DEVELOPMENT AND CROSS-VALIDATION OF SHORT-CIRCUIT CALCULATION METHODS FOR DISTRIBUTION GRIDS WITH HIGH PENETRATION OF INVERTER-INTERFACED DISTRIBUTED GENERATION

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ABSTRACT

Validated approaches for reliably integrating inverter interfaced distributed generation in steady state short circuit calculation methods are lacking. The estimation of minimal short circuit currents at relay or fuse locations mandatory for protection system design and parameterization studies is problematic. Two enabling steady state methods have been developed for cross validation. Quantitative comparisons show only small deviations in the studies cases. Based on the findings during development further research is recommended. Assumptions to be validated by simulation and experiments have been identified.

INTRODUCTION

A growing number of decentralized generators (DG) are installed in electrical distribution systems worldwide. DG have become relevant for transmission system stability. Consequently, recent grid codes define requirements on their behaviour in normal operation and in case of grid faults. Those may be conveniently fulfilled by inverter interfaced DG (IIDG). Figure 1 shows the share of IIDG in a distribution system operator's (DSO) area.

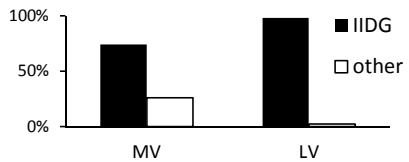

Figure 1: Share of IIDG (count) per voltage level in a distribution system with >180,000 DG

In distribution systems with high local DG penetration rates those need to be considered during dimensioning of primary and parameterization of secondary equipment. Traditional short-circuit calculation methods (SCCM) are available to DSO, but have been developed considering directly coupled rotating machinery only [1]. DSO are in need for SCCM considering IIDG reliably.
Recent draft standards offer recommendations for considering IIDG [2]. Their adequacy for worst-case estimation of the largest fault current in e.g. breaker dimensioning is evident. Protection parameterization studies also require the calculation of minimal fault currents at the relay locations (e.g. CT 1-3 in Figure 5) in order to guarantee relay pickup and tripping.

Considering IIDG properly in SCCM is challenging as they behave as controlled current sources in case of voltage sags. This completely different behaviour to rotating generators yields significantly altered current distributions in the distribution system during a fault. Several steady state SCCM reflecting the current source behaviour of IIDG have been proposed [3–5]. These need to be of iterative nature [6]. Three different problem formulation, modelling and solution approaches have been observed in a review:

- **Type A**: superposition of current source approach [3]
- **Type B**: load flow based approach [4]
- **Type C**: variable impedance approach [5]

Their suitability for high IIDG penetration scenarios is unknown. Also, the problem formulation and solution method might be of influence to the results obtained. As reliable SCCM considering IIDG are needed for practical usage, suitability and dependability of the calculation approaches should be verified.

In this paper a contribution to dependable SCCM with IIDG is made. As a first step, methods of type A and B have been implemented and are tested in different scenarios. A cross validation is performed to identify the systematic influence of the calculation method type.

PROBLEM STATEMENT AND SOLUTION

IIDG will alter the fault currents sensed by protective relays. Those may trigger instantaneously for high fault currents but will typically be delayed (>100 ms) for the lowest expected fault currents. For the latter, the highest potential for IIDG influence on protection behaviour is likely to occur. Therefore, an approach for calculating the IIDG current injection in case of minimum grid fault current cases is sought. As protection studies are performed in the planning stage with limited information available, a steady state calculation approach is favoured. A steady state calculation approach does not intrinsically permit consideration of IIDG behaviour over time. Though, when capable of estimating the fault currents sensed by the relay at the end of their trip delay (e.g. 100 ms), the following cases may be identified:

- relay triggered dynamically, but falls back or relay neither triggered dynamically nor at the end of delay
- relay triggered with valid trigger conditions at the end of delay

In the following potentially influential IIDG and their fault current contribution are classified. The applicability of the steady state approach is then discussed. Finally, the general and specific methodology is shown.

Classification of IIDG influence potential

Basically, two general possibilities of IIDG behaviour in short circuit situations are possible in medium (MV) and high (HV) voltage grids:

- immediate disconnection
- remaining at grid according to national and international guidelines for the capability of Low Voltage Ride Through (LVRT) (e.g. [7])

Influence on short circuit currents and residual voltages only exist in the second case and here only in the event of further current infeed (see Figure 2).

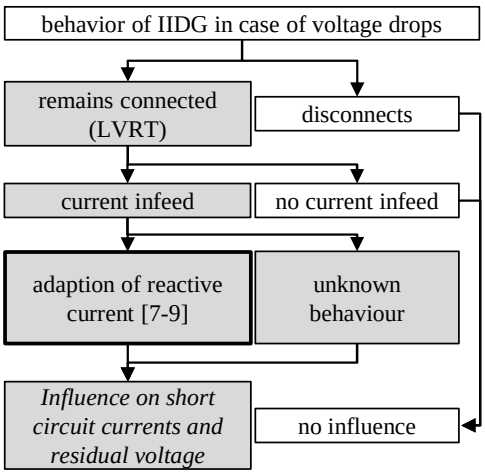

Figure 2: IIDG behaviour in short circuit case and influence on measurements at position of CT

Existing IIDG may behave in an unknown way. For new IIDG the DSO will require a behaviour according to technical guidelines [7] and national legislation [8]. Those require a specific current in context of a dynamic grid support. In what follows behaviour according to these criteria is assumed. Such an approach is a worst case scenario for the influence of IIDG on short circuit currents and residual voltages.

Fault current contribution of IIDG

IIDG performing dynamic grid support need to continue feeding their pre-fault current and a prioritized additional reactive current [7–9]. For the latter, two different characteristics for the steady state injection exist (see Figure 3).

IIDG manufacturers need to interpret and detail the requirements of the directives. Degrees of freedom exist for current reference generation during grid faults that influence the steady state current contribution:

- choice of pre-fault current and voltage references
- residual voltage measurement
  - one-time initial or
  - continuously updated during fault
- injection capabilities for unsymmetrical voltage sags
  - positive sequence currents only
  - negative + positive sequence current
- overcurrent ratings
- current limitation and prioritisation strategies

Those aspects need to be considered in reference SCCM before deriving less detailed worst-case SCCM.

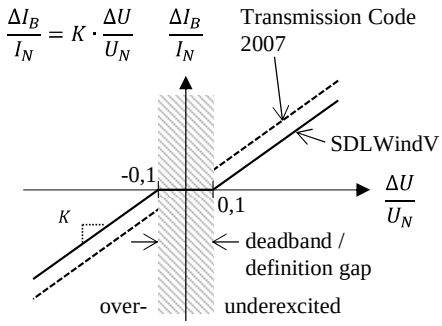

Figure 3: Required additional steady state IIDG reactive current injection for positive sequence voltage drops

Usability and validity of a steady state approach

The steady state of IIDG reactive current injection is required to be reached in Germany within 60 ms [8]. For fault locations in distribution systems, the AC component of the fault current typically does not decay significantly. All interactions between grid and IIDG are assumed to take place within this time span. The paper focus on the calculation of the steady state IIDG fault current contribution within the time span of 60 ms after fault entry and before any IIDG may disconnect (>150 ms) [7–9]. The validity of the assumptions taken are under investigation at the moment by comparison to time domain simulations and laboratory tests [10].

Any changes over time (e.g. protection reactions, fault current contributions alterations, IIDG disconnection, etc.) have to be treated as exogenous factors. An outer framework (to be developed) may consider these aspects using the following methods as its calculation kernel.

General methodology

The general iterative methodology used in both developed methods is shown in Figure 4. The fault current injection references of the IIDG are updated in an outer loop based on the previously calculated nodal voltages (amplitude and phase angle). Starting point for the iteration is a fault calculation without IIDG current injection. The iterations do not correspond to time steps but rather steps in solving a nonlinear system of equations valid within the discussed time span.

In order to determine the influence of the solution approach to the steady states found, two methods of type

A and B have been developed independently.

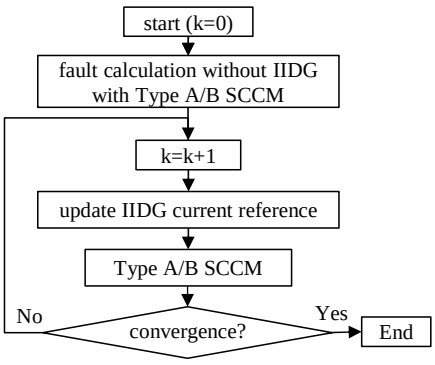

Figure 4: Simplified general methodology for considering IIDG in SCCM of type A and B

Type A Method

The Type A method is based on the superposition method. The known pre-fault state is superposed by the change state due to a fault [11–14]. The change state is found by solving the system of equations consisting of

- the nodal admittance matrix (NAM) equation and
- voltage and current conditions at the fault points.

A formulation systematically incorporating any type of fault in the NAM is used [13]. The used formulation in the phase frame offers generality [11].
Without IIDG the problem to solve is a system of linear equations. Due to the nodal voltage dependent current injections of IIDG a NAM equation with voltage independent and dependent elements results.

$$Y\,\Delta U = I_{const} + C_{IIDG}(\Delta U) \qquad (1)$$

The IIDG characteristic $I_{IIDG} = C_{IIDG}(\Delta U)$ may be linear, piecewise linear (discontinuities, saturations) or generally nonlinear. An iterative approach may be used [3]. The problem to solve is iteratively adapted based on the nodal voltage solution of the previous iteration (k-1).

$$Y\,\Delta U_k = I_{const} + C_{IIDG}(\Delta U_{k-1}) \qquad (2)$$

A solution of the linear problem is found per iteration. Instead of nested loops for IIDG's nodal current injection amplitude and phase [3] a single loop is used to avoid over-specialization due to assumptions.
An introduced damping technique repeatedly estimates the final nodal voltage solution per IIDG based on previous iteration steps.

Type B Method

In principal it is possible to calculate a short circuit situation like an unsymmetrical load flow (ULF) by regarding specific constraints [4]. A special node type is introduced. It uses active and reactive currents instead of powers. In this method derivatives $(\frac{\partial i}{\partial v}, \frac{\partial i}{\partial \phi})$ are used to find an iterative solution of the steady state in a Newton-Raphson-Algorithm [15]. Therefore, certain start specifications are used:

- start voltage (nominal voltage or pre-fault state)
- required active and reactive currents
- required fault type and location
- slack bus

The result is a steady state result. The advantage in comparison to standardised SCCM is the simple implementation of non-linear functionalities and the implicit calculation of angle position.
The described behaviour of IIDG is taken into account by using an outer iterative loop (Figure 4). In a first calculation a solution is detected by neglecting the IIDG. In following steps the IIDG currents are adjusted according to the specified behaviour until convergence is reached.

TEST CASES

The comparison of method A and B results is performed on the basis of the grid in Figure 5.

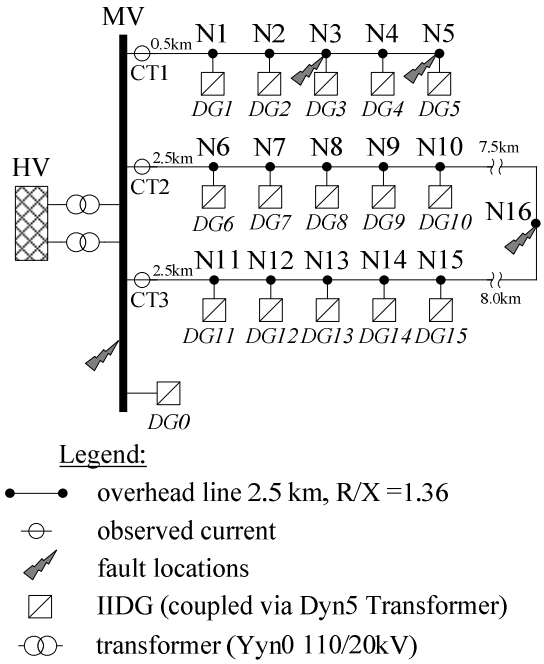

Figure 5: Test Case Grid with possible IIDG locations

The neutral point treatment is varied. IIDG locations are varied according to Table 1. They are mainly connected at the beginning of the feeders due to voltage restrictions.

Table 1: IIDG Penetration Scenarios

Scenario Name	Nr. IIDG	Locations of IIDG	Rated power MVA
None	0	-	-
Single	1	N2	2
Low	4	MV, N2, N4, N10	2
High	16	all in Figure 5	2 / 50 (DG0)

IIDG of unmodelled feeders are represented by an aggregate DG0 connected to the MV bus bar. The IIDG fault behaviour is specified as follows:

- positive sequence only current injection
- pre-fault power 1 p.u., power factor 1
- current overrating 1.1 p.u.
- grid support according to SDLWindV [8], K = 2
- voltage measurement and current reference generation continuously updated during fault

RESULTS

Convergence

The iterative solution is defined to be convergent when all changes (amplitude/angle) of observed quantities simultaneously remain within a threshold. Global convergence is reached when all nodal voltages, current injections (IIDG, faults) and line currents are convergent.
Cases that typically do not converge globally are zero impedance three phase faults at IIDG locations or at radial feeder nodes with downstream IIDG. These cases electrically ideally decouple IIDG and separate the grid. Careful considerations may enable usage of partial results like relay currents (CT1-3) for downstream faults.
The introduced Type A method damping technique successfully eliminates all cases of non-convergence for asymmetrical faults with IIDG parameterization as given above. In some cases global convergence is not reached when applying a control law with discontinuities (e.g. Transmission Code 2007).

Comparison of grid faults without IIDG

The comparison of Type A and B results for the fault currents sensed at CT 1-3 in all IIDG penetration scenarios and IIDG parameters described above yields relative errors smaller than 0.0001 p.u. These errors are assessed as sufficiently small for further comparison in case of IIDG fault contributions.

Comparison of Three Phase Faults with IIDG

The Type A and B method have been compared in case of three phase faults. Table 2 shows the relative difference of the methods' results for the currents in CT 1-3 in case of a three-phase fault at N5 and N16.

Table 2: Relative deviation of CT current amplitudes from Type A to B method in IIDG scenario "High"

fault point	relative deviation [p.u.]		
	CT 1	CT 2	CT 3
N5	-0,019		
N16		-0,004	-0,005

The maximum observed relative deviation of the two methods' results for the current in CT 1-3 is 0.02 p.u. in the penetration scenario "High". Therefore, the focus lies on this scenario in the following. As grid parameters as well as IIDG sizing and control have been ensured to be identical in detail among the two methods, the determined IIDG's current injections need to be responsible for the deviations. Figure 6 shows the relative deviation of injected amplitudes.

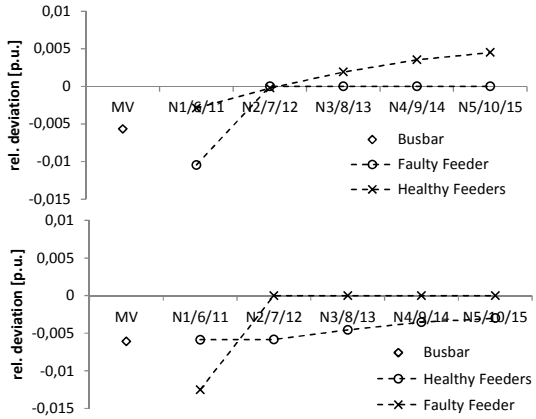

Figure 6: Relative IIDG amplitude deviations from Type A to B method for a fault at N5 (upper) and N16 (lower)

IIDG close to the fault experience voltage sags that lead to current limitation and therefore identical current amplitudes in both methods. Still, the phase angle of injection may be influenced by the depth of sag due to its influence on the required ΔI_B. Furthermore, the control strategy will be influential, but is kept identical here.
IIDG further away from the fault (e.g. beginning of faulty feeders, busbar, non-faulted feeders) experience less deep sags and do not enter current limitation. The IIDG injection amplitude and phase angle are then influenced by the depth of sag.
As the deviation of current injection amplitudes between the methods is not sufficiently explanatory for the deviations of the current amplitudes at CT 1-3, a significant influence is ascribed to the injection phase angles.
The two methods are observed to calculate voltages at the IIDG connection points of relative amplitude deviations within 0.04 p.u. Voltage amplitudes at the IIDG connection points and IIDG current injections non-trivially interact grid-wide (see also [16]).
A sensitivity analysis performed in [16] reveals a significant influence of control design choices on the relay currents (CT 1-3). The relative deviations from the cross-validated results are shown in Figure 7.

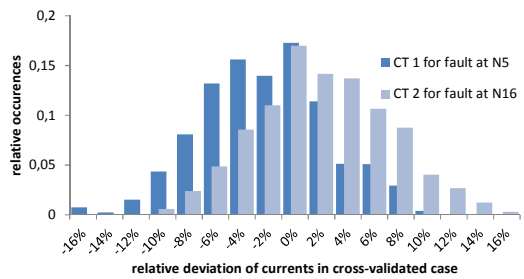

Figure 7: Relative deviation of the faulty feeders' CT currents due to variation of and diversity of IIDG control parameters for Type A method [16]

Further work is required to fully identify the reasons of the two methods' results deviation for identical parameterization. As the deviations introduced by the different implemented methods (0.02 p.u.) are small in comparison to the IIDG control influence (0.16 p.u.), priority of further work lies on the systematic consideration of the IIDG control variety and diversity in a real distribution system. Especially for asymmetrical faults the degrees of freedom for designing the IIDG control increase. For practical purposes of a DSO most of the discussed detailed control law aspects will typically be unknowns.

CONCLUSION

Two steady-state short-circuit calculation methods enabling in detail IIDG consideration have been successfully developed. Necessary assumptions for calculating the minimal fault currents with IIDG have been extensively discussed. Both methods necessarily fail to converge for zero impedance three phase faults that electrically decouple IIDG from the rest of the grid.

The two methods yield results for faults in grids without IIDG that lie within 0.0001 p.u. of each other. Results for identically implemented IIDG behaviour in case of three phase faults show relative deviations of the obtained solutions within 0.02 p.u. for a high IIDG penetration scenario. As shown in [16] IIDG fault behaviour is influenced by design choices. These may lead to deviations of the relay currents (CT 1-3) within 0.16 p.u. of the current amplitudes calculated in the cross-validation of the methods. Systematically considering these unknowns for practical purpose calculations is assessed as the prior task for future work. Furthermore, cross-validation of the methods for asymmetrical fault cases needs to be performed.

As an overall conclusion an overdue contribution to the development of steady-state short-circuit calculation methods for minimal fault currents under IIDG penetration has been made. Simplified calculation approaches suitable for practical purposes need to be developed using these as calculation kernels.

Acknowledgments

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