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Short-circuit calculations in networks with distributed generation

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Abstract

Fault level considerations may be an inhibiting factor for the interconnection of distributed generation (DG) to the network, particularly at the medium voltage level. In this paper, the latest edition of the IEC 60909 Standard is applied for the calculation of the resulting fault level in medium and low voltage distribution networks with DG. First, an outline of the IEC calculation methodology is presented, including all relevant equations for DG cases studies. Then the short-circuit contribution of the various DG types is extensively discussed. The application of the methodology is demonstrated on a study case medium voltage distribution network, which includes all representative types of DG sources. Emphasis is placed on the contribution of the upstream system, which is the dominant source of short-circuit current. A discussion is also included on potential measures for fault level reduction.

Keywords: Short-circuit current; Fault level; Distributed generation (DG); Distribution networks; IEC 60909

1. Introduction

Distribution networks are characterized by a design short-circuit capacity, i.e. a maximum acceptable fault current, related to the switchgear used and to the thermal and mechanical withstand capability of the equipment and constructions. A fundamental requirement for the connection of distributed generation (DG) resources to the network, besides voltage regulation and power quality constraints [1], is that the total fault level, determined by the combined short-circuit contribution of the upstream grid and the DG, should remain below the network design value. This constraint is often the main inhibiting factor for the interconnection of new DG installations [2,3] to existing grids.

In medium voltage (MV) and low voltage (LV) radial networks, the fault current contribution of the upstream grid is practically determined by the short-circuit impedance of the HV/MV or MV/LV transformers, which is selected as low as possible to improve voltage regulation and the overall power quality performance of the network. Hence, the short-circuit capacity of existing distribution networks, particularly at the MV level, is close to the design value, leaving little margin for the connection of even moderate amounts of DG.

Short-circuit calculations for switchgear selection and protection coordination are performed according to established national and international practices, most important and widely accepted being the IEC and ANSI/IEEE Standards [4–6]. The IEC Standard 60909 [7–11], which is applied in this paper, encompasses a variety of network voltage levels, configurations, operating conditions and generating and load equipment, but remains focused on the traditional power system paradigm with large centralized conventional generation. It provides no guidance on the fault contribution of small and medium size DG installations, particularly for recent and emerging technologies, involving sources with power electronics converter interfaces to the grid.

The objective of this paper is a twofold one. First, it attempts to provide a concise and easy to use guide for the application of IEC 60909 for fault level studies in MV and LV radial distribution networks, where DG is connected. The attention is focused on networks where the three-phase short-circuit results in maximum fault current. Then, it includes recommendations for the calculation of the fault current contribution of the various

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types of DG encountered today. In Section 2, an overview of the IEC Standard is presented, followed by the required application formulae and details. The fault level calculation procedure is outlined in Section 3 and guidelines are provided for the representation of the main DG source types in Section 4. In Section 5, the application of the methodology is demonstrated on a study case network with DG installations of various types. A discussion follows in Section 6 on practically implementable solutions for the reduction of the fault level.

2. Overview of the IEC 60909 Standard

2.1. Basic principles

The IEC 60909 Standard is applicable for the calculation of short-circuit currents in 50 or 60 Hz three-phase ac systems. The equivalent voltage source method is adopted, permitting calculation of fault currents using only the nominal voltage of the system and rated values of the equipment. Several simplifications are inherent in the calculation procedure. To enhance the accuracy of the results and account for system operating conditions (pre-fault voltages, load level, transformer tap-changer positions, etc.), the use of various impedance correction factors is recommended in the Standard.

The short-circuit current is always considered as the sum of an ac symmetrical component and an aperiodic (dc) decaying component. A fundamental distinction is made between "far-from-generator" and "near-to-generator" faults. In the former, the short-circuit current includes a time-decaying symmetrical ac component, whereas in the latter case the ac component remains constant in time. Maximum and minimum values of the short-circuit currents are calculated in the Standard, for balanced and unbalanced faults. Different approaches are adopted according to network configuration – radial or meshed – and to fault location.

In the presence of multiple fault current sources within the network, the total fault current is the vector sum of all contributions (system transformer, local generation and motor loads). However, in radial systems the algebraic summation is also permitted, which simplifies the calculations and provides results on the safe side.

Here the objective is to calculate the maximum short-circuit capacity in distribution networks with DG. This is performed for three-phase faults, which provide the maximum fault current when the network neutral is earthed directly or via an earth-fault current limiting impedance (in networks with different earthing arrangements it is possible that other types of faults, such as single-line-to-ground, may yield the highest fault current). "Far-from-generator" conditions are assumed regarding the contribution of the upstream network (but not for the local DG sources).

2.2. Short-circuit current definitions

The initial symmetrical short-circuit current, I_k'' is the rms value of the ac symmetrical component of a prospective short-circuit current. The initial symmetrical short-circuit power, S_k'', known also as the fault level, is defined as

$$S_k'' = \sqrt{3} I_k'' U_\mathrm{n} \tag{1}$$

where U_n is the nominal voltage at the short-circuit location.

To account for the various effects of the time-decaying short-circuit current, several characteristic values are defined in Ref. [7] and briefly described in the following.

- The peak short-circuit current, i_p, determined as the maximum instantaneous value of the fault current:

$$i_\mathrm{p} = \kappa \sqrt{2} I_k'' \tag{2}$$

The factor κ is given by the following expression:

$$\kappa = 1.02 + 0.98\,\mathrm{e}^{-R/X} \tag{3}$$

where R and X are the real and the imaginary part of the equivalent short-circuit impedance $\underline{Z}_k$ at the short-circuit location.

- The decaying aperiodic component, i_dc, of the short-circuit current, determined as the average between the top and bottom envelope curve of the fault current:

$$i_\mathrm{dc} = \sqrt{2} I_k''\,\mathrm{e}^{-2\pi f t\,R/X} \tag{4}$$

where f is the nominal frequency, t the time and R/X is the same ratio as in Eq. (3).

- The symmetrical short-circuit breaking current, I_b, is the rms value of an integral cycle of the symmetrical ac component of the current, at the instant of contact separation of the first pole to open in a switching device. For far-from-generator faults, as well as for short-circuits in meshed networks, I_b is assumed equal to I_k''. In case of near-to-generator short circuits in non-meshed networks, the symmetrical breaking currents of synchronous and asynchronous machines (generators or motors) are, respectively given by:

$$I_\mathrm{b} = \mu I_k'' \tag{5}$$

$$I_\mathrm{b} = \mu q I_k'' \tag{6}$$

Factor μ is a function of the ratio I_k''/I_rG, where I_rG is the rated current of the synchronous machine. Factor q is a function of the ratio P_rM/p where P_rM is the rated active power and p the number of pole-pairs of the asynchronous machine. Both factors depend on the considered minimum breaking time, t_min, and specific relations and diagrams are provided in the IEC Standard. A safe but conservative approximation would be $\mu = 1$, $\mu q = 1$.

- The steady-state short-circuit current, I_k, is the rms value of the current after the decay of the transient components. For generators:

$$I_{k\,\max} = \lambda_{\max} I_\mathrm{rG} \tag{7}$$

where the factor $\lambda_{\max}$ is obtained graphically. For far-from generator faults, $I_k = I_k''$.

- The thermal equivalent short-circuit current, I_th, is defined as the rms value of a non-decaying current, having the same

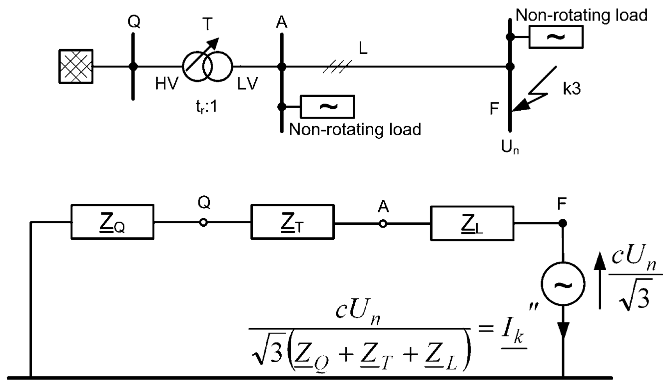

Fig. 1. Illustration of the equivalent voltage source method [7].

thermal effect and duration as the actual current:

$$\int_0^{T_k} i^2 \, dt = I''^2_k (m+n) = I^2_{th} T_k \tag{8}$$

T_k is the duration of the short-circuit current. Factors m and n, obtained graphically, are used for the thermal effect of the dc and the ac component, respectively.

2.3. Calculation of the initial short-circuit current, I''_k

The calculation of the various short-circuit currents defined in the previous section is based on the computation of the initial symmetrical short-circuit current, I''_k.

The IEC 60909 calculation method determines the currents at the short-circuit location F using the equivalent voltage source $cU_n/\sqrt{3}$, defined as the voltage of an ideal source applied at the short-circuit location in the positive-sequence system, whereas all other sources in the system are ignored (short-circuited). The equivalent voltage source method, proposed in Ref. [7], is illustrated in Fig. 1.

The voltage factor c accounts for variations of the system voltage and should be in agreement to the permitted voltage deviations in the network. When calculating maximum short-circuit currents, the value $c_{max} = 1.1$ is recommended in Ref. [7] for all voltage levels.

For symmetrical three-phase short-circuits, the initial symmetrical current is calculated by:

$$I''_k = \frac{cU_n}{\sqrt{3} Z_k} \tag{9}$$

where Z_k is the magnitude of the equivalent short-circuit impedance $\underline{Z}_k$ of the upstream grid (essentially its Thevenin impedance) at the short-circuit location F (Fig. 1).

In the case of unbalanced short-circuits the calculation employs the symmetrical component method. The fault type which results in the highest current depends on the sequence impedances $\underline{Z}_{(1)}$, $\underline{Z}_{(2)}$ and $\underline{Z}_{(0)}$ at the fault location (subscripts (1), (2) and (0) denote positive, negative and zero-sequence quantities). When $\underline{Z}_{(0)} > \underline{Z}_{(1)} = \underline{Z}_{(2)}$, e.g. as in HV/MV substations with resistance grounded MV neutral, the highest fault currents occur for three-phase short circuits, which are dealt with in this paper. In networks with different neutral earthing schemes, unbalanced earth faults may provide the highest fault current.

According to IEC 60909, in non-meshed networks, the initial symmetrical current at the short-circuit location is given by the phasor sum of the individual partial short-circuit currents (i.e. the individual source contributions). In meshed networks, the short-circuit impedance $\underline{Z}_k = \underline{Z}_{(1)}$ is determined by network reduction techniques, using the positive-sequence short-circuit impedances of the system components.

2.4. Short-circuit impedances

As mentioned in the previous section, the equivalent voltage source $cU_n/\sqrt{3}$ is the only active source in the system. The upstream network and all synchronous and asynchronous machines are replaced by their internal impedances. Since the paper deals only with three-phase faults, all impedances are positive-sequence ones.

In the following of the paper, indices Q, T, G and M stand for network, transformer, synchronous (generator) and asynchronous (motor) machine, respectively. Subscripts r and n stand for rated and nominal values, while t stands for values referred to the voltage level at the short-circuit location. Superscript b denotes maximum known values before the short circuit. Lower case letters denote per unit quantities, on the rated values of the equipment.

- The equivalent impedance $\underline{Z}_Q = R_Q + jX_Q$ of the upstream network at the feeder connection point Q is determined from the available fault current at this point, I''_{kQ} (i.e. the short-circuit capacity of the system):

$$Z_Q = \frac{cU_{nQ}}{\sqrt{3} I''_{kQ}} \tag{10}$$

For networks with a nominal voltage higher than 35 kV, the IEC Standard suggests $R_Q = 0$. In all other cases, it recommends $R_Q/X_Q = 0.1$ as a safe assumption.

- The short-circuit impedance $\underline{Z}_T = R_T + jX_T$ of a transformer with or without an on-load tap-changer (OLTC) is calculated using:

$$Z_T = \frac{u_{kr}}{100} \cdot \frac{U^2_{rT}}{S_{rT}} \tag{11}$$

$$R_T = \frac{u_{Rr}}{100} \cdot \frac{U^2_{rT}}{S_{rT}} = \frac{P_{krT}}{3 I^2_{rT}} \tag{12}$$

$$X_T = \sqrt{Z^2_T - R^2_T} \tag{13}$$

where u_{kr} is the short-circuit voltage of the transformer (i.e. its series impedance in %), u_{Rr} the rated resistive component of the short-circuit voltage (in %) and P_{krT} the load losses at rated current. Eqs. (11)–(13) are also applicable to short-circuit current limiting reactors.

- The impedance $\underline{Z}_L = R_L + jX_L$ of overhead lines and cables is calculated from conductor and line geometry data [9] and it is typically known for standard line types.

- Synchronous generators are replaced by their impedance

$$\underline{Z}_{\mathrm{G}} = R_{\mathrm{G}} + jX''_{\mathrm{d}} \tag{14}$$

where X''_{d} is the subtransient reactance.

- For power station units with synchronous generators connected to the network through unit transformers, the following impedance is used, referred to the HV side:

$$\underline{Z}_{\mathrm{S}} = t_{\mathrm{r}}^2 \underline{Z}_{\mathrm{G}} + \underline{Z}_{\mathrm{THV}} \tag{15}$$

where t_{r} is the rated transformation ratio of the unit transformer.

- The impedance $\underline{Z}_{\mathrm{M}} = R_{\mathrm{M}} + \mathrm{j}X_{\mathrm{M}}$ of asynchronous motors is given by

$$Z_{\mathrm{M}} = \frac{1}{I_{\mathrm{LR}}/I_{\mathrm{rM}}} \cdot \frac{U_{\mathrm{rM}}}{\sqrt{3} I_{\mathrm{rM}}} = \frac{1}{I_{\mathrm{LR}}/I_{\mathrm{rM}}} \cdot \frac{U_{\mathrm{rM}}^2}{S_{\mathrm{rM}}} \tag{16}$$

where $I_{\mathrm{LR}}/I_{\mathrm{rM}}$ is the ratio of locked-rotor to rated current of the machine. The ratio $R_{\mathrm{M}}/X_{\mathrm{M}}$ is evaluated from equivalent circuit data. Typical values are also available depending on the rated power and voltage of the motor.

- Reversible static converter-fed drives are treated in IEC 60909 in the same way as asynchronous motors, with $I_{\mathrm{LR}}/I_{\mathrm{rM}} = 3$ and $R_{\mathrm{M}}/X_{\mathrm{M}} = 0.1$. All other static converters are ignored for the calculation of the fault currents.
- Shunt capacitors and non-rotating loads are ignored.
- When multiple voltage levels exist in the network, voltages, currents and impedances are converted to the voltage level at the short-circuit location, using the rated transformation ratio t_{r} of the transformers involved.

2.5. Correction factors

To compensate for the various simplifying assumptions of the methodology, IEC 60909 introduces impedance correction factors for transformers (K_{T}), synchronous generators (K_{G}) and power station units (K_{S} and K_{SO}), which multiply the respective impedances in all calculation formulae:

$$K_{\mathrm{T}} = 0.95 \cdot \frac{c_{\max}}{1 + 0.6 x_{\mathrm{T}}} \tag{17}$$

$$K_{\mathrm{T}} = \frac{U_{\mathrm{n}}}{U^b} \cdot \frac{c_{\max}}{1 + x_{\mathrm{T}}(I_{\mathrm{T}}^b/I_{\mathrm{rT}}) \sin \varphi_{\mathrm{T}}^b} \tag{18}$$

$$K_{\mathrm{G}} = \frac{U_{\mathrm{n}}}{U_{\mathrm{rG}}} \cdot \frac{c_{\max}}{1 + x''_{\mathrm{d}} \sin \varphi_{\mathrm{rG}}} \tag{19}$$

$$K_{\mathrm{S}} = \frac{U_{\mathrm{nQ}}^2}{U_{\mathrm{rG}}^2} \cdot \frac{U_{\mathrm{rTLV}}^2}{U_{\mathrm{rTHV}}^2} \cdot \frac{c_{\max}}{1 + |x''_{\mathrm{d}} - x_{\mathrm{T}}| \sin \varphi_{\mathrm{rG}}} \tag{20}$$

$$K_{\mathrm{SO}} = \frac{U_{\mathrm{nQ}}}{U_{\mathrm{rG}}(1 + p_{\mathrm{G}})} \cdot \frac{U_{\mathrm{rTLV}}}{U_{\mathrm{rTHV}}} \cdot (1 \pm p_{\mathrm{T}}) \cdot \frac{c_{\max}}{1 + x''_{\mathrm{d}} \sin \varphi_{\mathrm{rG}}} \tag{21}$$

Eq. (17) is a simplified form of Eq. (18), derived from statistical data of transformers, which does not rely on the pre-fault operating conditions. Eqs. (20) and (21) are used for power station units with transformers equipped with on-load and off-load tap-changers, respectively.

The voltage factor $c_{\max}$ in Eqs. (17)–(21) is determined according to the equipment rated voltage (not the voltage at the fault location). The factor $(1 \pm p_{\mathrm{G}})$, where p_{G} is the permitted over-voltage of the generator, corresponds to the maximum and minimum transformation ratio. In Eq. (18) $\sin \varphi$ is positive for a lagging power factor of the transformer (absorbing VAr from the feeder). In Eqs. (19)–(21) $\sin \varphi$ is positive for a leading power factor of the generator (generating VAr).

The impedance correction factors of Eqs. (17)–(21) are derived by comparing the calculation results of the equivalent voltage source method to those obtained by the superposition method, based on Thevenin's principle. Various approximations are applied to derive these expressions (such as $R \ll X$, $\sqrt{1 + 2x'' \sin \varphi + x''^2} \cong 1 + x'' \sin \varphi$ and others based on statistical data and operating practice). Rated operating conditions are assumed to obtain maximum fault currents.

3. Fault level calculation in networks with DG

3.1. General

In distribution networks with DG, the requirement of not exceeding the design short-circuit capacity should be satisfied at every point of the network, under maximum fault current conditions. In typical radial networks, fed by a HV/MV (or MV/LV) substation, this condition normally needs to be checked at the MV (or LV) busbars of the substation, because the upstream grid provides the dominant contribution, which rapidly diminishes downstream the network due to the series impedance of the lines. The contribution of individual DG sources, on the other hand, reduces to a much smaller degree at remote network nodes, because their internal impedance is relatively high compared to the impedance of the network lines. Therefore, short-circuit current calculations normally need to be performed at the secondary busbars of the substation, regardless of the adopted DG interconnection scheme (connection to an existing feeder or directly to the busbars via a dedicated line [1]).

In any case, the resulting fault level is the phasor sum of the maximum fault currents from the upstream grid, through the step-down transformer, and the various generators (and possibly motors) connected to the distribution network. The grid contribution is easily calculated according to IEC 60909. The contribution of many novel DG source types, on the other hand, is not addressed in the Standard and several assumptions need to be made, as discussed in the following.

3.2. Contribution of the upstream grid

The short-circuit current contribution of the grid (Fig. 2) is calculated using the following expression:

$$\underline{I}''_k = \frac{cU_{\mathrm{n}}}{\sqrt{3}(\underline{Z}_{\mathrm{Q_t}} + \underline{Z}_{K_{\mathrm{T}}})} = \frac{cU_{\mathrm{n}}}{\sqrt{3}(\underline{Z}_{\mathrm{Q}}/t_{\mathrm{r}}^2 + K_{\mathrm{T}}\underline{Z}_{\mathrm{TLV}})} \tag{22}$$

where impedances $\underline{Z}_{\mathrm{Q}}$ and $\underline{Z}_{\mathrm{T}}$ are given by Eqs. (10)–(13) and the correction factor K_{T} from Eqs. (17) or (18).

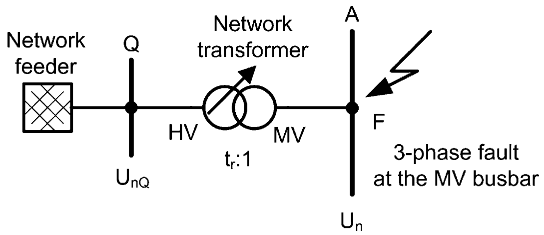

Fig. 2. Upstream grid contribution to a fault at the substation busbars.

Regarding $\underline{Z}_Q$ a typical assumption is $R_Q/X_Q = 0.1$. However, in systems with long transmission lines higher values are possible. The resistive part of the transformer impedance, $\underline{Z}_T$, becomes negligible as the transformer size increases. If not given, it may be ignored ($u_{Rr} = 0$).

Although the actual transformation ratio t and the transformer impedance depend on the tap position, values for rated taps are used in Eq. (22). This is recognized in IEC 60909 and partly compensated for by the correction factor K_T, which is evaluated by Eqs. (17) or (18), the former being more commonly used. This is further discussed in Section 4.

3.3. Contribution of DG stations

Currently, large DG penetrations in MV distribution networks are due to the connection of wind turbines (WT), as well as of medium size industrial combined heat and power (CHP) installations and biomass/biogas fired plants (typically in the 1–10 MW range). In certain areas with favorable hydrological conditions concentrations of small hydroelectric plants (SHEP) may also appear. In LV networks, penetration of DG can be expected in the near future from small CHP units and photovoltaics (PVs). At present, fault level considerations are not a primary concern at the LV level, although under certain (but rather uncommon) conditions they might become.

Regarding short-circuit current, four main types of DG stations are distinguished in the following, based on the type of generator or power converter utilized. The approach presented in this subsection constitutes an extension of the IEC 60909 methodology, not included in the Standard.

3.3.1. Type I: synchronous generators directly coupled to the grid (e.g. SHEP, CHP)

For synchronous generators there are explicit provisions in IEC 60909. With reference to Fig. 3, their short-circuit current contribution is given by

$$\underline{I}_k'' = \frac{cU_n}{\sqrt{3}(\underline{Z}_G + \underline{Z}_T + \underline{Z}_L + \underline{Z}_R)} \tag{23}$$

where all impedances of the generator (G), transformer (T) (if any), interconnecting line (L) and series reactor (R) (if any) are referred to the nominal voltage at the location of the fault.

For synchronous generators connected directly to the grid, Eqs. (14) and (19) apply for the generator impedance and for the correction factor K_G. $R_G = 0.07X_d''$ and $R_G = 0.15X_d''$ are quoted in Ref. [7] for generators with rated voltage <1 kV and >1 kV, respectively. If the generator is connected via a unit transformer, Eqs. (15) and (21) apply, where p_G and p_T may be disregarded ($p_G = p_T = 0$), if specific data are unavailable.

Contractual obligations, voltage regulation issues and network losses considerations usually dictate a DG operating power factor (p.f.) in the range of 0.95 lagging to 0.95 leading. This should be observed when applying Eqs. (19)–(21), because the rated p.f. of the synchronous generator itself may be significantly different (e.g. 0.80–0.85 leading), in order not to overestimate its fault contribution.

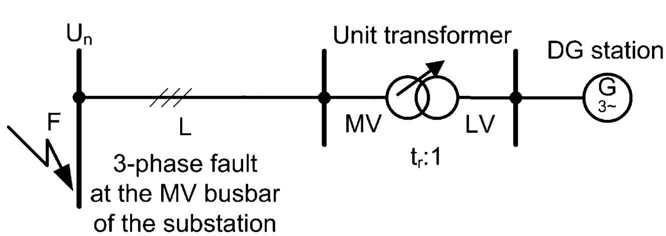

Fig. 3. DG station contribution to a fault at the substation busbars.

3.3.2. Type II: asynchronous generators directly coupled to the grid (e.g. constant speed WTs, small SHEP)

The initial symmetrical short-circuit current of an induction generator is given by Eq. (23). In IEC 60909 reference is made only to asynchronous motors, for which indicative parameter values are also provided. However, the calculation principle is identical and directly applies to generators as well. Hence, the generator impedance Z_G is given by Eq. (16), being essentially the locked-rotor impedance of the machine. In the absence of specific data, $I_{LR}/I_{rG} = 8$ and $R_G = (0.10–0.15)X_G$ are suggested, depending on the size of the generator (these values differ from indicative data provided in IEC 60909 for motors).

When a transformer is used for the connection of the generator, Eqs. (11)–(13) and (17) apply. For MV/LV transformers, the short-circuit voltage is $u_{kr} = 4–6\%$ and its resistive component $u_{Rr} = 1.0–1.5\%$. For the conversion of impedances to the nominal voltage at the fault location (MV level), the rated transformation ratio t_r is to be used. Nevertheless, the use of the maximum transformation ratio $t_r(1 + p_T)$ (for the highest tap position of the step-up transformer) should also be considered, because the voltage at the point of connection of the generator to the MV network is likely to be increased, due to the reverse power flow on the interconnecting line.

3.3.3. Type III: doubly fed asynchronous generators, with power converters in the rotor circuit (variable speed WTs)

Doubly fed induction generators (DFIGs) are extensively used in modern variable speed wind turbines and their analysis has been the subject of several publications [12–16]. Due to the reduced rating of the rotor converter (∼30% of the rated power) and its limited overcurrent capability, the fault current contribution of a DFIG is roughly determined by its stator current. A power electronics device known as a crowbar [16,17] shorts the generator rotor terminals to protect the converters, if an overvoltage or overcurrent situation is detected, that exceeds the converter withstand capability.

The response of the DFIG in the case of a short circuit depends on the control of the rotor-side ac/dc converter, its overload capability and the operation of the crowbar protection. Although measured data are very scarce regarding the maximum short-circuit current contribution, in this respect the DFIG can be roughly approximated as a conventional asynchronous generator (Type II), as it is discussed in the following.

After the occurrence of a fault, high voltages and currents are developed in the rotor winding, which may trigger the crowbar protection, shorting the rotor terminals. In such a case, the behavior of the machine until its disconnection from the grid is identical to a conventional asynchronous generator. This applies to DFIGs without special provisions for low voltage ride-through.

The fault ride-through requirements recently imposed by utilities on new wind farms [18,19], although not always applicable to installations connected to the distribution network, have brought about some change in the design and control of the machines. According to the design of one manufacturer [20], the stator of the machine is disconnected in a few cycles after the fault (30–50 ms according to Ref. [20]), while the rotor converter remains in operation to keep the generator magnetized. After restoration of the voltage, the generator is resynchronized to the grid, continuing its operation. The maximum output current before tripping the stator may reach 5 p.u. [20], which is very similar to the contribution of a conventional induction generator, if the step-up transformer impedance is taken into account. Other manufacturers consider application of modified ("active") crowbars, which protect the converters and maintain control of the generator during the fault, as well as oversized rotor-side converters. Unpublished information obtained from such manufacturers suggests that, in this case too, the WT may be approximated as a Type II generator, for its maximum fault current (although in certain cases this may yield pessimistic results). Large fault currents are also obtained by simulation in the available literature on the subject (e.g. Ref. [14]), while short-circuit current plots included in Ref. [21] indicate also a similar current magnitude.

Based on the above reasoning, it is suggested that DFIGs are treated as conventional (Type II) generators when calculating their maximum fault current contribution, in which case Eqs. (11)–(13), (16) and (17) apply. Notably, if breaking currents are of interest, a safe-side assumption would be to consider that the units remain connected for at least 100 ms, to include their contribution (properly reduced after 5 cycles) in the instantaneous breaking duty of MV switchgear. A notable exception to this treatment may exist for DFIGs equipped with fast stator disconnection devices (static switches), capable of operating within the first half-cycle following the fault, which may limit their peak current contribution [21]. In such a case, the WT contribution to the fault would essentially comprise the current of the grid-side converter of the rotor circuit, which is well below the rated current. Hence, a differentiation may be required for WTs capable of very fast short-term interruption of the stator circuit ([21]), as permitted in the new edition of the E.ON Grid Code [22], although such provisions do not currently apply to smaller stations, connected to the distribution network.

3.3.4. Type IV: power converter interfaced units, with or without a rotating generator (e.g. variable speed WTs, PVs, microturbines)

Sources interfaced to the network via a dc/ac grid-side converter present identical characteristics with respect to their expected short-circuit current contribution, regardless of the primary energy source or prime mover type. For the representation of such sources, the provisions of IEC 60909 for reversible static converter-fed drives could be applied, treating these sources as asynchronous machines, with $I_{LR}/I_{rM} = 3$ and $R_M/X_M = 0.1$, which is equivalent to assuming a 3 p.u. initial short-circuit current, decaying subsequently to zero.

However, experience and available information on such sources indicates that the fast current controllers employed and the limited overcurrent capability of the converters result in fault current contributions generally not exceeding 200% of the rated current, without aperiodic or time-decaying components. Hence, a departure from the IEC Standard might be more appropriate for Type IV units, applying the following relation for their fault current contribution (instead of Eq. (23)):

$$\underline{I}''_k = kI_{rG} = ct \text{ over interval } \Delta t, \tag{24}$$

where $k = 1.5$–2.0 and Δt is the duration of the contribution (100 ms may be adopted here as well). If a transformer is used for the interconnection, the current is converted to the MV level using the rated (or highest) transformation ratio.

The constant current representation of Eq. (24) departs from the equivalent impedance principle of IEC 60909. One particular issue is the phase angle of this current, if a vector summation of individual contributions is adopted. It is proposed that the contribution of Type IV DG sources is simply added algebraically to the total fault level of all other sources, which will provide a result slightly on the safe-side.

4. Application results and discussion

The application of the fault level calculation methodology is demonstrated on the fictitious 20 kV distribution network of Fig. 4, selected so as to include all four DG Types. The network is fed by a 150/21 kV, 50 MVA transformer. Its maximum load is 35 MVA, at 0.85 lagging p.f. Three wind farms and one small hydroelectric plant are connected to the substation busbars via direct MV lines. A current limiting reactor is installed at the output of Wind Farm 3. The total capacity of all DG stations is 17.16 MW. Data for the network and the DG units are given in Table 1.

The calculation procedure is straightforward. Results for a three-phase fault at the MV busbars of the substation are shown in concise, tabulated format in Table 2. No motor load contribution is considered. The fault level contribution of the upstream grid is 238.65 MVA, whereas the DG stations provide 61.31 MVA in total. As expected, the contribution of Type IV DG units is much lower than all other Types (about 3 times less).

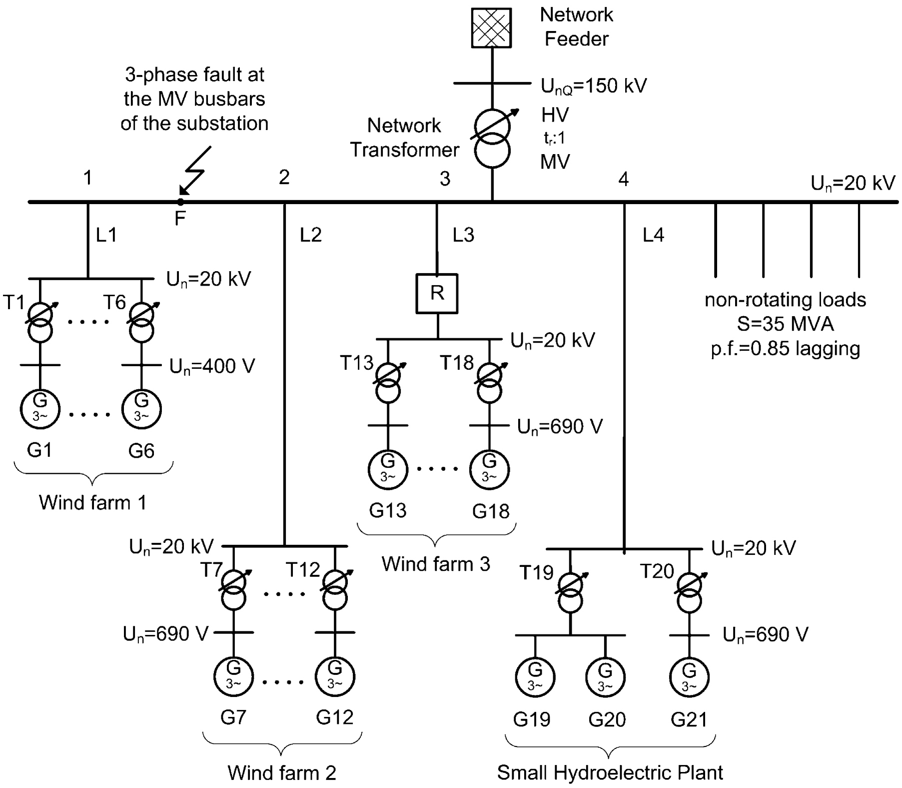

Fig. 4. Study case MV distribution network.

Table 1
Parameter values for the study case network of Fig. 4

Network feeder	$U_{nQ} = 150\,kV$, $S''_{kQ} = 3000\,MVA$, $R_Q/Z_Q = 0.1$
System transformer	$S_{rT} = 50\,MVA$, $u_{kr} = 20.5\%$ ($u_{k-} = 19.5\%$, $u_{k+} = 22\%$), $P_{krT} = 160\,kW$, $t_r = 150\begin{pmatrix}+12.5\%\\-17.5\%\end{pmatrix}/21\,kV$
Wind farm 1	$6 \times 600\,kW$ (G1–G6)
Generator (G1–G6)	Synchronous with converter (Type IV): $P_{rG} = 600\,kW$, $U_{rG} = 400\,V$, $I_{rG} = 866\,A$, $k = 1.5$
Unit transformer (T1–T6)	$S_{rT} = 630\,kVA$, $t_{rT} = 20(\pm5\%)/0.4\,kV$, $u_{krT} = 4\%$, $u_{RrT} = 1.2\%$
Line L1	Overhead line: $R_L = 0.215\,\Omega/km$, $X_L = 0.334\,\Omega/km$, $l_1 = 10\,km$ Underground cable: $R_L = 0.162\,\Omega/km$, $X_L = 0.115\,\Omega/km$, $l_1 = 0.5\,km$
Wind farm 2	$6 \times 660\,kW$ (G7–G12)
Generator (G7–G12)	DFIG (Type III): $P_{rG} = 660\,kW$, $U_{rG} = 690\,V$, $I_{rG} = 560\,A$
Unit transformer (T7–T12)	$S_{rT} = 700\,kVA$, $t_{rT} = 20(\pm5\%)/0.69\,kV$, $u_{krT} = 5\%$, $u_{RrT} = 1.2\%$
Line L2	Overhead line: $R_L = 0.215\,\Omega/km$, $X_L = 0.334\,\Omega/km$, $l_2 = 10\,km$ Underground cable: $R_L = 0.162\,\Omega/km$, $X_L = 0.115\,\Omega/km$, $l_2 = 0.5\,km$
Wind farm 3	$6 \times 850\,kW$ (G13–G18)
Generator (G13–G18)	Asynchronous (Type II): $P_{rG} = 850\,kW$, $U_{rG} = 690\,V$, $I_{rG} = 710\,A$, $I_{LR} = 5.5\,kA$, $R_G/X_G = 0.1$
Unit transformer (T13–T18)	$S_{rT} = 1000\,kVA$, $t_{rT} = 20(\pm5\%)/0.69\,kV$, $u_{krT} = 6\%$, $u_{RrT} = 1.1\%$
Reactor	$S_{rR} = 6\,MVA$, $U_{rR} = 20\,kV$, $u_{kr} = 14\%$, $u_{Rr} = 0\%$
Line L3	Overhead line: $R_L = 0.215\,\Omega/km$, $X_L = 0.334\,\Omega/km$, $l_3 = 10\,km$ Underground cable: $R_L = 0.162\,\Omega/km$, $X_L = 0.115\,\Omega/km$, $l_3 = 1\,km$
SHEP	$3 \times 1500\,kW$ (G19–G21)
Generator (G19–G21)	Synchronous (Type I): $S_{rG} = 1650\,kVA$, $U_{rG} = 690\,V$, $x''_d = 0.18\,p.u.$, $R_G/X''_d = 0.15$, $\cos\varphi_{rG} = 0.9$(lag) (operating p.f.=0.95 lag. to 0.95 lead.)
Unit transformer (T19, T20)	T19: $S_{rT} = 3.5\,MVA$, $t_{rT} = 20(\pm5\%)/0.69\,kV$, $u_{krT} = 8\%$, $u_{RrT} = 1\%$ T20: $S_{rT} = 2\,MVA$, $t_{rT} = 20(\pm5\%)/0.69\,kV$, $u_{krT} = 6\%$, $u_{RrT} = 1\%$
Line L4	Overhead line: $R_L = 0.215\,\Omega/km$, $X_L = 0.334\,\Omega/km$, $l_4 = 7.5\,km$

Table 2
Fault level calculation procedure and results for the network of Fig. 4

Contribution of upstream grid	
Network feeder	$(10) \Rightarrow Z_Q = 8.25\,\Omega$ $\underline{Z}_{Qt} = \underline{Z}_Q/t_r^2 = 0.016 + j0.161\,(\Omega)$
System transformer	$(11) \Rightarrow Z_T = 1.81\,\Omega,\quad (12) \Rightarrow R_T = 0.028\,\Omega$ $(13) \Rightarrow X_T = 1.808\,\Omega,\quad (17) \Rightarrow K_T = 0.930556$ $\underline{Z}_T = 0.026 + j1.682\,(\Omega)$
Contribution of the grid	$(22) \Rightarrow I''_k = 6.889\,\mathrm{kA}\quad (S''_k = 238.65\,\mathrm{MVA},\ \varphi_k = 88.684^\circ)$
Contribution of wind farm 1 (Type IV)	
Single generator	$(24) \Rightarrow I''_{ki} = 1.5\,I_{rG} = 1.299\,\mathrm{kA}$
Wind farm contribution	$(24) \Rightarrow I''_k = 6 \cdot (I''_{ki}/t_r) = 0.156\,\mathrm{kA}\quad (S''_k = 5.4\,\mathrm{MVA},\ \varphi_k = 90^\circ)$
Contribution of wind farm 2 (Type III)	
Single generator	$(16) \Rightarrow Z_G = 0.089\,\Omega$ $\underline{Z}_{Gt} = \underline{Z}_G \cdot t_r^2 = 7.434 + j74.338\,(\Omega)$
Unit transformer	$(11) \Rightarrow Z_T = 28.57\,\Omega,\quad (12) \Rightarrow R_T = 6.857\,\Omega$ $(13) \Rightarrow X_T = 27.736\,\Omega,\quad (17) \Rightarrow K_T = 1.015428$ $\underline{Z}_T = 6.963 + j28.164\,(\Omega)$
Line L2	$\underline{Z}_L = \sum_i R_i \cdot l_i + \sum_i X_i \cdot l_i$ $\underline{Z}_{L2} = 2.231 + j3.398\,(\Omega)$
Wind farm contribution	$(23) \Rightarrow I''_k = \frac{cU_n}{\sqrt{3}(\underline{Z}_{Gt}/6 + \underline{Z}_T/6 + \underline{Z}_{L2})} \Rightarrow I''_k = 0.605\,\mathrm{kA}\quad (S''_k = 20.95\,\mathrm{MVA},\ \varphi_k = 77.261^\circ)$
Contribution of wind farm 3 (Type II):	
Single generator	$(16) \Rightarrow Z_G = 0.072\,\Omega$ $\underline{Z}_{Gt} = \underline{Z}_G \cdot t_r^2 = 6.055 + j60.552\,(\Omega)$
Unit transformer	$(11) \Rightarrow Z_T = 24\,\Omega,\quad (12) \Rightarrow R_T = 4.4\,\Omega$ $(13) \Rightarrow X_T = 23.593\,\Omega,\quad (17) \Rightarrow K_T = 1.009282$ $\underline{Z}_T = 4.441 + j23.812\,(\Omega)$
Reactor	$(11) \Rightarrow Z_R = X_R = 9.333\,\Omega$
Line L3	$\underline{Z}_L = \sum_i R_i \cdot l_i + \sum_i X_i \cdot l_i$ $\underline{Z}_{L3} = 2.312 + j3.455\,(\Omega)$
Wind farm contribution	$(23) \Rightarrow I''_k = \frac{cU_n}{\sqrt{3}(\underline{Z}_{Gt}/6 + \underline{Z}_T/6 + \underline{Z}_R + \underline{Z}_{L3})} \Rightarrow I''_k = 0.468\,\mathrm{kA}$ $(S''_k = 16.2\,\mathrm{MVA},\ \varphi_k = 81.398^\circ)$
Contribution of SHEP (Type I)	
Single generator	$R_G = (R_G/X''_d) \cdot x''_d \cdot (U_{rG}^2/S_{rG}) = 0.008\,\Omega$ $(14) \Rightarrow \underline{Z}_G = 0.008 + 0.052\,(\Omega)$
Unit transformer	$(11)–(13) \Rightarrow \underline{Z}_{T19(HV)} = 1.143 + j9.071\,(\Omega)$ $(11)–(13) \Rightarrow \underline{Z}_{T20(HV)} = 2 + j11.832\,(\Omega)$
Correction factors	$(17) \Rightarrow K_{T19} = 0.997496$ $(19) \Rightarrow K_G = 1.041465(\sin\varphi = 0.312)$ $(21) \Rightarrow K_{SO} = 1.041465\,(p_G,\ p_T = 0, \sin\varphi = 0.312)$
(G19//G20 + T19)	$\underline{Z}_I = \frac{K_G \underline{Z}_G}{2} \cdot t_r^2 + K_{T19}\underline{Z}_{T19} = 4.548 + j31.771\,(\Omega)$
(G21 + T21)	$\underline{Z}_{II} = K_{SO}(\underline{Z}_G \cdot t_r^2 + \underline{Z}_{T20}) = 8.9 + j57.769\,(\Omega)$
Line L4	$\underline{Z}_{L4} = 1.613 + j2.505\,(\Omega)$
SHEP contribution	$(27) \Rightarrow I''_k = \frac{cU_n}{\sqrt{3}(\underline{Z}_1//\underline{Z}_2 + \underline{Z}_{L4})} \Rightarrow I''_k = 0.541\,\mathrm{kA}\quad (S''_k = 18.75\,\mathrm{MVA},\ \varphi_k = 78.629^\circ)$
Resulting fault level at the MV busbars	
$S''_k = 299.96\,\mathrm{MVA}$	Algebraic sum
$S''_k = 299.28\,\mathrm{MVA}$	Phasor sum with contribution of WF1 added algebraically

Wind Farm 3 (Type II source) also benefits from the 14% reactor at its output, reducing its contribution from 24.47 to 16.2 MVA.

The resulting total fault level is calculated at the end of Table 2 from the individual contributions, applying either algebraic or vector summation (in both cases, the fault current of the Type IV units in Wind Farm 1 is simply added to the result). The total fault level obtained is approximately 300 MVA, regardless of the summation method employed.

The design maximum fault level in the study case MV network is 250 MVA, a value related to the characteristics of the HV/MV transformer ($u_{kr} = 20\%$ at $S_{rT} = 50$ MVA base power). Since the calculated contribution of the upstream system is 238.65 MVA, the permissible fault level contribution of all DG sources connected to this network is just over 10 MVA. Such a small margin is indeed prohibitive for the interconnection of even moderate DG capacities.

Since the upstream grid constitutes the dominant short-circuit current source, the factors affecting its contribution are further investigated. Applying standard circuit theory, the short-circuit current provided by the upstream system for a three-phase fault at the substation MV busbars is given by:

$$I''_{kQ} = \frac{E_Q/t}{Z_Q/t^2 + Z_T(t)} = \frac{tE_Q}{Z_Q + t^2 Z_T(t)}, \tag{25}$$

where E_Q and Z_Q are the internal voltage and impedance of the HV system Thevenin equivalent and t the actual transformation ratio of the HV/MV transformer, which depends on the position of the OLTC, located at the primary (HV) winding of the transformer.

The transformer short-circuit impedance $Z_T(t)$ always varies with the tap changer position, particularly for HV/MV transformers with a wide regulation range. At lowest taps, corresponding to reduced HV system voltages, the active part (i.e. number of turns) of the primary winding is reduced, resulting in low Z_T values. The opposite holds for high tap positions. For the HV/MV transformer of the study case network, the OLTC regulation range is +12.5% to −17.5%, in steps of 1.25% (tap positions 1–25, rated position the 11th). The measured short-circuit impedance of the transformer at the lowest, rated and highest tap positions (25, 11 and 1) is 19.5, 20.5 and 22%, respectively.

Following a qualitative reasoning approach, in most practical situations $(Z_Q/t^2) \ll Z_T$ in Eq. (25) and hence the fault current is mainly determined by the transformer impedance $Z_T(t)$. In addition, if the voltage drop on the transformer impedance is ignored, the ratio E_Q/t becomes equal to the secondary voltage U^b prior to the fault, determined by the settings of the OLTC controller (voltage regulator). Hence, Eq. (25) becomes:

$$I''_{kQ} \approx \frac{E_Q/t}{Z_T(t)} \approx \frac{U^b}{Z_T(t)}. \tag{26}$$

Based on the simplified relation Eq. (26), the highest fault levels will occur for operation at low HV or high MV side voltages:

- Operating at increased secondary voltages U^b, as is always the case in rural networks with long overhead lines, results in higher fault currents. To this effect contribute both the increased numerator in Eq. (26), as well as the reduced denominator, since higher U^b corresponds to a lower t and hence Z_T value.
- Operation at a reduced HV system voltage results also in higher fault currents, since the tap position will be lower and therefore the Z_T values decreased.

Given the primary (HV) and secondary (MV) voltages and the power through the transformer, it is easy to calculate the actual tap position, taking into account the voltage drop on the internal impedance, which varies with the tap position. This has been performed for the study case HV/MV transformer and the results are plotted in Fig. 5 against the transformer active power (positive when supplied to the MV network), with the power factor as a parameter. The two diagrams correspond to opposite combinations of HV and MV side voltages (high/low and low/high). The HV system short-circuit capacity is constant at 3000 MVA, whereas a linear variation of the transformer impedance with

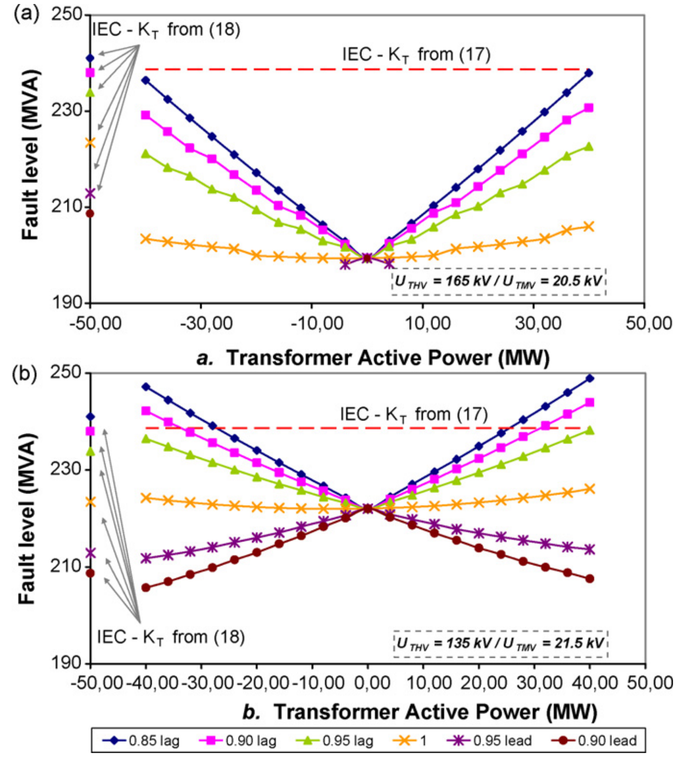

Fig. 5. Variation of the fault level contribution of the upstream grid with the transformer active power, for different p.f. values and operating voltages at the HV and MV side.

the transformation ratio has been assumed. It is noted that in the diagram of Fig. 5a, curves for leading p.f. are missing because the OLTC upper regulation limit (+12.5%) is exceeded for the given terminal voltage constraints.

On the diagrams of Fig. 5, the fault level as per IEC 60909 is also shown, calculated using Eq. (22). If the correction factor K_T in Eq. (22) is found from Eq. (17), then the horizontal dashed line is obtained, i.e. the fault level contribution is independent of the operating conditions. When K_T is calculated using Eq. (18), with $I^b/I_r = 0.8$, the resulting fault level depends on the transformer p.f. ($\sin \phi_T^b$ in Eq. (18)), but not on its power. The values obtained in this case (one per p.f. value) are marked on the y-axis of each diagram.

Comparing the two diagrams of Fig. 5 it is confirmed that increased fault currents are expected at reduced HV or increased MV side voltages. Under such conditions and for inductive p.f. values, the IEC 60909 calculation may even underestimate the maximum fault level, although in general it provides a safe-side estimation. On the other hand, when the transformer operates lightly loaded or at capacitive p.f. values, the fault level is significantly reduced. In this case, more accurate results are obtained by the IEC calculation using Eq. (18) for the K_T factor, since Eq. (17) provides too high an estimation. The direction of the active power flow has a small impact on the resulting fault level, as expected, due to the low resistive part of the transformer and HV system impedances.

An important observation from Fig. 5, potentially useful in the management of the fault level, is that operating the substation near unity p.f. (or slightly capacitive), a reduction of the prospective fault currents is possible. In the example of this section, this reduction is of the order of 20 MVA, i.e. roughly equal to the fault level contribution of an additional 5 MW DG station.

5. Solutions for fault level reduction

The issue of fault level management (reduction) is not new and practicing power engineers are familiar with its implications. In the context of DG, however, it has received relatively little attention in the literature, although it is an important barrier for achieving large penetrations in MV networks. Mitigating solutions to the problem, grouped in four major categories, are outlined in the following.

5.1. Increase the design maximum fault level

This is not a realistic option in public distribution networks, where equipment and constructions are largely standardized by the utilities, since a global upgrade would be required for the switchgear in the network, as well as in customer/user installations.

5.2. Reduce the prospective short-circuit current of the grid

The dominant short-circuit current contribution is that of the upstream grid, via the step-down transformers. Reducing this contribution implies one of the following:

- Reconfiguration of the network: This might be considered in meshed networks with multiple in-feed points. In radial networks, typical in public distribution, this is practically realizable only in HV/MV substations with transformers operating in parallel, by opening the MV bus-couplers. However, this could possibly decrease the fault level too drastically (e.g. by up to 50%, if two identical transformers operate in parallel), potentially creating voltage regulation and power quality problems, tap-changer premature wear and regulation adequacy issues, as well as operation-related disadvantages (e.g. need for proper sharing of the load among the transformers).
- Increase the short-circuit impedance of the transformers: The fault current contribution of the grid at the substation busbars is roughly inversely proportional to the transformer short-circuit impedance, Z_T. A reasonable increase of Z_T (i.e. of u_{kr} in Eq. (11)) may indeed provide a crucial margin for the connection of additional DG, without the aforementioned undesired consequences. This is a realistic approach, worth considering for new HV/MV transformers in areas where a high DG penetration is expected. Alternatively, reactors may be connected in series to the transformer, achieving the same result. A check of the resulting fault level reduction and its implications will be required.

5.3. Reduce the prospective short-circuit current of the DG

This can be realized in three alternative ways:

- Select equipment with increased short-circuit impedance: This means step-up (LV/MV) transformers with a higher short-circuit voltage, synchronous generators with a higher subtransient reactance and so on. The feasibility of such an approach is constrained by technical and market availability issues, including the increased cost of custom designed equipment. In addition, operating considerations may also arise, most important being the voltage regulation within the DG station and possibly its transient stability (usually not a critical factor at the distribution level). This approach could be considered on a case specific basis, but cannot constitute a general remedy to the fault level issue.
- Installation of current limiting reactors: This is a common measure, consisting in the installation of a reactor in series with the DG station, effectively increasing its total short-circuit impedance. The associated costs are reasonable, the reliability is good, the losses are low and the maintenance requirements are not an issue. Nevertheless, the voltage regulation needs a careful check, whereas the achieved reduction of the fault contribution is only moderate for reasonable reactor impedance values.
- Connection via power electronics converters: Type IV DG sources contribute maximum faults currents slightly higher than their rated current. Hence, from the fault level point of view, they are superior to all other types, which provide much higher contributions (4–5 times the rated current). However, this is not really a user- or utility-implementable measure, as the choice of DG equipment technology is constrained by a variety of factors (state-of-the-art, technical feasibility and market availability, cost, etc.). It should also be mentioned that increased short-circuit current contributions are not always a drawback, as they may assist the operation of overcurrent protection devices.

5.4. Active limitation of the short-circuit current

Active short-circuit current limitation can be achieved by devices such as Is-limiters, super-conducting and solid-state current limiters [3]. These devices are connected in series to the circuit and present negligible impedance when the current remains below a threshold, not affecting normal operation. When a current surge is sensed, they increase their apparent impedance or break the circuit well before the first cycle peak, effectively limiting the peak current value.

Super-conducting and solid-state fault current limiters are still at the research and prototyping stage and are therefore not suitable for integration in the network. Currently, only the Is-limiter is commercially available as a standardized industrial product, suitable for the voltage and power range of interest. Although such devices have been used in mostly industrial networks in certain countries, their use is not common in public distribution networks.

6. Conclusions

The short-circuit capacity of existing distribution networks is often close to their design level, leaving little margin for the interconnection of DG resources. The significance of this technical constraint renders necessary the application of established fault current calculation methodologies, such as the IEC 60909 standard applied in this paper. The main objective of the work presented is to provide guidance in the application of the IEC 60909 for DG fault level studies, extending its provisions to DG power sources, not covered in the Standard. It should be noted that, in the case of WTs, their behavior during faults is affected by technologies and solutions dictated by the low voltage ride-through requirements, which were recently introduced in the grid codes of several countries and still lack uniformity and standardization.

Due to the practical significance of the fault level constraints and the uncertainty of the maximum fault current contribution of Type III and IV DG sources, establishing a standardized short-circuit test for such units would definitely contribute to the more objective evaluation of their interconnection requirements. In addition, the authors believe that the relevant standards of IEC and IEEE for short-circuit current calculations need to be revised to include the effect of DG resources and standardize their treatment.

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