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NEW OUT OF STEP BLOCKING ALGORITHM

FOR

DETECTING FAST POWER SWING FREQUENCIES

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Presented to the

30th Annual Western Protective Relay Comfernce
Washington State University
Spokane , Washington
October 21-23, 2003

2nd edition

NEW OUT OF STEP BLOCKING ALGORITHM FOR DETECTING FAST POWER SWING FREQUENCIES

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A sudden change of load in the power system network caused by a fault, by a disconnection of loaded lines or an autoreclose forces the generators to adjust to this new load condition. The adjustment will not happen in a jump step due to the mass of the generators, but rather as an oscillation. Normally it will be a damped oscillation and the generators will be able to return to a normal state condition. In some cases the swing is so large that the generators lose synchronism and run out of step. This power swing and out of step situation causes the current and the voltage of the power system network not to be constant, but rather also to swing in amplitude and phase. An impedance calculation based on these voltages and currents will also oscillate in amplitude and phase with the power swing frequency. The impedance can become so small, that it will enter the fault detection zone or as well the instantaneous zone Z1 of a distance relay and lead to a mis-operation of the distance element. A trip for an out of step situation can be desirable on certain transmission lines to separate the instable grid into sub grids with the goal to reach stability in these sub grids. An additional logic in the protection relay should distinguish between a stable power swing, where the system recovers and an unstable out of step situation and issue only for the out of step situation a trip, if set for out of step tripping.

To prevent a distance relay from having a mis-operation during a power swing, a power swing blocking function is required. The power swing blocking function has the task to detect the power swing cycle and block the distance relay. The classical approach to detect the power swing cycle is to measure the time from when the impedance enters a settable power swing detection zone to entering a smaller second zone (very often the fault detection zone). The impedance trajectory during a power swing cycle will need a certain amount of time to pass this impedance difference. A fault will jump right to the fault impedance and will pass this impedance difference in no time. So the time becomes the criteria to detect a power swing cycle versus a fault condition. If a power swing cycle is detected the distance protection function is blocked. However, a fault during this time has to be detected and cleared by the distance element. For ground and phase to phase faults the appearance of negative or zero sequence current or voltage can be used for releasing the distance protection tripping function, because a power swing is usually a symmetrical phenomenon. To detect a three pole fault during the power swing cycle is more challenging. In this paper one solution is presented where the three pole fault is detected by a ripple on the space vector. When single pole tripping is applied, the power swing blocking and releasing logic cannot use the assumption that a power swing is a symmetrical phenomenon. A more sophisticated logic is required to also handle the situation, where the power swing starts during a single pole open situation.

Finding the proper settings for a power swing blocking function which used blinders or concentric characteristics is not simple and very often requires a power system study which shows the maximum influence of a stable power swing and also the position of the impedance trajectory of an out of step situation. This paper will describe a new algorithm for detecting the out of step and power swing condition. This algorithm, which is based on continuous impedance monitoring, doesn’t require a blinder or concentric characteristics. Therefore no settings are needed. The algorithm continuously monitors the speed and the shape of the impedance trajectory and will immediately see the start of a power swing cycle or an out of step condition. This detection also enables the algorithm to detect fast swing cycles with swing frequencies up to 7Hz.

1. BASICS

To understand the power swing phenomena it is not necessary to simulate a complete grid. On a two machine model with a line between them all the influencing factors can be explained. To simplify our consideration we assume that all elements are without any losses. On the left side in figure 1 we have the generator with the voltage Vs and on the right side we assume a motor load with the voltage Vr. If the mechanical load on the motor is zero then the generator voltage is in phase with the motor voltage and no load current flows over the line. As soon as we increase the mechanical load on the motor a current starts to flow because it is now consuming electrical power. This current will cause a voltage drop over the line and cause a phase angle (ϑ) between the generator voltage and the motor voltage as shown in figure 2. In this situation the mechanical power into the generator, the mechanical power from the motor and the electrical power transported over the line are equal.

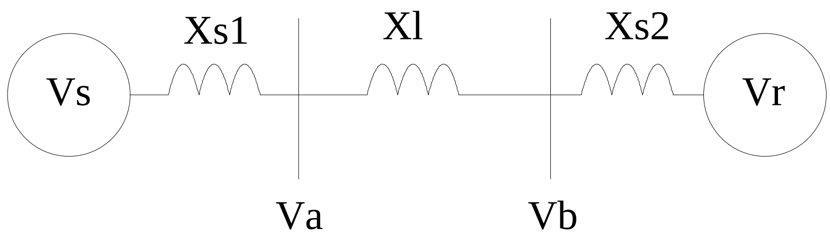

Figure 1: Two machine model

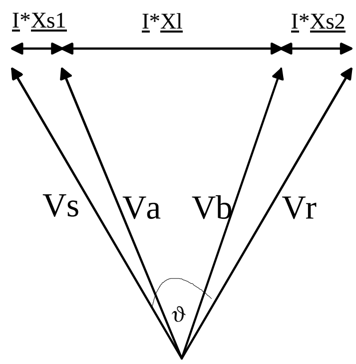

Figure 2: Voltages on the two machine model with load

The relation between the real power over the line and the angle between the generator voltages and the motor voltage can be described as

$$P = P_S = P_R = \frac{V_S \cdot V_R}{X_{S1} + X_l + X_{S2}} \sin(J) \tag{1}$$

The maximum of the real power transport between the generator and the motor is limited by the sum of the source impedance of the generator, the line impedance and the motor impedance. On formula 1 we can see that the maximum power transfer occurs for a voltage angle of 90 degree.

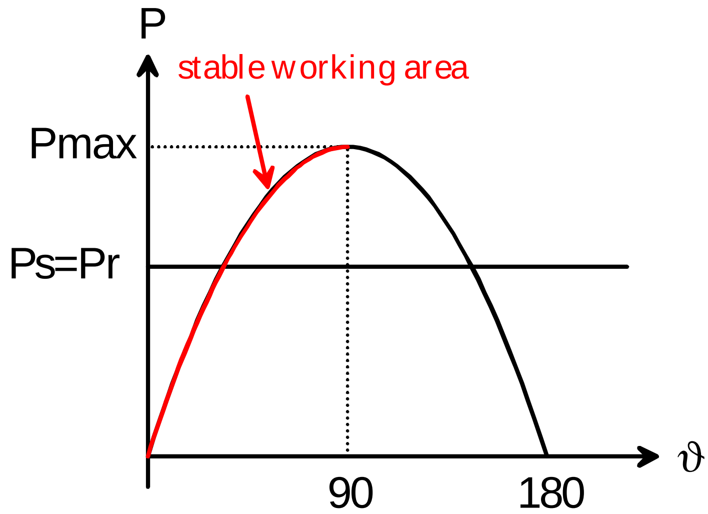

Figure 3 : Real power over the line in relation to voltage angle between the machines

On voltage angles greater than 90 degree the real power becomes smaller and the system becomes unstable because the generator cannot deliver the required real power even with increasing the voltage angle. Normally a grid runs on voltage angles not larger than 60 degree to guarantee stability.

1.1 HOW CAN A FAULT BE DANGEROUS TO STABILITY?

A fault changes the impedance between the machines. A three pole bolted fault, for example will not allow any load transport over the line and therefore the impedance between the machines will be infinite. All the apparent power will go into the fault. In this case the generator will accelerate because the mechanical power driving the generator is smaller than the required electrical power (consumed by the fault). And the motor will slow down because the delivered electrical power is smaller (in this example zero) than the required mechanical power. The voltage angle between these two machines will increase. After the fault is cleared the power transmission could continue to flow via parallel connection to the disconnected line. During each of these steps the impedance between the machine changes and therefore the maximum real power which can be transported. If the mechanical power on the generator is larger compared with the electrical power required over the line, then this difference accelerate the generator and increase the voltage angle. If the mechanical power is smaller, the generator slows down and the voltage angle decreases.

In the following we will discuss this with an example. For this example we will change our two machine model from figure 1 to a two machine model with a parallel line between the machines (figure 4).

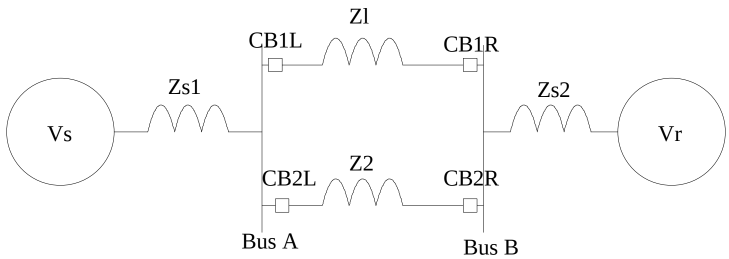

Figure 4 : Two machines with parallel line

We will consider a single phase fault on line Z2, which gets cleared sequentially by three pole tripping on both sides. After a dead time the line successfully recloses.

Position 0 in figure 5 describes the prefault situation when the mechanical power into the generator is equal to the power electrically transmitted over the line and consumed by the motor.

At point 1 the fault occurs. The impedance between the machines increases to a value which will not allow transporting the required power. The mechanical power into the generator is larger than the electrical power going out of the generator. The mechanical power cannot be fast enough adjusted and is assumed as constant during this consideration. The power difference will accelerate the generator and the voltage angle increases. On the motor the opposite happens. Because the mechanical load on the motor (is also considerate as constant) is suddenly larger as the electrical power into the motor, therefore the motor decelerates.

On point 2 the fault gets cleared from one side. The impedance will decrease and allow more power be transported between the machines. Because the mechanical power into the generator is still larger as the electrical power going out of the generator the generator accelerates more.

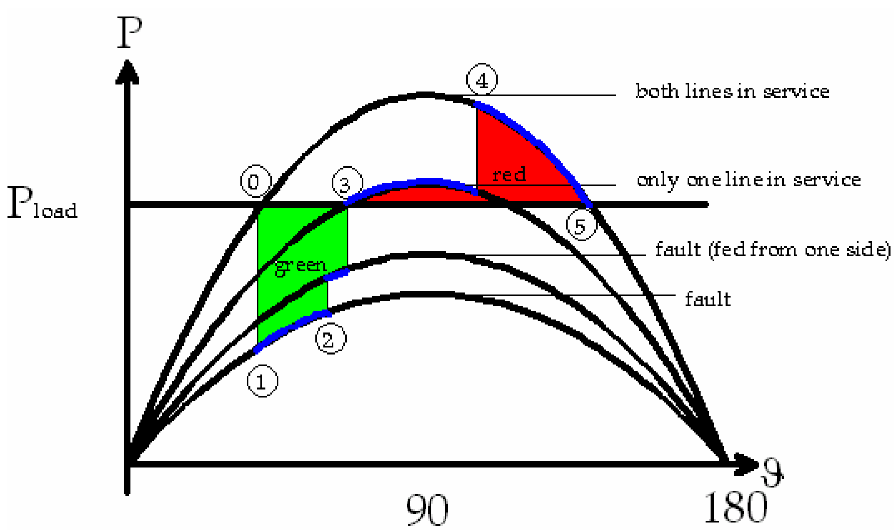

Figure 5: Power unbalance during fault

When the fault is cleared from both sides at point 3, the impedance is small enough to transport the required power over the line. Because of the velocity of the generator it will continue to increase the voltage angle even if the mechanical power into the generator is now smaller than the electrical power going out of the generator. The power difference decelerates the generator and the voltage angle increase becomes slower. The power which accelerated the generator is represented by the green area in figure 5 under the P_{load} line. To decelerate the generator so that the voltage angle increase stops, the same area above the P_{load} line is needed (represented in red)

When the line is successfully reclosed on point 4, the deceleration of the generator becomes stronger because of the larger deficit between the mechanical power going into the generator and the electrical power over the line. The voltage angle increase has to stop before point 5 is reached for the system to remain stable. The red area in figure 5 represent the power which decelerates the generator and this has to be greater or equal to the green area representing the acceleration power to the generator for not crossing point 5.

If the point 5 is crossed the generator gets again accelerated because the mechanical power is greater than the real electrical power. In this case the machines are going out of step and no stability can be archived. If the voltage angle increase stops before point 5 is reached the generator gets decelerated and returned to the stable P_{load} point 0 (after some oscillations around this point).

It is desirable to keep the power which accelerate the generator (green area) as small as possible and the deceleration power (red area) as large as possible to maintain stability in the power grid. The influencing factor for the acceleration power is the fault clearing time. The faster the fault can get cleared, the less time the generator has to accelerate (point 1 to point2/point3). The grid operator has to consider the maximum fault clearing time in relation to the maximum load on the line to avoid instability caused by a fault. The three phase fault is for this consideration the worst case.

To enlarge the deceleration power (red area) the protection engineer can apply single pole tripping for single phase to ground faults, this will allow power transfer over the remaining two phases by decreasing the impedance between the machines. For this application the circuit breaker must be able to trip single pole. A short autoreclose dead time will influence the stability of the grid in a positive way. However, the dead time should be long enough to clear an arc.

1.2 HOW DOES A POWER SWING AFFECT THE DISTANCE RELAY?

During a power swing or the out of step situation, the voltage angle and the load current over the line changes continuously. A distance relay measures the voltage on a certain point in the grid (between the machines) and the load current. Based on these values it calculates an impedance and compares this with settable zone impedances to detect whether there is a fault on the line. The influence of power swing on this measured values and here particularly on the voltage, can be so strong that the calculated impedance becomes so small, that a distance relay may see it as an internal line fault.

The maximum current will flow, when the voltage angle is 180 degree. Then the voltage in the generator and in the motor are in opposite and based on our single line model from figure 1 causes a current

$$I_{\max\_180} = \frac{Vr + Vs}{X_{s1} + X_l + X_{s2}}$$

It should be mentioned that even if the current is at a maximum, the real power over the line is zero because of the 90 degree phase angle between voltage and current.

How much the voltages are influenced by the voltage angle depend on the location of the distance relay. The worst case is, if the relay is in the electrical center between the machines. In this case the voltage would go down to zero. In figure 6a,b,c is the voltage and current vectors shown for different voltage angle, based on the two machine model with one line (figure1). The considered relay is installed on bus A. The electrical center has nothing to do with the geographic center. Electrical center means that the impedance between the relay and the source is equal to the impedance between the relay and the load. In this vector diagram it is assumed that the generator impedance Zs1 is equal to the sum of the line impedance Zl plus the motor impedance Zs2.

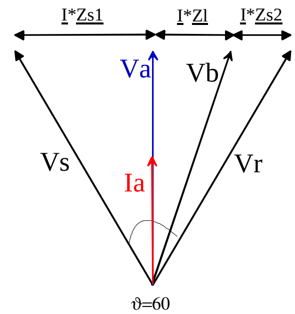

Figure 6a : Current and voltage vectors by 60 degree

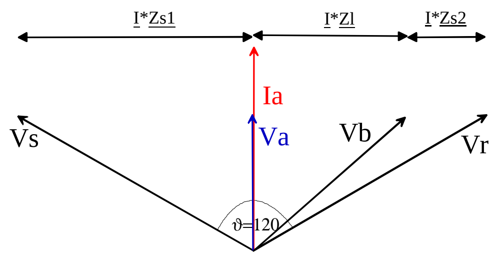

Figure 6b : Current and voltage vectors by 120 degree

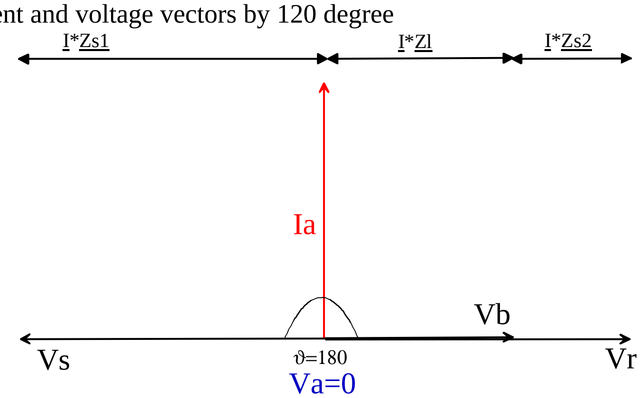

Figure 6c : Current and voltage vectors by 180 degree

If we calculate the impedance seen from relay at bus A on base of the voltage and current vectors from figure 6 and draw each impedance in an impedance plan (R-X-diagram) it becomes visible that all impedances for the different voltage angle are on the R-axis, because the voltage and the currents are in phase. This is only valid for the relay in the electrical center and for a grid that has no losses. When the relay is not in the electrical center, then all impedances are on a line parallel to the R-axis.

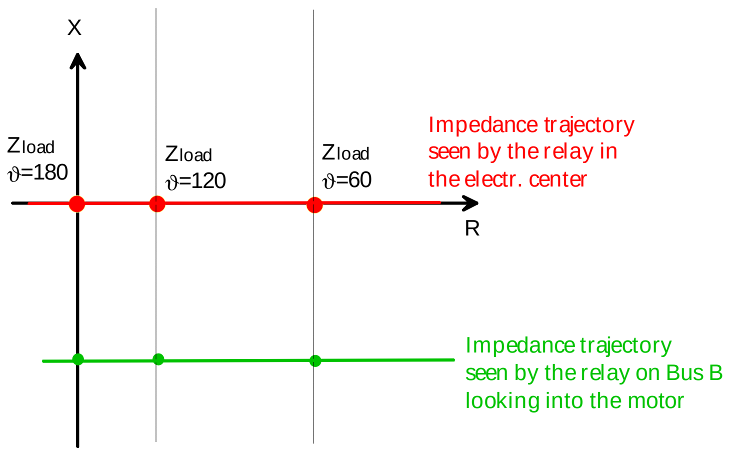

Figure 7 : Impedance trajectory for a lossless system

The impedance trajectory starts somewhere at infinity at a voltage angle of zero and zero load current and moved then towards the X-axis with increasing of the voltage angle. At 180 degree the X-axis becomes crossed. For higher voltage angles the impedance trajectory moved toward the infinity negative resistance.

If we assume now not any more a lossless system and representing the line impedance by Zl ∠φ, then the current Ia in figure 6 will not be any more in phase with the voltage Va rather than has a angle of 90-φ to it. Therefore the impedances calculated based on this vectors are not on the R-axis anymore but on a line with a angle from 90-φ to the R-axis.

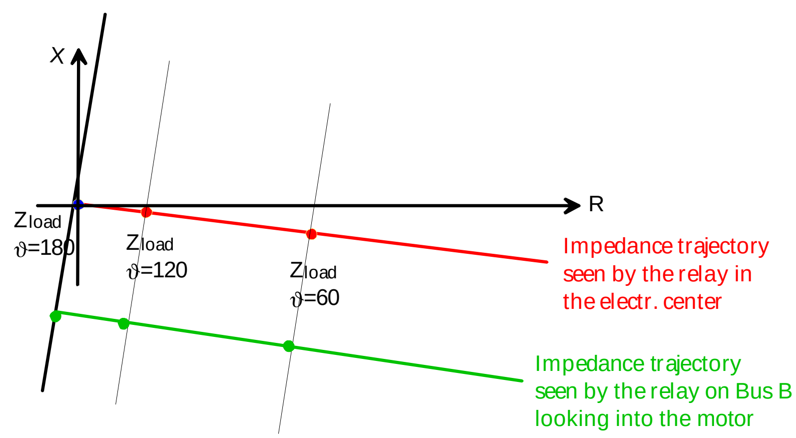

Figure 8 : Impedance trajectory for a system with losses

During all the considerations above we considered that the generator voltage Vs and the motor voltage Vr are equal in amplitude. Only for this situation we will get straight lines as impedance trajectories. More realistic is that the voltages are not exactly equal. In this case the impedance trajectory becomes an additional reactive part. This becomes visible if we consider the case where the voltage angle is zero. With equal amplitudes we had no voltage drop over the line and therefore no load current. With unequal voltages the difference of the voltages is now the voltage drop over the line and we will see a mostly reactive load current.

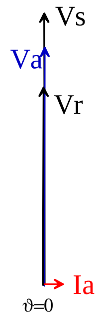

Figure 9: Current and voltage vectors for a system with unequal machine voltages

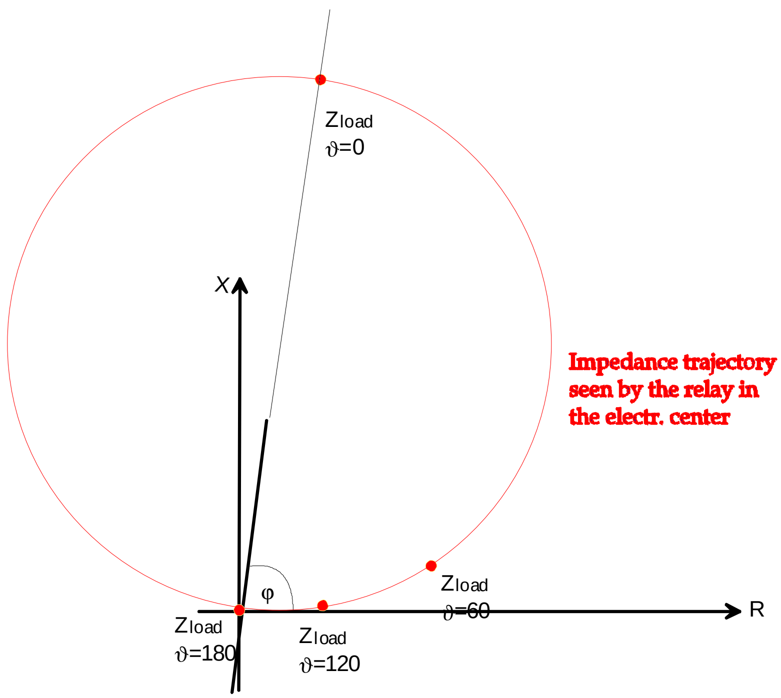

Figure 10: Impedance trajectory for a system with losses and unequal machine voltages

The impedance trajectory is now a circle. In figure 11 is shown curves for different ratios between the machine voltages (E_A/E_B) and with the electrical center through the middle of the line.

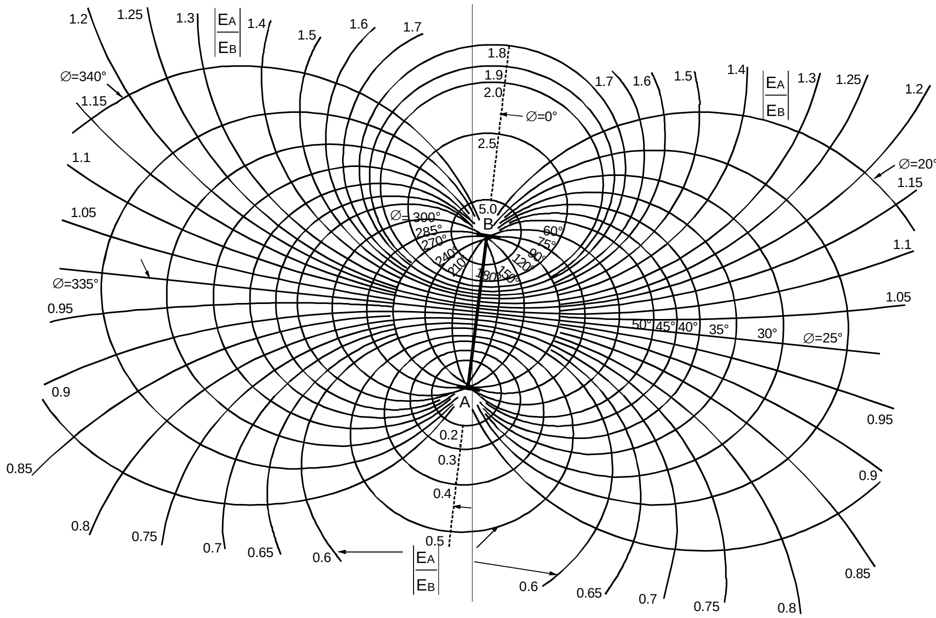

Figure 11 : Impedance trajectories for different voltage ratios between the machines

The considerations above have shown that the impedances during a power swing and particular during an out of step situation (voltage angles > 180 degree) can enter the zone characteristic of a distance relay and miss-operate. Relays close to the electrical center are more likely affected by power swings and need a certain consideration.

2. METHODS OF DETECTING

In distance protection relays, a very common criterion to distinguish whether there is an out of step condition against a fault condition is the speed of the impedance change. When a fault occurs, the measured impedance jumps instantaneously from load impedance to the fault impedance. In the case of an out of step condition the measured impedance will "travel" on a trajectory in the R/X plan with a speed that is much less than that caused by a fault. The speed of the impedance, and we will understand this as impedance change per time, is determined in this case by the inertia of the generators to adapt to a change in the power grid and the slip angle between the generators. Speed is normally a measurement of the time it takes to pass a certain length. Most out of step functions are done using this method. This overview is based on conventional out of step functions, which are based on the measurement of a single relay.

2.1 CONCENTRIC CHARACTERISTIC

The simplest method for this measurement is to determine the elapsed time required by the impedance vector to pass through a zone limited by two impedance characteristics. The second characteristic is concentric around the first one. This can be two additional characteristics which are used specifically for the out of step function or the outer one can be an additional zone that lies concentric to one of the existing distance protection characteristics.

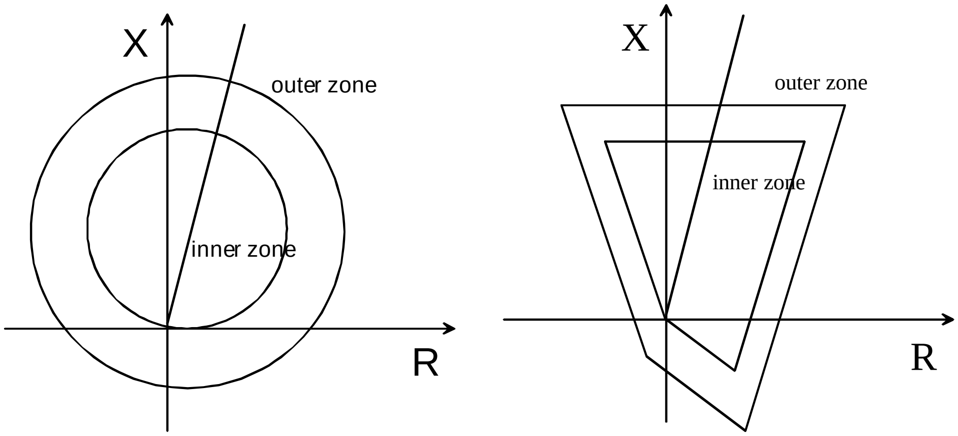

Figure 12 : a) Concentric mho b) Concentric quadrilaterals

The advantage of this concentric characteristic is that the detection of the out of step condition is checked before one of the impedance tripping zones is entered. The setting efforts are limited (in the best case) to a single delta impedance setting and a timer setting. To find the correct settings for these two parameters is normally not so simple and requires a sophisticated grid analysis. A limiting requirement for the application of the concentric characteristic concept is that the R-reach of the outer characteristic cannot reach into the load. This becomes a very limiting requirement especially on long transmission lines. The smallest delta timer setting is approx. 30 ms, so this requires large delta Z settings to detect fast out of step cycles.

2.2 BLINDERS

To overcome some of the disadvantages of the concentric characteristic concept a new method, using independent blinders was developed.

Figure 13 : Out of step detection with blinders

The blinder concept is based on the same principle of measuring a delta time which is needed for an impedance vector to pass a certain delta impedance. The time measurement gets started when the impedance vector crosses the blinder A (outer blinder) and stops when blinder B (inner blinder) is crossed. If the measured time is above the setting for delta time, an out of step situation is detected. If the blinders are set in parallel to the line impedance, then they are optimized for the delta impedance measurement on out of step impedances, because the out of step impedance vectors will normally enter the protection zones in an angle of nearly 90 degree to the line angle. Depending on certain grid conditions, this may not be 100% correct but can be assumed for simplification. The big advantage of the blinders is that they can be used independent of the zone characteristic. The requirement that the load cannot lie inside the delta impedance area can be fulfilled using blinders, even if the zone characteristics are close to the load. To find the correct settings for the blinders are also not so simple and require a sophisticated grid analysis.

Figure 14 : Additional consideration using blinders

An additional consideration is the protection zone that lies behind blinder A. Concerns are slow out of step cycles that will not cross the blinder A. Then if the power swing impedance remains for the set delay time of this zone it leads to an undesired trip.

3 NEW POWER SWING BLOCKING ALGORITHM BASED ON CONTINUOUS IMPEDANCE CALCULATION

One common disadvantage of the methods mentioned above is, that to determine the correct setting for the concentric characteristic or the blinders, a sophisticated grid study is necessary. The settings are fixed and will not adapt to any changed system conditions. If the grid study doesn't consider the worst case, then the appearance of a power swing or out of step condition could lead to a miss operation.

Also the assumption that a power swing is always a symmetrical phenomenon and any asymmetrical current (or voltage) can be used for releasing the distance protection function is in a complex application not fulfilled. In single pole tripping (and reclosing) application the power swing will most likely start during the single pole dead time. A modern power swing block function has to perform also during these conditions.

The follow described method will solve the problems mentioned above. The new method is based on a continuous impedance calculation. The requirements for this new power swing blocking functions are:

- no setting is required a hence no complex setting calculations
- operation of distance protection must be prevented during power swings up to high swing frequencies, up to 7 Hz
- the function should be also maintained during single-pole open condition (auto-reclosure dead time)
- The scheme must trip on all kind of internal faults (also 3-phase) occurring during power swing (immediate release of blocking)
- minimum incremental setting of 1ohm is required thus allowing for high fault resistor coverage also on heavy loaded long lines

All this requirements cannot be met by one single measurement approach. Thus the patented swing detection consists of two modules, working in parallel. The first module uses a concentric characteristic. A setting is not necessary, because the outer characteristic has a small constant distance (1 Ohm based on 5A) to the fault detection area. This module is only needed to detect very slow swing impedance movements during a power swing (< 5 Ohm/s) because the second module is optimized to detect very fast impedance movements and has a lower limit of 10 Hz/s. Upon entering the power swing polygon a timer set at 30ms will be started. A power swing is detected, if the timer elapses before the fault detection zone is reached

The second module is the crux of the new power swing blocking function and is based on a continuous impedance calculation of three modified loop impedances. The power swing detection monitors the load impedance vectors continuously. During a power swing condition these vectors are describing an elliptical path. By analysing this ellipse, it is possible to determine if the swing is stable or unstable (out of step condition). Furthermore, it is possible to determine at any point in time during the power swing if a fault has occurred.

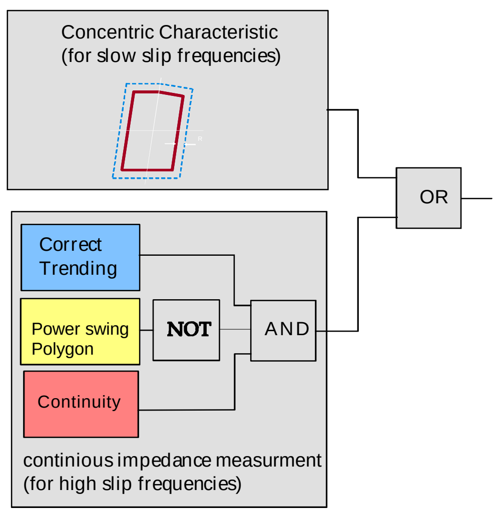

Figure 15 : Components of the new power swing detection function

Continuous measurement of the load impedance means that every 5 ms an impedance calculation for three loops is done and checked for continuity and monotony.

Correct trending checks that the resistance is changing at least by 50 mOhm during each calculation**.**

If this criterion is fulfilled for six following calculations a power swing suspicion is established. Correct trending is only checked as long as the impedance has not reached the power swing characteristic, because inside the power swing characteristic an impedance change is not necessary. During a stable power swing the impedance trajectory will have a reverse in the resistive-direction and may not fulfill the correct trending requirement.

The test of **continuity** checked that the delta in R and in X is not above a certain limit,

thus it guaranties that the impedance locus has a uniform movement with no abrupt changes.

The limit gets calculated in relation to the previous deltas. This leads to a dynamic calculation of the limit and an automatic adaptation to the change of the power swing trajectory speed. A delta time setting is not required anymore because it is determined by the calculation cycles of the algorithm.

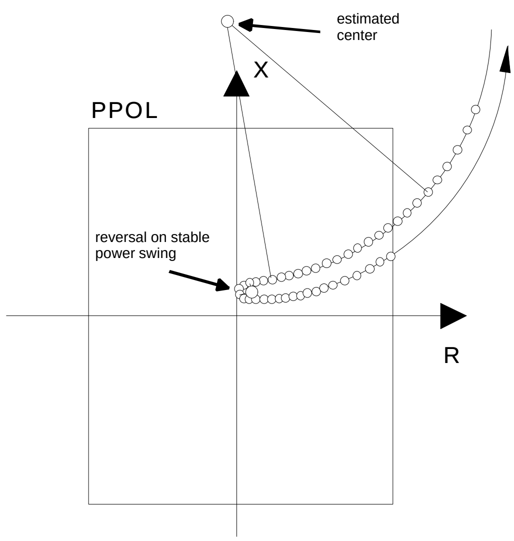

Figure 16 : Check of correct trending

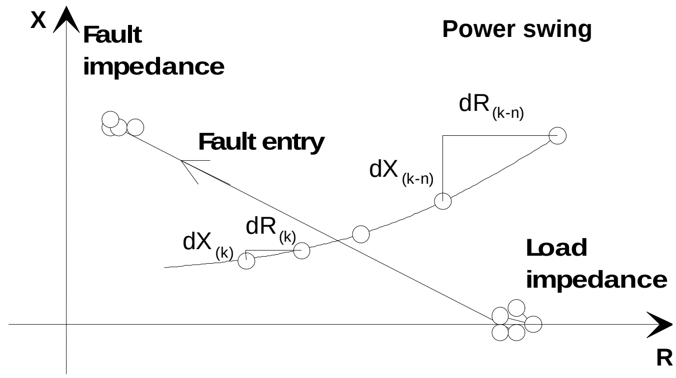

Figure 17 : Check of continuity

The dynamic adoption on the power swing trajectory speed enables the function to detect also high slip frequencies up to 7 Hz. Only if continuity and monotony are fulfilled, a power swing is detected even before the power swing polygon is reached. A starting power swing cycle is detected not later as 30 ms (6 * 5ms) after it starts. With reaching the power swing polygon the distance protection function becomes blocked. If continuity is not fulfilled for following six calculations a fault is assumed and the distance protection function becomes activated.

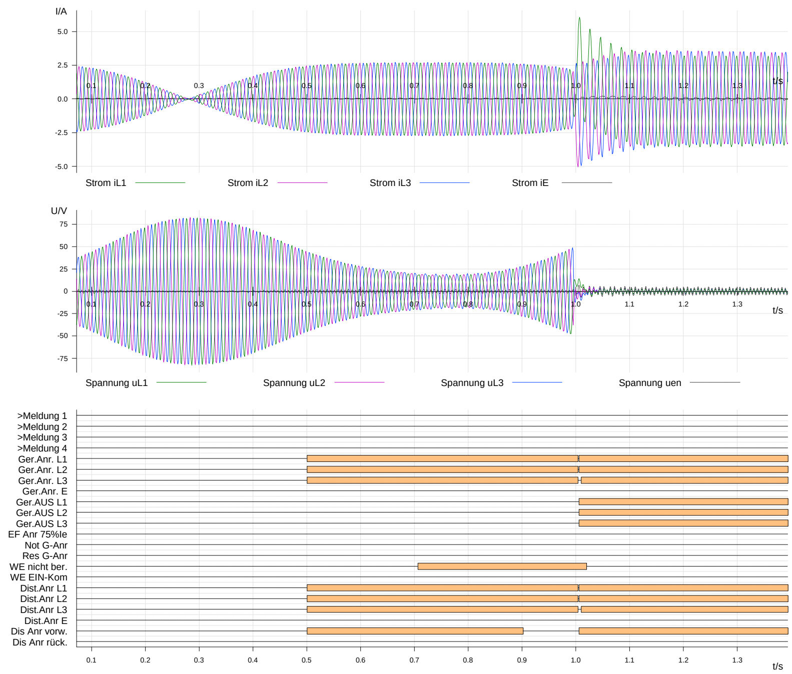

Figure 18 : Secure detection of internal three pole fault during power swing blocking

3.1 SINGLE POLE OPEN CONDITION

During the single pole open condition the power swing detection must be modified to take note of the fact that it is possible for load to be transferred via the zero sequence system of the line. This also applies when parallel or adjacent lines are in the single pole open condition.

Several logic and measuring tasks are required to achieve power swing detection. For one, it is necessary to distinguish between a symmetrical condition (load, three phase fault and power swing) and a non-symmetrical condition due to an unbalanced fault. This is achieved by symmetrical component evaluation. The symmetry condition is a prerequisite for release of the power swing detection condition. During single pole open conditions this must be changed, therefore the symmetry detection task is replaced by the single pole dead time task when single pole open is detected.

The single pole dead time task distinguishes the condition power swing and two phase to ground faults from other system faults during the single pole dead time. The distance protection task already contains a special ground fault recognition function which operates during the single pole dead time (distribution of sequence component currents). This detection of a ground fault by the distance protection during the single pole open condition is therefore also used to directly remove the power swing blocking condition.

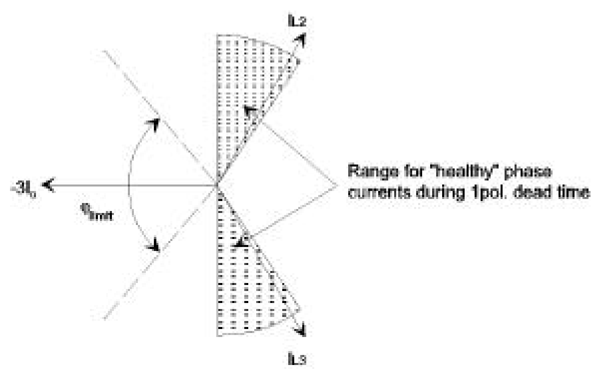

Figure 19 : Power swing detection during on pole open situation

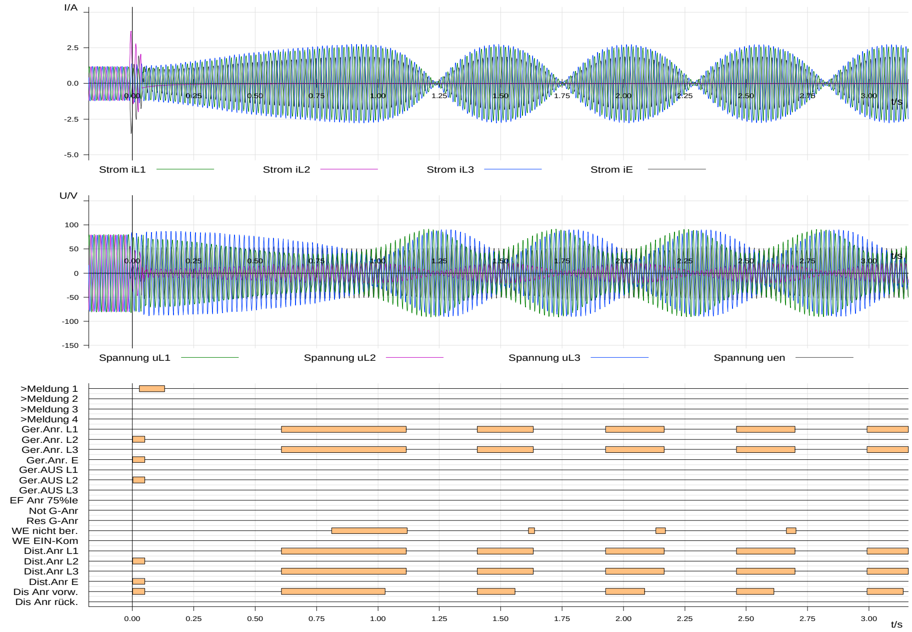

Figure 20 : Secure power swing detection during on pole open situation

3.2 DIRECTION DETERMINATION DURING POWER SWINGS.

During the power swing condition the polarisation of the distance measurement with memory voltage is not possible. The voltage phase angle jump (approximately equal to the load angle) after fault inception is not predictable and may assume any value from 0 to 360 degrees. The un-faulted voltage (cross polarisation) is also not valid for the direction measurement during a power swing. The measured voltage phase angle is predominantly dependant on the relay location relative to the “electrical centre” of the power system subjected to the swing condition.

The actual faulted loop voltage returns a true direction decision. During close in forward faults and reverse busbar faults this voltage is zero or approximately zero which again renders it useless for a direction decision. In this case, a special negative sequence direction measurement is done. The actual measured phase currents and phase to ground voltages are used to compute the negative sequence current I_2 and the negative sequence voltage V_2. From this the negative sequence impedance is calculated:

$$\underline{Z}_2 = \underline{V}_2 / \underline{I}_2$$

The negative sequence impedance is not affected by the power swing so that it indicates the relative position of the fault. During a reverse busbar fault the negative sequence impedance of the line and opposite infeed is seen while the own source negative sequence impedance is seen during forward faults. Fig 13 shows an example of a close in, single-phase fault during a power swing (with CVT transient) that was cleared with correct direction measurement. In this case a reverse busbar fault and therefore no trip by the distance protection. The fault current is seen to be less than the current due to the power swing although this was a close in fault.

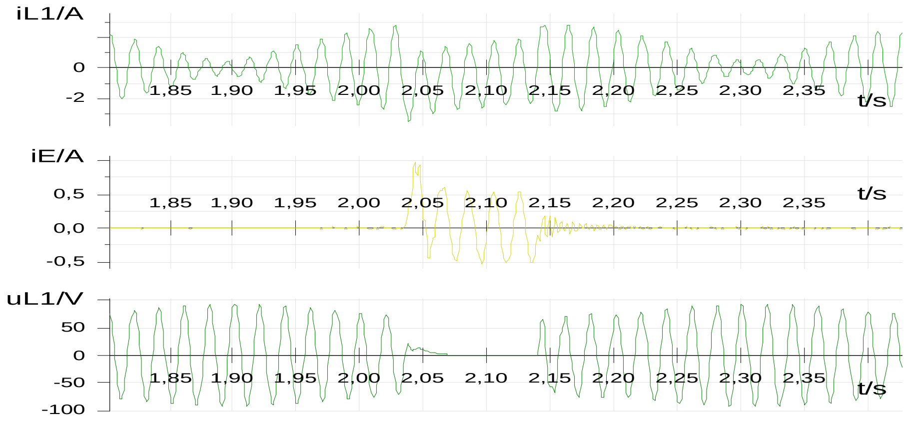

Figure 21 : Example of fault during power swing

With the negative sequence direction check, it is not possible to determine the direction of each measured loop separately. For this reason, the negative sequence direction check is only used during the special case where there is a power swing and the voltage of the faulted loop is too small for a direction determination.

4. CONCLUSION

This paper presented the basics for understanding of the power swing phenomena and the problems associated with the distance protection principle. After the conventional power swing and out of step blocking functions are presented, the paper introduced a new approach for power swing blocking function with the following advantages:

- No need for setting parameters, thus, avoiding the need for complex setting calculations
- Prevents mis-operation of distance protection during power swing up to high slip frequencies from 7 Hz
- Maintains function during single-pole open conditions (auto-reclosure dead time)
- Trips on all kind of internal faults (also 3-phase) occurring during power swing (immediate release of blocking)
- minimum incremental setting of 1ohm is required thus allowing for high fault resistor coverage also on heavy load long lines

5. LITERATURE

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