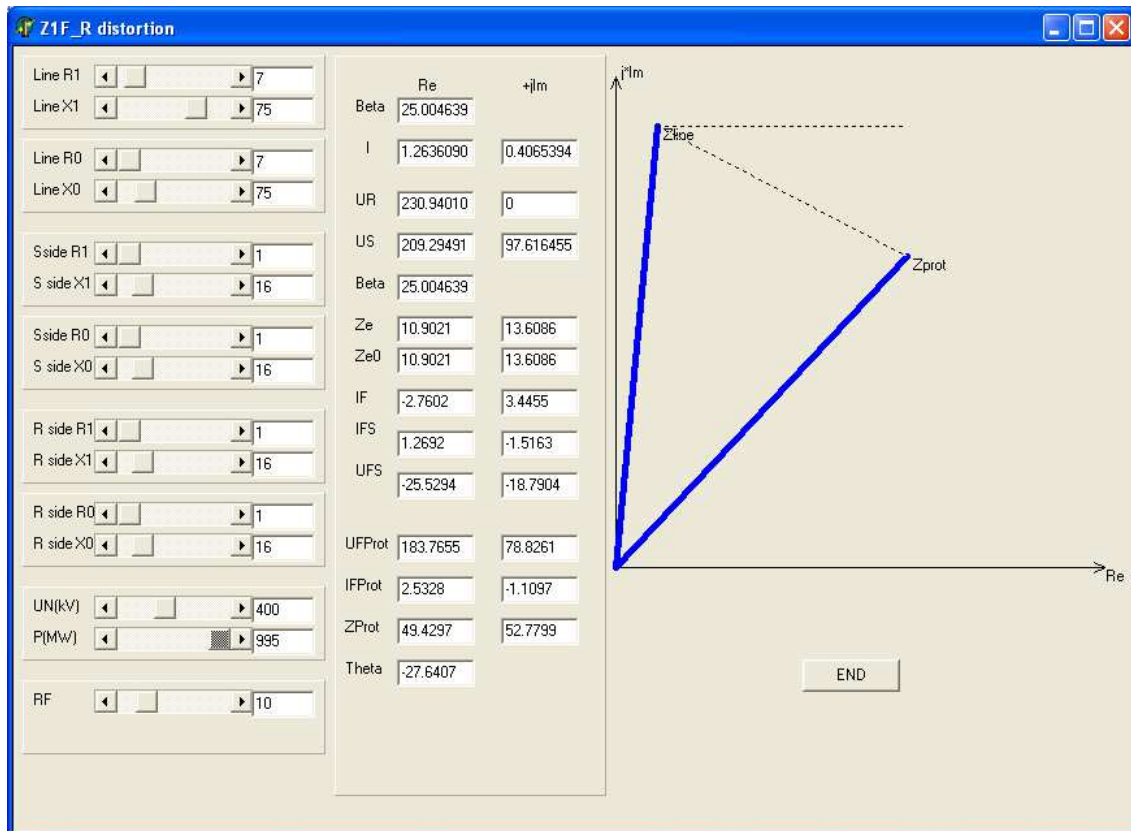


Figure 2-9 Screenshot of the simulation software for phase-to-ground fault

If data that are more realistic are set, (the zero sequence impedance is four times positive sequence impedance) then the results slightly deviate.

In the example below with 25° voltage angle (Beta) the power transfer is 995 MW. A 10 ohm fault resistance results the need of -26.79° (Theta) tilting of the X characteristic line. See Figure 2-10.

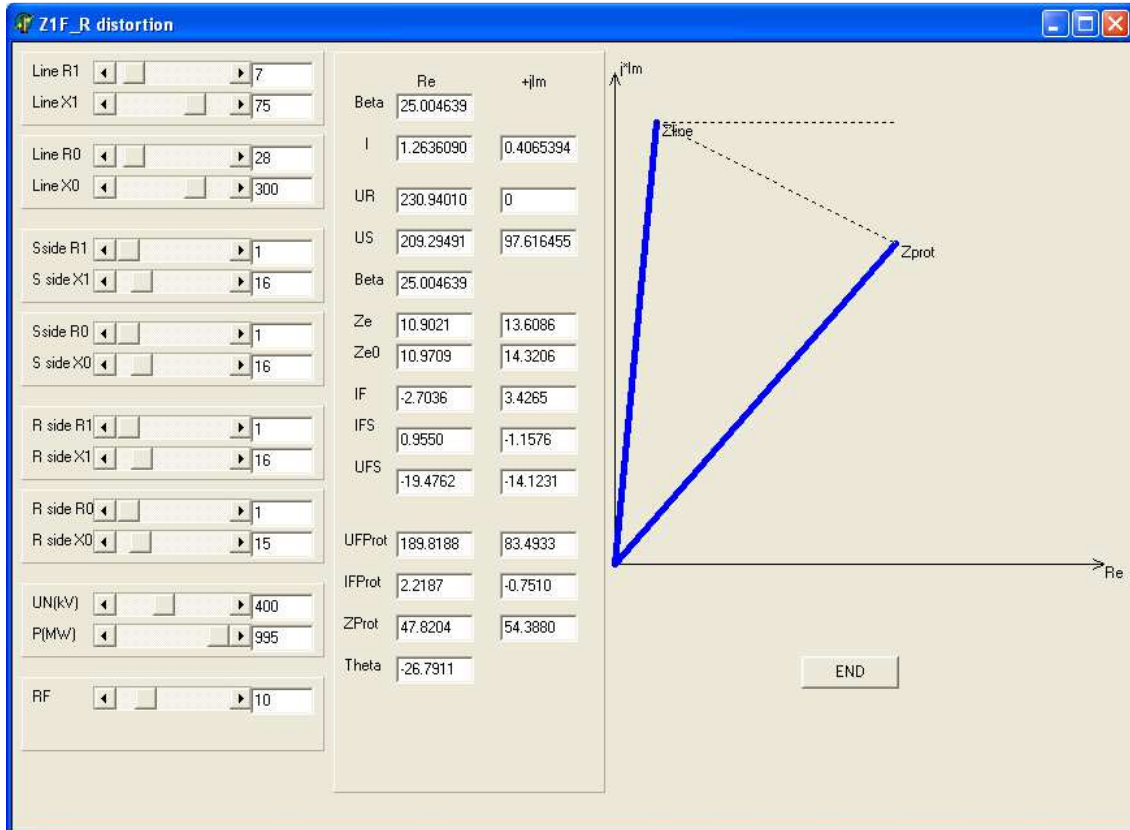


Figure 2-10 Screenshot of the simulation software for phase-to-ground fault

When changing other parameters in the simulation, the calculation seems to be more sensitive. As an example the short-circuit power at the far line end (R side) has considerable influence on the results. See Figure 2-11. These parameters are results of a network reduction; they include the effect of large number of network components and the network configuration.

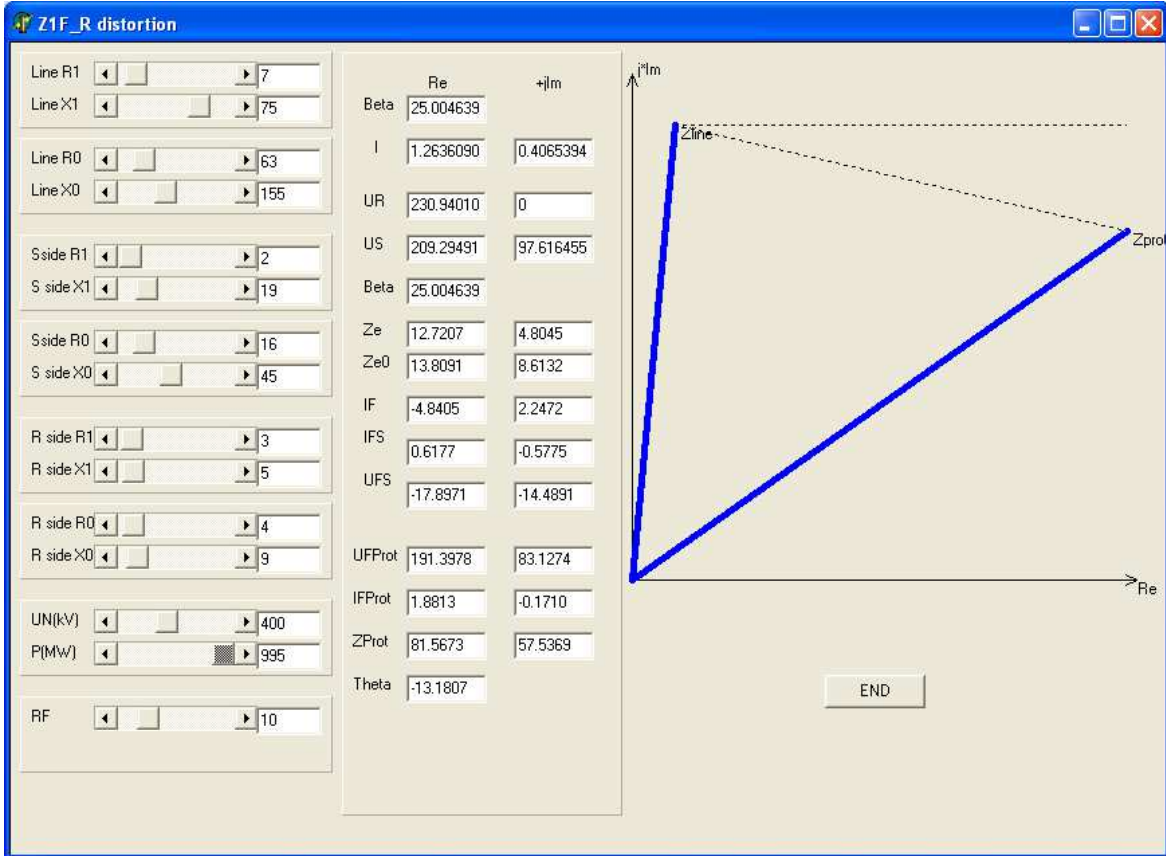


Figure 2-11 Screenshot of the simulation software for phase-to-ground fault

Summary: In a given application, the required tilting of the characteristic can be calculated using the method above. The dynamic tilting of the algorithm applied in the EuroProt devices results less overreaching or underreaching if the pre-fault power transfer is high on the protected line.