PROTECTION SCHEME BASED ON NON COMMUNICATING RELAYS DEPLOYED ON MV DISTRIBUTION GRID

Cristian JECU
OPEN - Schneider Electric – France
cristian.jecu@open-groupe.com

Philippe ALIBERT
Schneider Electric – France
philippe.alibert@schneider-electric.com

Bertrand RAISON
UJF - France
bertrand.raison@g2elab.grenoble-inp.fr

Raphaël CAIRE
Grenoble-INP – France
raphael.caire@g2elab.grenoble-inp.fr

Olivier CHILARD
EDF – France
olivier.chilard@edf.fr

Sébastien GRENARD
EDF - France
sebastien.grenard@edf.fr

ABSTRACT

This work is related to protection systems on MV distribution networks. Most of these grids are currently protected by a single relay on the beginning of each feeder. The Smart Grids necessity is becoming more and more a reality for the grids of tomorrow. These more complex grids with Distributed Generation (DG) interconnection could require a more complex protection system to achieve high quality service and enhance the grid stability. This work proposes non communicating, distributed distance relays. These deployed relays would divide the feeder in smaller protected areas leading to shorter outage occurrence and duration for loads and producers. The proposed method was tested on all types of grids with overhead lines, cables and mixed, for all several different neutral groundings of the HV/MV transformer with or without DG presence. This method is subject to a patent deposition in 2012.

INTRODUCTION

The purpose of this work is to propose a methodology to coordinate, set and optimize the selectivity of the distributed protective relays into the distribution grid. This protection scheme is based on non communicating relays that use a transmission impedance evaluation based technology adapted for the distribution grids. The distribution grid has some particular problems such as the heterogeneity of feeders. This is due to the different types of conductors (with different linear impedances) that are used in this type of grid. The adapted distance relays are deployed in the grid in order to divide the consumers and producers into small zones. The proposed relay algorithms do not rely on any communication system in order to detect a fault and to trip. The only communication that might be added is low speed communication that could allow the relays to adapt the settings for an optimized protection of different feeder configurations. Therefore the relays are independent one from another.

The presence of DG in a non-dedicated feeder of the distribution networks could cause the following problems [1],[2],[3]: short circuit current modifications, undesired relay tripping on the healthy feeders, relay blindness, tripping errors of the DG relays, unexpected islanding.

Many DGs are connected to the grid through power electronics devices that limit the short circuit current. But if they are connected without power electronics converters, they can inject large short circuit currents [4]. Other methods to limit DGs contribution is to limit their sizes when connected to a non-dedicated feeder [5]. This work presents an amelioration of the previously proposed methods, which were computing the imaginary part of the impendence (conductors actual value), as explained in [6]. The method works for earth faults. This paper shows only the single phase results.

THE DISTRIBUTION GRID

Many distribution grids are mainly operated radially and have several feeders that are energized from the bus bar of the substation. A single protective relay is mounted at the beginning of the feeder and protects it. The conductor segmentation of the feeder is very different from the one on the transmission lines due to the different characteristics of the grids structure and its evolution.

The tested grid is divided in several zones due to the deployment of the relays. The relay locations in the feeder and the grid division are presented in Fig 1.

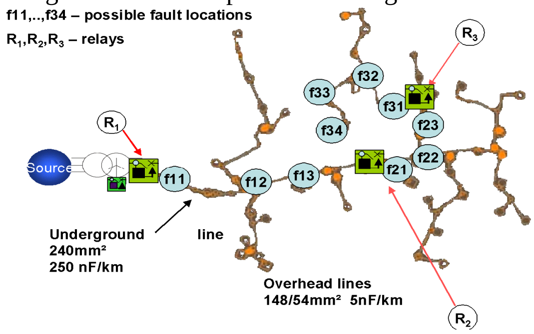

Fig 1. The geographical distribution of a the tested feeder – relay deployment

The relays are equally distributed by the impedance of the protected conductors. Several tested fault locations are also presented in Fig 1: f11, f12, f13 are between R_1 and R_2; f21, f23, f23 are between R_2 and R_3 and f31 to f34 are downwards of the relay R_3.

PROPOSED LOGIC OF THE RELAY

Basic relay principles

The method is based on two steps: the detection and the discrimination. Each of these distinctive steps uses its own measure instead of both using only one all-purpose measure. This is because none of the considered measures (voltage, current, all their combinations and all of their forms – phase, symmetrical components, different transformations – Park, Concordia, Fourier) showed the potential that the two combined measures can assure, [6]. The detection step is already available (ANSI code 67/67N, [7]). The actual relays are able to detect the fault presence even with high impedant faults [8]. For this detection step, the overcurrent based relay was proposed. The relay should be directional for the purpose of making the difference between the short-circuit current injected from a DG or from the main source of the feeder [9]. The legislation that is currently used in Europe does not allow islanding only with DGs as sources. Therefore in all the studies, if the relay detects a fault in its upward position (a DG in its downward position is generating the detected upstream current), it does not continue with the discrimination step, hence it does not trip.
The time discrimination step is necessary for distributed relays that do not rely on communications in order to determine the tripping delay (time delay). Indeed, a tripping delay of Δt is needed while assuring time based selectivity. Due to the usual value of this tripping delay (0.3 s), the limitation imposed by the load relays (0.2 s) and the bus bar relay (around 1 s) a distributed relay can have only three different tripping times (t0, t0+Δt and t0+2·Δt). Therefore a maximum of three different zones can be defined for each of the deployed relay (e.g. the relay R1 that has 2 thresholds separating its three zones defined by the two downward relays, Fig 1.). The proposed logic may be possible using microprocessor based relays [10]. The overcurrent relay solutions, [11], could not be applied due to the complexity of the discrimination step, especially on the grids with compensating coil grounding of the transformer [6].
In order to perform the best discrimination of the faulted area, the index/measure that is used by the relay must have a great sensitivity to the fault location variation and to be the less sensitive as possible to the variation of the fault resistance. These conditions are needed for the discrimination accuracy of the faulted zone. The precision is needed in order to assure the selectivity and to avoid double tripping. E.g. a relay should not discriminate a fault in a closer area than the real one.
The impedance index was proposed, for its high performances regarding the criteria previously mentioned. Therefore the distance relay formula presented in equation (1) was used, according to [12] and [13].

$$Z^1 = \frac{V_A}{I_A + I_R \cdot k_0} \quad \text{where} \quad k_0 = \frac{Z^0 - Z^1}{3 \cdot Z^1} \qquad (1)$$

As mention before, the major problem is the heterogeneity of the distribution grid. Indeed, correction factor k_0 is thus different for every type of conductors. That problem can be solved by an optimization of the formula. The k_0 coefficient is chosen as a complex number that is optimized. The optimization part is explained later in this paper, but first the logic of the relay is presented.

The relay logic

When the relay detects a fault and starts the discrimination step using the parameters found in the optimization process, it determines a value of a virtual impedance based on the coefficient k_0. This value will be compared to the first thresholds in the complex domain (Fig 3.) in order to decide whether the fault occurred in the first, second or third zone (there are 3 zones available for R1). The comparison of the determined value with the threshold is done mathematically simply finding on which side of the threshold it is found. After the zone determination, the tripping delays are computed accordingly to this determination (and of course the number of downwards relays). Fig 2. presents this logic.

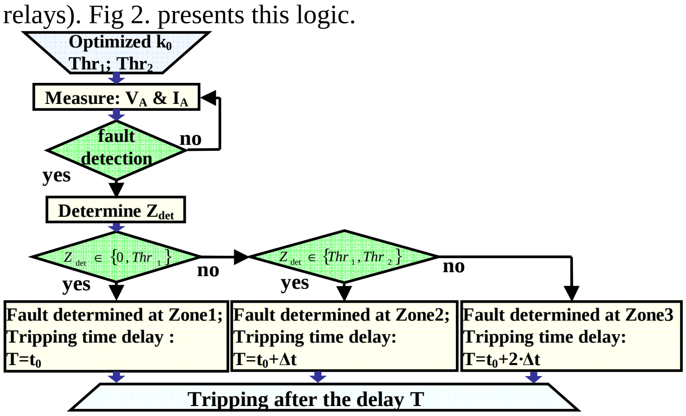

Fig 2. The relay logic

The relay will trip after a specific delay only if the detection step is still alerting the presence of the fault. Otherwise the relays that are used as back-up will cut safely the downstream part of the network (e.g. R_1 and R_2 for a fault that occurred at the end of the line and the R_3 tripped in t_0).
The settings values needed in this logic, k_0 (for the impedance computation) and the thresholds (Thr_1 and Thr_2) are previously optimized for a given grid configuration.

METHOD DESCRIPTION - FINDING THE SETTINGS FOR A GIVEN RELAY

The proposed method consists of an optimization process done in order to find the setting and the functioning of the deployed relay, assuring its selectivity with the other relays of the protection system.
The relay will use a set of settings for every grid configuration. Each relay will have its own set because it will compute different measures and will take different decisions. Finding the settings consists in finding an optimized complex coefficient k_0 and a set of maximum two thresholds (due to the maximum of three zones), that are

able to discriminate the most cases of fault locations with the wider range of fault resistance. The method needs some information of the grid structure (such as the length and the independences of the conductors as well as all of the feeder construction geometry, for conductors and if there are DGs).

The coefficient research

The research is done within a predefined domain for the k_0 coefficient in the complex space. The domain and the step size are input values that will impact the results quality while following the proposed methodology. The bigger is the domain chosen the greater are the chances that the best coefficient will be found within the domain. The step size of the domain sets the accuracy of finding the coefficient (its precision). This coefficient has lost the physical (distance) representation that it had in the original formula (1). In this representation, it is just a complex number chosen mathematically.

Choosing the thresholds – without DG presence

The coefficient is tested using as thresholds the lines created by two values, obtained with the given coefficient, of the faults that are both located at the boundary of the protected zone but have different resistances. Fig 3. shows some theoretical values obtained for the determined impedance.

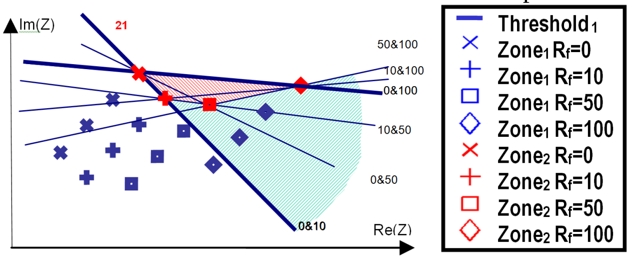

Fig 3. Threshold choice using determined values

This figure was just created for the purpose of understanding the threshold choice. The red values are obtained for faults (of 0, 10, 50 and 100 Ω) that occurred at the boundary of the zone. The choice is done using these values. The resistance values are chosen accordingly to the probability of occurrence (0 to 100 Ω represents 94 % of the fault). Least resistant faults have a greater probability of occurrence. The blue values are determined for the same set of values of fault resistances but for all the fault positions that are between R_1 and R_2 (so for f11, f12 and f13). There are several solutions for each couple of these 4 values (due to the choice of 4 values of fault resistance). A total of 6 lines may be chosen but not all of them are respecting the wanted criteria of never discriminating a fault in a closer zone than the real one. We use only the lines that separate all the red values in one side of the line. Two examples are presented in Fig.3.: a line made for the 0 and 10 Ω that will be used for this case and a line made from 0 and 100 Ω that does not respect the criteria, so it is not used.

The logic of the optimization

After finding, for each coefficient, the best set of threshold, the decision between several coefficients with several possible thresholds is done on the base of probability of success. Naturally, we keep the set of parameters that discriminates most of the faults (with various locations and various fault resistances). The logic followed in this optimization is presented in the Fig. 4.

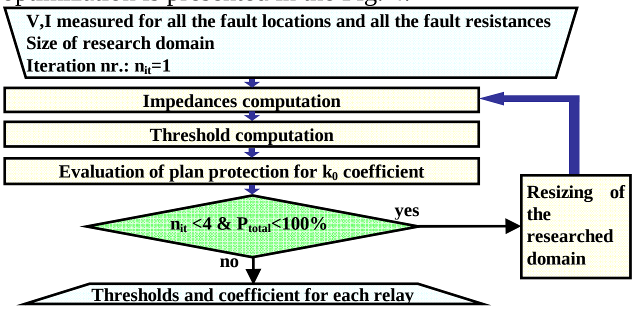

Fig 4. Optimization logic on k_0 coefficient

The voltage and current values measured for all the fault locations and all the fault resistances are obtained by using dedicated simulation software for electrical grids. After obtaining the percentage of success of the discrimination step, if the percentage 100% is not obtained or the number of iterations is inferior to a pre-established value, there is another iteration of the same process of parameters research. The new domain is build symmetrically around the best coefficient found at the previous iteration in order to find an even more accurate coefficient and therefore to obtain a better percentage.

The DG impact - settings

The DG presence obviously will decrease the percentage of success. The most important DG perturbation is due to its size. We imposed that the situation of discriminating the fault in a closer zone should never happen due to the double tripping that might occur. We can avoid this, at the moment of coefficient selection criteria, by keeping only the coefficients that always translate the DG contribution in discriminating the fault in a further zone.

RESULTS

The obtained values may have unexpected characteristics as negative real and/or imaginary parts or an unexpected variation due to the variation of the fault location or the fault resistance, Fig. 5.

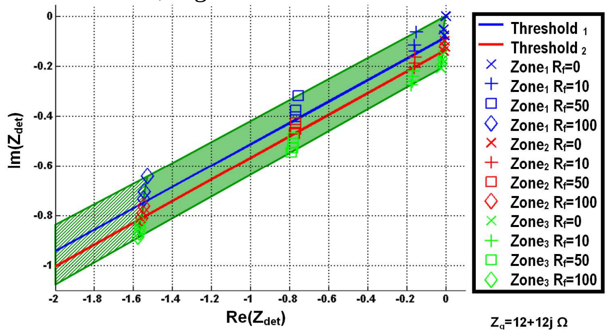

Fig 5. Results obtained for R_1 on a rural feeder

As explained earlier, they should be treated as mathematical values and only be compared to the thresholds from the point of view that they were constructed and not from a physical representation or any expectation formed, based on experiences with other distance relays. The results are very promising reaching 100% of success of discrimination for the most of cases that do not have DG injection. Resuming the results in percentage obtained for different grids with different neutral groundings, using a "π" and a complex representation of the conductors, out of 46 case only 9 did not provided solutions with 100 % correct discriminations. Fig. 6. presents the percentages of success obtained without DG presence. By success we represent the probability that the method will function perfectly (for all possible situations). It must be understood that, the way the method is conceived, there are not any cases that allow a wrong tripping. The difference from the obtained percentage and the 100% value represents delayed tripping situations (under the maximum clearing time, always performed by the closest relay, which isolates the smallest possible zone).

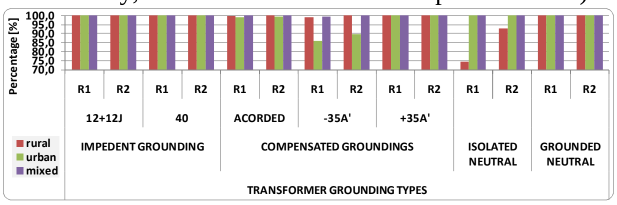

Fig.6. Success probability of the method

For a DG presence the success values are reduced accordingly to the size of the DG (injected current). As previously explained the measured values are perturbed by the unknown DG contribution. In our simulations, for the different situations, the DG reduced the percentages with different values: the minimum was of 2%; but the maximum might be very high as we cannot guarantee a maximum error value. In conclusion, the DG contribution, to the errors that they introduce, must be controlled in order to avoid double tripping.

CONCLUSIONS

This work is concentrated on a proposed method of optimization that allows several relays to be deployed alongside the grid. Each relay must have their own separate set of settings (coefficient and thresholds) for every configuration of the feeder. The change between particular sets according to the feeder configuration could be done using some low debit, uncritical communications. This exchange is very basic. It only needs to communicate the number of the set of settings correspondent to the new configuration and receive in return the confirmation of the set changing to the new one. This communication is not needed while the fault occurred so it does not affect the performance of the protecting system during a fault.

The obtained results show that for the most of the cases without DG injection, the method is able to find a perfect or nearly perfect solution of correct discrimination. The DG presence is a perturbation and if the errors introduced are not controlled, the risk of double tripping appears. The method may apply to grids that don't change their configuration frequently and that has a small number of configurations (limiting the number of settings, unlike the grids with compensated grounding that are limited in the tuning precision – these grids have a lot of configurations).

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