# Protection Issues in Microgrids with Multiple Distributed Generation Units


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*Abstract* -- **The application of local generators in distribution grids has consequences for the protection system. In this paper, protection issues concerning distributed generation are discussed, followed by a discussion of the results of simulations. These simulations concern the effect of local induction generators on protection selectivity in a system with parallel distribution feeders and the effect on fault detection.**

**It is found that local induction generator can pose a selectivity problem in a system with parallel feeders when a line-to-line fault or a double line-to-ground fault occurs. Regarding the fault current detected at the beginning of a feeder, detected current is lowest when a line-to-line fault or a line-to-ground fault occurs. Depending on the relay settings, this can result in a detection problem.**



***Index Terms*--Distributed generation, power system protection, selectivity, induction generator, power system simulation, short-circuit current.**


## I. Introduction

Introducing generators in radial distribution grids may cause protection problems [1]-[11]. The need for an adaptation of the protection scheme when a significant amount of generation capacity is installed locally is an impediment to the use of distributed generation (DG). Case studies concerning these problems are discussed in, [1], [2], [5]-[7] and [10].

In the first section of this paper aspects of the protection of distribution grids with local generators are discussed. In the subsequent sections simulations of systems with distributed generation are discussed. With these simulations the influence of local generators on protection selectivity and fault detection is investigated. In order to limit the scope of the discussion, the generator used here is limited to one type: the induction generator, which is used often in practice, e.g. in CHP units.

## II. Protection Issues

Connecting generators to a distribution grid or microgrid, which is understood in this paper as an islanded grid, changes its properties significantly. Voltage profiles and dynamic behavior are altered. The short-circuit power increases and current paths become more complicated. On the other hand, in case of microgrid operation, the short-circuit power may drop dramatically through the disconnection from a rather stiff grid. As a consequence, classical protection techniques may become inadequate. Problems concern loss of selectivity, overcurrent protection level, earth-leakage protection, disconnection of generators, islanding and single-phase connections.

The power output of distributed generators is often unpredictable. Because of this, the behavior of a grid when a fault occurs, changes constantly. Interaction with neighboring grid sections causes problems as well. Three types of generators have to be considered: synchronous and induction generators and inverter-interfaced production units, all with very different properties.

Because of this, protection has to depend on the state of the local grid (e.g. instantaneous production and consumption levels). Protection parameters have to be updated frequently. Protection of local grids during intentional islanding (microgrid operation) has to be investigated as well.

### A. Selectivity

System protection is selective if only the protection device closest to the fault is triggered to remove or isolate the fault. If this takes too long, the protection at a higher level takes over. This restricts interruptions to only those components that are faulty [12], [13]. Without distributed generators, power flows in one direction, during normal operation as well as when faults occur. This allows for the creation of a selective system by applying time grading to overcurrent relays.

When DG is installed, this system is inadequate. A possible scenario is the disconnection of a healthy feeder by its own protective relay because it contributes to the short-circuit current flowing through a fault in a neighboring feeder. On the other hand, if a fault occurs on the connection between the supplying grid and a local network, disconnection of feeders (or its generators) should take place [1], [2].

The tripping current of protective devices has to be situated between the maximum load current and the minimal fault current. Both depend on the state of the grid, including the state of the generators, and the fact whether it is islanded or not. Since the power output of distributed generators is not constant and possibly irregular, parameters of protection devices should, in theory, be updated constantly [14].

### B. Overcurrent Protection and Earth-Fault Protection

The presence of generators reduces the fault current or


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overcurrent detected at the beginning of a feeder or the fault current supplied by other local generators. Because of the generator's contribution to the short-circuit current, the voltage drop over the feeder section between the generator and the fault increases, which results in a lower fault current from the grid. If this reduction is sufficiently large, currents detected at various points are too low to trigger fast disconnection [1], [11]. This can result in prolonged overcurrents or earth faults.

### *C. Protective Disconnection of Generators*

Generators have to be protected against internal and external short-circuits, over- and undervoltages, unbalanced currents, abnormal frequencies, harmonic distortions and excessive torques [3]. The grid itself and persons have to be protected as well [15]. Depending on the location of the fault, the protection mechanism of a generator should use a different time delay, ensuring selectivity. If there are one or more protection devices between a generator and a fault, these devices should be given the opportunity to disconnect the fault. If the fault is close to the generator, fast disconnection of this generator is required. If generators can be disconnected quickly, classical selectivity can be restored [2], [4].

### *D. Islanding – Microgrid Operation*

According to many grid codes, disconnection of generators is required to prevent unintentional islanding. The main concern is safety of persons [15]. However, microgrid operation through intentional islanding for short or long periods has to be considered as an alternative option. It would drastically increase the reliability of local grids because power delivery would be independent of the state of the supplying grid. However, the behavior of such a microgrid when a fault occurs, is completely different because of the changes in short-circuit power from the main grid, requiring adapted protective measures.

### *E. Single-Phase Connection*

Certain generation units inject single-phase power into the distribution grid, e.g. small photovoltaic systems or Stirling engines [16]. This affects the balance of the three-phase current, resulting in increased current in the neutral conductor and stray currents in the earth. This current should be limited to prevent overloading and to assure the safety of persons [17].

## III. SELECTIVITY WITH PARALLEL FEEDERS

In order to better understand of the selectivity problem described in the previous section, fault situations in a simple distribution network are simulated. The generators used are induction machines. The layout and data of this network are given in Fig. 1. The grid consists of two identical, parallel feeders, *X* and *Y*, connected to a busbar. This three-phase system is operated at 400 V. The busbar is connected to an external grid (10 kV) by means of a cable and a transformer.

Five cells are connected to each feeder. Each cell consists of a load, four induction generators and four capacitors. The capacitors are added to supply reactive power to the generators. In each cell, a capacitor is switched on for each active generator. All loads, all generators and all capacitors are identical.

Simulations are conducted with switch *A* closed and switches *B* and *C* open, resulting in a parallel connection of the feeders.

Simulations are carried out for four cases: 1, 2, 3 or 4 active generators per cell. When two generators per cell are in operation, all active power consumed within the network is generated internally. When four generators per cell are in operation, an amount of power equal to local consumption is injected into the supplying grid. Four short-circuit types are simulated: three-phase fault, line-to-line fault, double line-to-ground fault and single line-to-ground fault [12]. Fault impedances are zero.

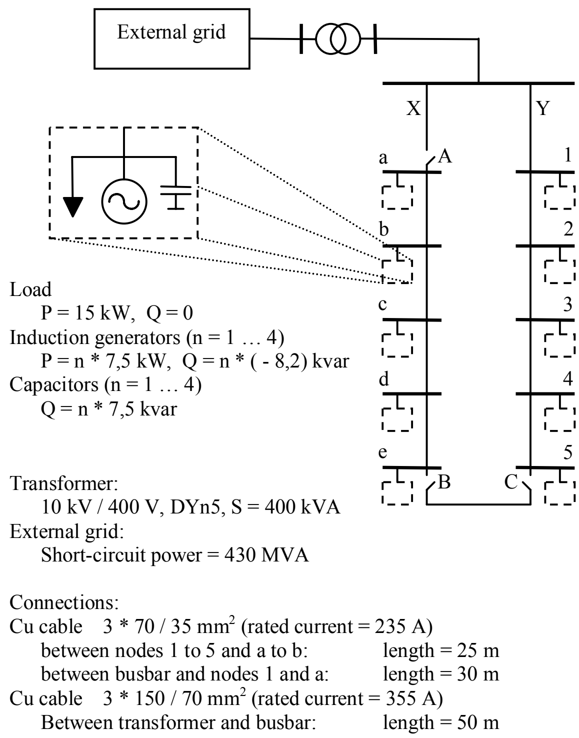


Fig. 1. Distribution network used for simulations

In order to study the problem of possible loss of selectivity, a fault is applied at one of the five nodes of feeder *X*. The current supplied by feeder *Y* is recorded. This is carried out for the four generator configurations. In Fig. 2 to Fig. 5 the results are shown for the situations with one and four generators per cell (dotted line: 4 generators per cell, continuous line: 1 generator per cell). The curves for the two other situations are not shown. They are situated between the drawn curves and have a similar shape. For the asymmetrical faults, the highest phase current is shown.

### *A. Three-Phase Fault*

The results for the three-phase short-circuit are shown in Fig. 2. Currents are lower when the short circuit is closer to the beginning of the feeder. This is because the three phase voltages decrease when a short circuit occurs. When the voltage applied at the terminals of an induction generator is reduced, the power output of the generator is reduced as well.

*B. Line-to-Line Fault*

The results for the line-to-line fault are shown in Fig. 3. For the case of four generators, the difference between a fault at nodes *c* and *d* is large. The distance between these nodes is 25 m. The current decrease is 31 % (from 650 A to 450 A). The curve for the case of one generator has a similar profile: between nodes *b* and *c* the decrease is 45 % (from 220 A to 115A).

*C. Line-to-Ground Fault*

The results for the line-to-ground fault are shown in Fig. 4. The current decreases as the fault is farther away. The change is small. The difference between *a* and *e* when four generators per cell are used, is 100 A.

*D. Double Line-to-Ground Fault*

The results for the grounded phase-to-phase fault are shown in Fig. 5. This figure is similar to Fig. 3. The large current differences are situated between nodes *d* and *e* (four generators per cell, decrease of 37 %) and *c* and *d* (one generator per cell, decrease of 56 %).

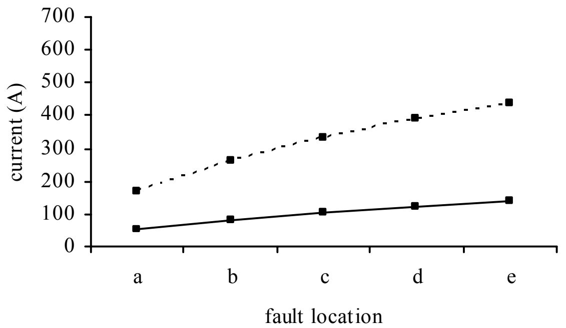


Fig. 2. Three-phase fault in feeder *X*. Current supplied by feeder *Y* as a function of fault location. Dotted line: 4 generators per cell, continuous line: 1 generator per cell.

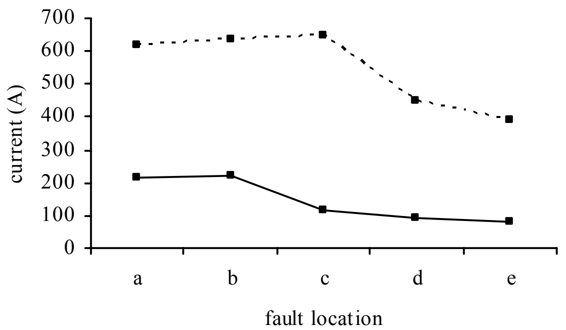


Fig. 3. Line-to-line fault in feeder *X*. Current supplied by feeder *Y* as a function of fault location.

*E. Conclusion*

The fault current supplied by feeder *Y* is higher when more generators are used. However, these examples show that, when induction generators are used, the location of the fault has a strong influence on the fault current supplied by the healthy feeder, except when a line-to-ground fault occurs.

These examples indicate that line-to-line faults and double line-to-ground faults cause the highest current in a neighboring, healthy feeder. They are most likely to cause unnecessary disconnection of a healthy feeder. However, if the protective relay of a faulty feeder is malfunctioning, a healthy feeder should be disconnected after a certain delay.

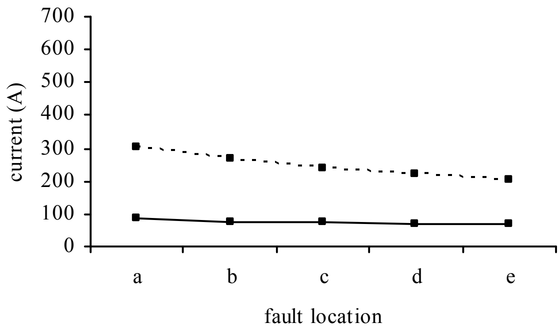


Fig. 4. Line-to-ground fault in feeder *X*. Current supplied by feeder *Y* as a function of fault location.

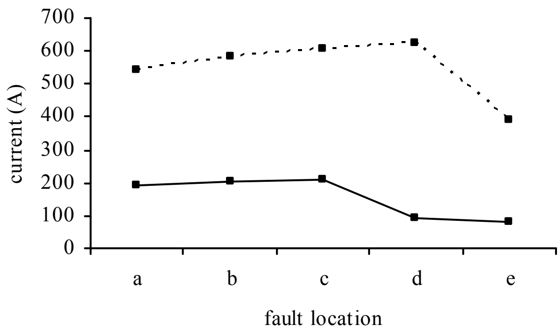


Fig. 5. Double line-to-ground fault in feeder *X*. Current supplied by feeder *Y* as a function of fault location.

## IV. Fault Detection at the Beginning of a Feeder

A second series of simulations is carried out to observe how overcurrent detection at the beginning of a feeder is affected by the presence of induction generators. The analysis is simplified by considering the steady-state fault current, without the generators' transient behavior. In the next section, transient behavior is taken into account.

The system in Fig. 1 is used, with switch *A* opened and switches *B* and *C* closed. At the start of a simulation, an equal number of generators are connected to the feeder in each cell. A disconnection sequence for the generators is programmed before starting the simulation. After 1 s, a short circuit is applied at the end of the feeder (node *a*). At 10 s, the generators at node *a* are disconnected. At 11 s, the generators at node *b* are disconnected, etc. Finally, at 19 s, the last group of generators (at node 1) is disconnected. From then on, current is only supplied by the external grid. The evolution of the current at the beginning of the feeder is recorded. The results are shown in Fig. 6 to Fig. 9. Only the curves for one and four generators are shown. The other two curves are similar and are situated between the curves shown.

After the last generators are disconnected (at 19 s), the short-circuit current, supplied by the grid, is different for the four cases (number of generators per cell). This is because the capacitors (connected in parallel to each generator) are not disconnected.

### A. Three-Phase Fault

Fig. 6 shows the current supplied by the external grid for a three-phase fault. Current decreases as generators are switched off. The difference between the initial and the final current is small: 62 A (- 2.4 %) when four generators per cell are used and 17 A (- 0.7 %) when one generator per cell is used. Total current is higher than 2.5 kA. This indicates induction generators have a very small impact on the current detected at the beginning of a feeder during a three-phase fault.

### B. Line-to-Line Fault

Fig. 7 shows the evolution of the current during a line-to-line fault. Current increases as generators are disconnected. The increase amounts to 540 A (+ 28 %) for the case of four generators per cell and 170 A (+ 8 %) for the case of one generator.

### C. Line-to-Ground Fault

Fig. 8 shows the evolution of the current during a line-to-ground fault. Current increases as generators are switched off. The increase amounts to 340 A (+ 30 %) for the case of four generators per cell and 110 A (+ 8 %) for the case of one generator.

### D. Double Line-to-Ground Fault

Fig. 9 shows the evolution of the current during a double line-to-ground fault. Current increases as generators are switched off. The increase amounts to 320 A (+ 15 %) for the case of four generators per cell and 80 A (+ 4 %) for the case of one generator.

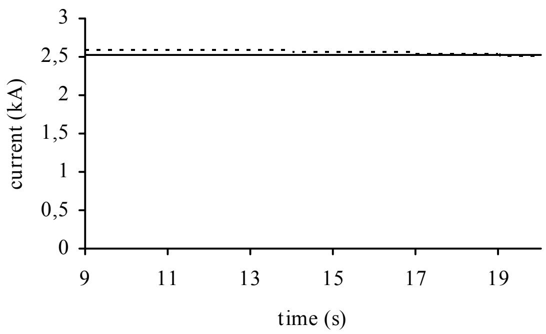


Fig. 6. Three-phase fault. Current supplied by external grid. Dotted line: 4 generators per cell, continuous line: 1 generator per cell.

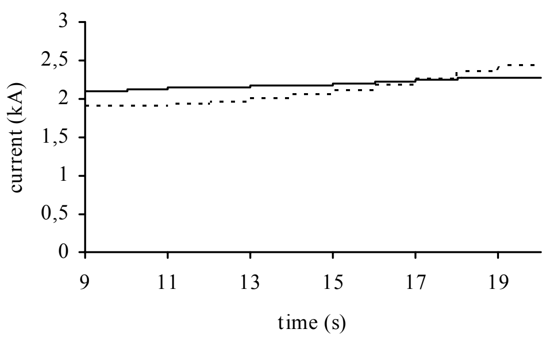


Fig. 7. Line-to-line fault. Current supplied by external grid.

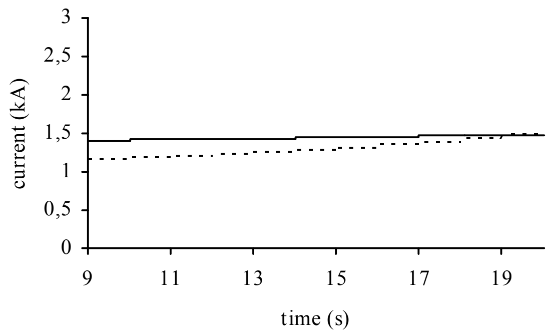


Fig. 8. Line-to-ground fault. Current supplied by external grid.

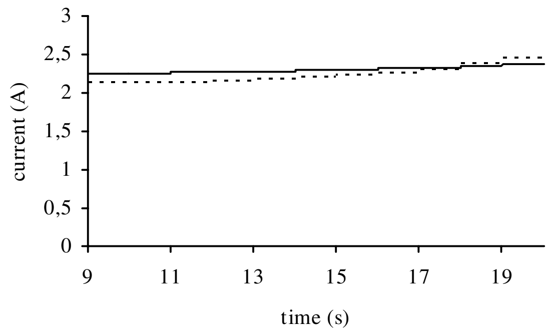


Fig. 9. Double line-to-ground fault. Current supplied by external grid.

### E. Conclusion

The relative change is largest for the line-to-line fault and the line-to-ground fault. For both faults, the increase is about 30 % when four generators per cell are used and 8 % when one generator per cell is used. A step pattern similar to that of Fig. 7, 8 and 9 is observed in the output currents of the generators.

## V. Detailed Study of Fault Detection

In this section a more detailed study of the effect of a local generator on the detection of short-circuit currents is discussed, taking into account the transient behavior of the generator. Disconnection of the generator when a fault occurs is assumed not to happen.

In order to obtain a more general result, a simple distribution feeder is used (Fig. 10). It consists of a voltage source with internal impedance, representing the main grid (15 kV, 50 Hz, $R/X$=0.1 [18], [13]); a distribution transformer $T_1$; a distribution feeder (400 V) consisting of a three-phase cable with a neutral conductor; a passive load (configuration: grounded wye) at the end of the feeder; a generator somewhere along the feeder and a transformer $T_2$ connecting the generator to the feeder.

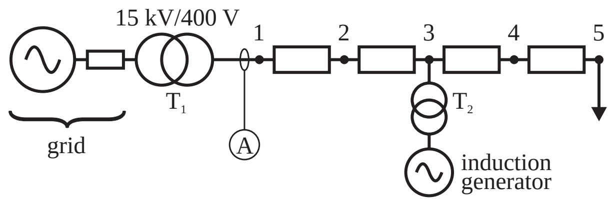


Fig. 10. Outline of the system that is simulated.

Five nodes are defined along the feeder. Nodes 1 to 4 are the possible locations of the generator. The feeder sections between the nodes are of equal length. Short circuits are applied at node 5 (the location of the load). Current is measured between the distribution transformer and node 1. In the following paragraphs, the different aspects of the model and the results are discussed.

### *A. System Parameters*

The feeder is protected against short circuits by a definite-time relay. When the current reaches a certain value, the circuit breaker is activated immediately or with a fixed time delay. In order to assess the effect of the local generator on short-circuit detection, the fault currents resulting from the simulations are analyzed. Interruption of the current is not simulated.

The system is characterized by five independent parameters, for which a range of possible values is chosen, in order to cover a wide range of system configurations. These parameters are the short-circuit power of the grid ($S_{SC}$ = 50, 100, 200, 500 and 1000 MVA), the cross-sectional area of the conductors ($A_C$ = 10, 16, 25, 35, 50, 70, 95, 120, 150, 185, 240 and 300 mm$^2$), the location of the generator (nodes 1 to 4), the relative power of the generator (50 % and 200 % of the rated power of the feeder) and the minimum short-circuit current ($I_{MSC}$). In [12] values for $I_{MSC}$ are given, corresponding to of values for the rated current of protective devices. For the rated currents from 80 A to 500 A, $I_{MSC}$ is 5.5 to 7.8 times higher than the rated current. For simplicity, one factor is used (six) for all cable cross-sections. In order to show the effect of a higher $I_{MSC}$, an alternative factor (twelve) is used as well. This means two groups of configurations are created: one with $I_{MSC}$ equal to 6•$I_R$ and one with $I_{MSC}$ equal to 12•$I_R$. The threshold current of the definite-time relay has to be lower than $I_{MSC}$, in order to detect short-circuit currents. Each combination of parameter values is referred to as a configuration. 1440 configurations can be described with these five parameters.

The values of the parameters of the main grid, the distribution transformer and the feeder cable are determined without taking into account the local generator. Rated power of all elements is derived from $A_C$ of the cables. A rated current ($I_R$) equal to 90 % of the permissible current is assigned to each cross section. With $I_R$, the rated apparent power $S_R$ is calculated. Next, a distribution transformer is selected for each cable section.

The feeder cable consists of four copper conductors: three phase conductors and one neutral (Fig. 11). The conductors are of equal size. The arrangement of the conductors results in unbalanced cable impedance.

Feeder lengths have to be chosen. Because the aim is to determine for which configurations the influence of the local generator on current detection is strongest, maximum feeder lengths are used. In this way, the main grid's contribution to the fault current is minimal and the generator's influence will be strongest. In determining suitable feeder lengths, the local generator is not taken into account. Maximum length is derived from two criteria: a maximum allowed voltage drop of 10 % [19] and a minimum fault current when a short circuit arises at the end of the feeder (node 5). For the fault resistance and the ground resistance, a value of 1 mΩ is used.

Based on these criteria, a feeder length is calculated for each combination of values for $S_{SC}$, $A_C$ and $I_{MSC}$. Each combination of $S_{SC}$ and $A_C$ can be situated in the matrix shown in Fig. 12. In Table I calculated minimum and maximum values for feeder length ($L_F$) and series impedance of the feeder ($R_F$, $X_F$ and $Z_F$) are given.

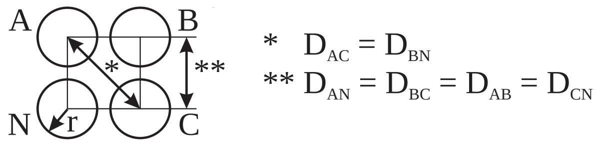


Fig. 11. Arrangement of the three phase conductors (A, B and C) and the neutral conductor (N) of the cable.

| $S_{SC}$ \ $A_C$ | 10 | 16 | 25 | 35 | 50 | 70 | 95 | 120 | 150 | 185 | 240 | 300 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 50 | | | | | | | | | | | | |
| 100 | | | | | | | | | | | | |
| 200 | | | | | | | | | | | | |
| 500 | | | | | | | | | | | | |
| 1000 | | | | | | | | | | | | |

Fig. 12. Matrix of combinations of $S_{SC}$ (MVA) and $A_C$ (mm$^2$). X: used for additional simulations with two and four generators.

The system contains two three-phase transformers: $T_1$ (configuration: HV: delta, LV: grounded wye) and $T_2$ (both sides: grounded wye). Distribution transformers usually supply multiple parallel feeders. Therefore, the choice is made to dimension the distribution transformer for three times the rated power of the feeder. The rated power of the second transformer is equal to that of the generator.

TABLE I
MINIMUM AND MAXIMUM VALUES OF FEEDER CHARACTERISTICS, AND CORRESPONDING CONFIGURATIONS

| | $I_{MSC}$ | Min. value | Configuration MVA ; mm$^2$ | Max. Value | Configuration MVA ; mm$^2$ |
|---|---|---|---|---|---|
| $L_F$ (m) | 6 $I_R$ | 140 | 50-1000 ; 10 | 368 | 200-1000; 150 |
| | 12 $I_R$ | 86 | 50; 10 | 152 | 200-1000; 120 |
| $R_F$ (mΩ) | 6 $I_R$ | 24 | 50; 300 | 285 | 50-1000; 10 |
| | 12 $I_R$ | 9.2 | 50-200; 300 | 178 | 100-200; 10 |
| $X_F$ (mΩ) | 6 $I_R$ | 12 | 50-1000; 10 | 29 | 200-1000; 150 |
| | 12 $I_R$ | 7.5 | 50;10 | 12 | 200-500; 120 |
| $Z_F$ (mΩ) | 6 $I_R$ | 35 | 50; 300 | 285 | 50-1000; 10 |
| | 12 $I_R$ | 13 | 50-200;300 | 179 | 100-200; 10 |

The generator is a four-pole induction generator (400 V, 50 Hz, stator: ungrounded wye). The generator consists of an induction machine and a mechanical power source. The total moment of inertia is estimated by multiplying the inertia of the induction machine by two. The torque applied to the generator is a constant value.

### B. Discussion of Simulation Results

During a short circuit, transient behavior is displayed by the induction generator. In order to take this into account, the system is simulated in the time domain. One simulation is carried out for each combination of $S_{SC}$, $A_C$, $I_{MSC}$, location of the generator, generator size and fault type. This results in a large number of simulations. In order to make a uniform analysis of the impact of the generator on fault detection, the detected current in the system with a local generator is compared to the current detected originally in the system without generator. Because of the way the cable lengths are calculated, the current for each of the four fault types is equal to or higher than $6{\bullet}I_R$ or $12{\bullet}I_R$, respectively, when the generator is not used.

Each simulation results in a time sequence of values. These are converted to RMS values. In order to limit the amount of data to be analyzed, the values at two moments are selected: at 0.1 s and 0.2 s after the start of the fault. Time delays of circuit breakers are situated around these values. In Fig. 13 the result of a simulation of a line-to-line fault is shown.

For the different fault types, without the contribution of a local generator, the currents in the different phases are not equal. For the line-to-line fault (Fig. 13), for instance, this is caused by the current through the load at node 5. Due to the short circuit, the voltages of the two lines concerned are in phase. Consequently the currents through the phases of the load that correspond to the shorted lines are identical and in phase. The fault currents are identical but opposite. The detected current is the sum of the load current and the fault current. As a result, the amplitudes of the detected currents are different, as is shown in Fig. 13 (dashed lines).

When a generator is used and a line-to-line fault or a double line-to-ground fault occurs, the difference between the detected currents is larger, as is shown in Fig. 13 (solid lines). This is caused by the asymmetry of the three-phase voltage at the generator terminals, which results in different phase currents. Because of this, the effect of the generator on the detected current is different for each phase.

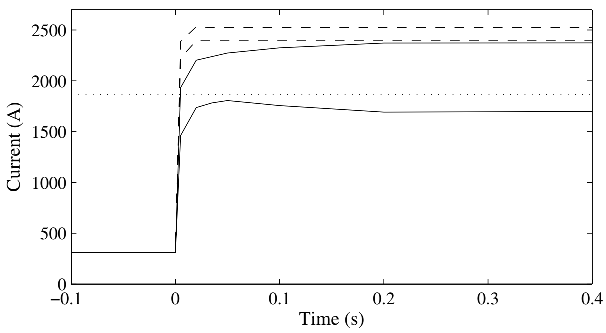


Fig. 13. Detected fault current during line-to-line fault. ($S_{SC}$ = 500 MVA, $A_C$= 120 mm$^2$, double-sized generator at node 2). Solid lines: currents in the two shorted phases. Dashed lines: current without a generator. Dotted line = $I_{MSC}$ = $6{\bullet}I_R$.

It is assumed a three-phase relay and circuit breaker are used. A three-phase disconnection is initiated as soon as the current in one of the phases is sufficiently high. Because of this, configurations for which at least one of the phase currents is high enough, do not pose a fault-detection problem. Configurations that are potentially problematic are those where all phase currents are significantly lower than the current originally detected. In this case, the detected current could be situated in the inverse-time section of the relay's characteristic, instead of the definite-time section, resulting in an unwanted increase in interruption delay.

In the following analysis two comparisons are made. First, the system configurations are identified for which the fault current in each phase is lower than 90 % of the minimum current originally detected, i.e. without the presence of a generator. These configurations are labeled "low-current". This provides a general view of the influence of the generator. Currents will be expressed as a per unit (p.u.) value, with 1 p.u. being the original fault current. In order to outline the sets of configurations with low currents, reference is made to the matrix in Fig. 12. This matrix is repeated four times in Fig. 14, once for each fault type.

Afterwards, a second comparison is made. Currents are compared to $I_{MSC}$. This provides the subset of configurations which are problematic, as in these cases it is possible the circuit breaker does not trip at the desired moment. For this comparison, currents will be expressed as a percentage of $I_{MSC}$, so as to distinguish these values form the p.u. values of the first comparison.

In the following discussion, sets of configurations with the same value for $S_{SC}$ are referred to as rows of the matrix in Fig. 3. Sets with the same value for $A_C$ are referred to as columns. Rows and columns are indicated with the value of the corresponding variable, e.g. row 500 or column 25. Distinction between the instants at 0.1 s and 0.2 s after the start of the fault is made only when there is a considerable difference.

1) *Three-Phase Fault:* For the three-phase fault, no *low-current* situations are found when a half-sized generator is used. For configurations with larger generators, *low-current* situations are found. In Fig. 14a the *low-current* region is indicated for a double-sized generator at node 1 at 0.1 s, for $I_{MSC}$ equal to $6{\bullet}I_R$, i.e. columns 10 to 50 (striped area). When the power of the generator is decreased or the location of the generator is shifted towards node 5, the *low-current* region is reduced towards the smaller cable sizes. The overall minimum is found for a double-sized generator at node 1, in columns 10 and 16, at 0.2 s. For these cases, the phase currents range from 0.79 to 0.81 p.u. For the systems with $I_{MSC}$ equal to $12{\bullet}I_R$ and the generator at node 1, the low-current region at 0.1 s is indicated in Fig. 5a by means of dots. The overall minimum is found for columns 10 and 16 at 0.2 s. Here the phase currents range from 0.85 to 0.87 p.u.

In Table II the minimum detected current compared to $I_{MSC}$ is given for each fault type, for both designs ($I_{MSC}$ =

$6 \cdot I_R$ or $12 \cdot I_R$) and for the half-sized and double-sized generator. For the three-phase fault and for $I_{MSC}$ equal to $6 \cdot I_R$ the detected current does not drop below 100 %. For $I_{MSC}$ equal to $12 \cdot I_R$, the minimum value is 97 %. This means an induction generator does not interfere with short-circuit detection when a three-phase fault occurs.

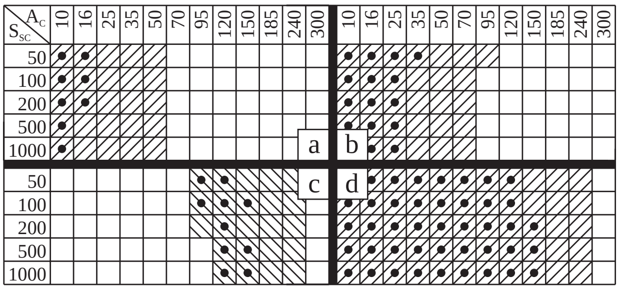


Fig. 14. *Low-current* combinations (< 0.9 p.u.) for a) three-phase, b) line-to-line and d) single line-to-ground fault. Combinations with currents < 0.95 p.u. for c) double line-to-ground fault. Double-sized generator at node 1 at 0.1 s. Striped area: $I_{MSC} = 6 \cdot I_R$, dots: $I_{MSC} = 12 \cdot I_R$.

2) *Line-to-Line Fault:* For the line-to-line fault, no *low-current* situations are found when a half-sized generator is used. For larger generators, *low-current* situations are found. For a double-sized generator at node 1, the *low-current* region consists of columns 10 to 70 (and combination 50 MVA / 95 mm$^2$ at 0.1 s) (Fig. 14b). For the other nodes, no *low-current* region is found.

The two phase currents are lowest for a double-sized generator at node 1, at 0.2 s. The lowest currents are found for the configurations with $A_C$ equal to 10 and 16 mm$^2$ and the combination 50 MVA / 25 mm$^2$. For these cases, the current in one phase is 0.67 p.u. and in the other phase 0.84 to 0.85 p.u. For the systems with $I_{MSC}$ equal to $12 \cdot I_R$, the *low-current* region at 0.1 s consists of columns 10 to 25 and the combination 50 MVA / 35 mm$^2$ (Fig. 5b). The overall minimum is found for the combination 500 MVA / 10 mm$^2$, at 0.2 s: the phase currents are 0.76 and 0.87 p.u.

For a double-sized generator in a system with $I_{MSC}$ equal to $6 \cdot I_R$, the detected currents of one phase are lower than $I_{MSC}$, except for several configurations situated in columns 120 to 300. The minimum current is 80 % (Table II). There are no configurations for which both currents are lower than 100 %, resulting in adequate fault detection. For the systems with $I_{MSC}$ equal to $12 \cdot I_R$, for the configurations in columns 10 and those with $S_{SC}$ from 50 to 200 MVA in column 16, with a double-sized generator at node 1, both currents are lower than 90 %. For these cases, the maximum of both phase currents is lowest at 50 MVA / 10 mm$^2$. The currents are 77 and 88 %. Here the transition from the inverse-time section to the definite-time section of the relay's characteristic should be below 88 % of $12 \cdot I_R$, in order to keep the fault current during a short circuit in the definite-time section.

3) *Double Line-to-Ground Fault:* For the double line-to-line fault, no currents lower than 0.9 p.u. are found when a half-sized generator is used. For the double-sized generator, a small number of *low-current* combinations are found. In order to provide more information in Fig. 14c, the combinations indicated are those with both currents lower than 0.95 p.u. instead of 0.9 p.u. With $I_{MSC}$ equal to $6 \cdot I_R$, the configuration for which the maximum of both phase currents is lowest, is 50 MVA / 150 mm$^2$ / node 1. The currents are 0.78 p.u. and 0.9 p.u. With $I_{MSC}$ equal to $12 \cdot I_R$, the configuration for which the maximum of both phase currents is lowest, is 100 MVA / 120 mm$^2$ / node 1. The currents are 0.85 p.u. and 0.93 p.u.

There are no cases for which both currents are lower than $6 \cdot I_R$ or $12 \cdot I_R$, respectively. These findings lead to the conclusion that there is no detection problem when a double line-to-ground fault occurs.

TABLE II LOWEST CURRENTS, IN % OF $I_{MSC}$. TIME = 0.2 S. *: HALF-SIZED GENERATOR, **: DOUBLE-SIZED GENERATOR

| Fault | $I_{MSC}$ | Generator at node | Half-sized Generator | Double-sized generator |
|---|---|---|---|---|
| | | | Current [%] | Current [%] |
| Three-phase | 6 $I_R$ | 1 | 128 | 110 |
| | 12 $I_R$ | 1 | 109 | 97 |
| Line-to-line | 6 $I_R$ | 3 * / 2 ** | 113 | 80 |
| | 12 $I_R$ | 4 * / 3 ** | 96 | 76 |
| Double line-to-ground | 6 $I_R$ | 2 * / 1 ** | 113 | 88 |
| | 12 $I_R$ | 1 | 95 | 81 |
| Single line-to-ground | 6 $I_R$ | 1 | 94 | 81 |
| | 12 $I_R$ | 1 | 94 | 86 |

4) *Single Line-to-Ground Fault:* When a single line-to-ground fault occurs, the detected current for all configurations is lower than the current without the presence of a generator. For configurations with $I_{MSC}$ equal to $6 \cdot I_R$ and a half-sized generator, the currents lie between 0.94 and 0.99 p.u. For a double-sized generator, currents lie between 0.79 and 0.95 p.u. For configurations with the generator at node 1, the low-current region consists of columns "10" to "240", as is shown in Fig. 14d. When the generator is moved away from node 1, the low-current region becomes smaller. For configurations with $I_{MSC}$ equal to $12 \cdot I_R$ and a half-sized generator, the currents lie between 0.96 and 1 p.u. For a double-sized generator, currents lie between 0.84 and 0.96 p.u.

For configurations with $I_{MSC}$ equal to $6 \cdot I_R$ and with a half-sized generator, the detected current is lower than 100 % for cable sections of 70 mm$^2$ and higher. For nodes 3 and 4 some configurations in columns "240" and "300" result in currents that are higher than $I_{MSC}$. For both possible values of $I_{MSC}$ the minimum current is 94 %.

Compared to $I_{SCM}$, for a double-sized generator the detected current is lower than 100 % for cable sections of 35 mm$^2$ and larger for nodes 1 and 2. For the other two nodes, this region starts at column "50". Currents that are lower than 90 % are found in columns "50" to "185" for nodes 1 and 2. This region becomes smaller if the generator is moved further away from the transformer. The minimum current is 81 % (node 1, 50 MVA, 70 mm$^2$). For the configurations with $I_{MSC}$ equal to $12 \cdot I_R$, the minimum current is 86 % (node 1, 100 MVA, 25 mm$^2$).

Because detected current is lower than 90 % of $I_{MSC}$

for half of the configurations with a generator at node 1 or 2, the ground current $I_G$ is considered as well ($I_G = I_A + I_B + I_C + I_N$). When $I_G$ is compared to its value without the contribution of the generator, it is found that for configurations with $I_{MSC}$ equal to $6 \cdot I_R$ there are configurations for which $I_G$ is affected negatively. For a generator at node 1 all configurations result in lower current. For a half-sized generator the minimum current is 97 % of the original $I_G$ (50 MVA / 185 mm$^2$). For a double-sized generator, the minimum current is 90 % (50 MVA / 300 mm$^2$). For configurations with $I_{MSC}$ equal to $12 \cdot I_R$, the minimum current is 99 % for a half-sized generator and 96 % for a double-sized generator. These results show that during a fault $I_G$ remains high when an induction generator is used locally. As a result, the ground current can be used to detect a single line-to-ground fault.

## VI. Final Conclusion

Protection of feeders and equipment becomes more complex when relatively large amounts of power are generated in distribution networks. Simulation results have been presented concerning the effect of local induction generators on protection selectivity and short-circuit detection by a relay at the beginning of a distribution feeder. Regarding selectivity in a system with two parallel feeders, the results indicate that the contribution to the fault current from a healthy feeder are largest when a line-to-line fault or a double line-to-ground fault occurs. Regarding the fault current detected at the beginning of a feeder, both sets of simulations indicate that this current is lowest when a line-to-line fault or a line-to-ground fault occurs. Depending on the relay settings, this can result in a detection problem. For the single phase-to-ground fault, adequate detection can be achieved by measuring the ground current. For the three-phase fault and the double line-to-ground fault, one phase current is always sufficiently high.

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