Influence of reactive current settings of converters on distance protection

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Abstract—In the present paper, the influence of reactive current settings of converters on traditional distance protection schemes is investigated. Contemporary grid codes demand converter-based generation to inject additional reactive current during faults to support the grid voltage. Through steady state simulations, it is illustrated that the amount of reactive current, defined by a fixed gain factor, impacts the calculated fault impedance by distance protection. It is illustrated that with a fixed gain factor for reactive current contribution, correct operation of traditional distance protection schemes to protect lines connected to converter-based generation is not feasible.

Index Terms—distance protection, grid codes, reactive current requirements, sequence components, power system protection

I. INTRODUCTION

Distance protection is extensively used in transmission and distribution grids around the world. When a fault occurs in the grid, the distance protection estimates the location of the fault by calculating the fault impedance based on voltage and current measurements. This method to identify and isolate faults has worked reliable in the past.

With climate change as the main incentive, renewable energy technologies are increasingly being installed in the power system. Most of these renewable sources, such as wind turbines or solar farms, employ power electronic converters to connect to the grid. When a fault occurs in the grid, these converters will exhibit a fault behavior that is different from synchronous generation. Distance protection, which has been designed to operate in a grid powered by synchronous generation only, may fail.

Recent studies have demonstrated the vulnerability of distance protection in grids dominated by converter-based generation. In [1], commercial distance protection relays were tested hardware-in-the-loop where up to half of the simulated faults resulted in a malfunctioning of the distance protection. Especially phase-to-phase faults led to high failure rates. A similar study was performed in [2] where the authors investigated the performance of two commercial distance protection relays in a simulation grid with a high penetration of PV. By conducting hardware-in-the-loop tests, it is shown that especially ungrounded LL- and LLL-faults cause relay failures. For grounded LG- and LLG-faults, it is shown that even for a correct fault detection, the relays react slower than with conventional generation due to the filter delays in the PV-inverter controls.

In [3], simulations were performed where distance protection was used to protect a line supplied by a multi-modular converter. The authors concluded that distance protection should not be used for lines supplied by converter-based sources. Other research draws similar conclusions and uncovers the vulnerability of distance protection in converter-dominated grids [4]–[6].

From the state of research, it is clear that distance protection is highly affected by the presence of power electronic converters in the grid. However, little attention has been paid to the impact of different grid code requirements. Grid codes often require additional reactive current injection during a fault to support the grid voltage. The amount of reactive current is defined by a gain factor as a function of the voltage deviation. The present work investigates how this gain factor influences the fault impedance estimation of distance relays. This work focusses on

II. INFLUENCING PARAMETERS ON DISTANCE PROTECTION

The main parameters influencing a correct fault impedance estimation are the fault behavior of the converter and the settings of the distance protection. The fault behavior of the converter is flexible and primarily depends on the control system design that is implemented in the converter. The control system, in turn, must comply with the requirements stated in the grid codes. Accept for the hardware constraints of the converter, the fault behavior is thus largely dictated by the relevant grid code. The following subsections will guide the reader through these influencing parameters.

A. Converter's fault behavior

Converter-based generation has a fault behavior entirely different from synchronous generation. Due to the flexibility of the control system, the fault behavior is more a design parameter rather than a physical response to network disturbances [7] [8]. There are, however, some physical constraints that limit the flexibility of converters.

The semi-conductor switches within the converter have stringent thermal limitations. Consequently, the converter can only provide overcurrent up to 1.1 pu [9]. Only if the converter is deliberately oversized, it can withstand higher currents.

Fig. 1: Reactive current injection requirement [11]

B. Grid codes

Grid codes impose requirements on generation units in order to keep the power system stable and reliable. When a fault occurs in the network, the voltage will drop. To help stabilize the network and counteract the voltage drop, grid codes often impose reactive fault current contribution requirements [10].

In contemporary grid codes, this requirement is often specified for only positive sequence values. Although mostly not specifically stated, converters often suppress all negative sequence current contribution, even for asymmetrical faults [5]. As a consequence, the converter injects only positive sequence currents and suppresses any negative sequence current injection. The amount of required reactive current is defined by a gain factor in function of the voltage drop caused by the fault. Figure 1 illustrates the meaning of the gain factor 'k'.

Suppressing all negative sequence current has some drawbacks. Injecting balanced currents into an asymmetrical fault can cause over-voltage in the healthy phases. This, in turn, reduces the short-circuit power of the converter and mitigates the positive effects of providing reactive current support [10]. To deal with these drawbacks, the most recent grid codes specify reactive current contribution in both positive and negative sequence. This approach has only recently been introduced in grid codes such as the German mid-voltage and high-voltage codes [12] [13]. Also the Spanish grid code is evolving toward specific negative sequence requirements for converter-based generation [14]. The amount of required reactive current in both sequences is also defined by a gain factor 'k' as illustrated in figure 1. Only now, 'k' is separated into a positive sequence gain factor k_1 and a negative sequence gain factor k_2 .

Because of the significant drawbacks of injecting balanced currents, and the recent developments toward specific negative sequence requirements, the remainder of this work will focus on converters that inject both sequence currents.

Apart from the requirements regarding the amount of reactive current, also a rise time and settling time of the fault response from the converter is defined in some grid codes. However, the objective of this work is to investigate the steady state fault response and its impact on distance protection.

C. Conventional distance protection

The conventional way of determining the distance to a fault is by calculating the impedance seen by the relay based on voltage and current measurements. Since the impedance is generally homogeneous over the length of the line, the impedance to the fault is proportional with the distance to the fault. By comparing the impedance to the fault with predefined zones of protection on the RX-plane, the relay decides whether the fault should be isolated.

The impedance seen by the relay is likely to exhibit a certain error. The amplitude and angle of the local and remote current in-feed, and the fault resistance, will cause the calculated impedance to shift away from the true fault impedance. This is illustrated in the conceptual RX-diagram in figure 2 where $\bar{I}_R$ and $\bar{I}_L$ stand for the remote-end and local current in-feed respectively [15].

Fig. 2: Influence of remote current infeed and fault resistance on the fault impedance 'seen' by the relay

If there is synchronous generation at both ends of the protected line, the local and remote current in-feed will have similar phase angles. Only if there is a significant load-transfer over the line, the phase angles of the local and remote in-feed fault current can differ [15]. This no longer holds true for converter-based generation where the fault response entirely depends on the converter's control system. Consequently, the factor $\bar{I}_R/\bar{I}_L$ can be almost any value. From a distance protection point of view, it is imperative that $\bar{I}_R/\bar{I}_L$ has no imaginary part so that the impedance seen by the relay is shifted only along the resistive axis (for quadrilateral protection characteristics). This way, no under-reach or over-reach occurs due to a shift of the impedance along the reactive axis.

III. SIMULATION FRAMEWORK

In this section, the fault scenario and the simulation model used in the simulations are elaborated.

A. Grid topology and Simulation scenarios

Consider the grid topology presented in figure 3 where a converter-based generator is connected to the main grid.

This converter-based generator can for example be a type-4 full-scale wind turbine, a solar park or battery storage. In today's wind turbines, the type-3 doubly fed induction generator (DFIG) is also widely used. However, due to its unique structure, the fault behavior of DFIGs is different from full-scale converters and needs separate attention. The influence of DFIGs on conventional distance protection is not covert in this paper.

The converter and the grid in figure 3 supply a load of 8 MVA connected at busbar B2. Line 12 and 23 have an arbitrary length of 20 km. At the beginning of line 12, a distance protection relay protects the line against faults and provides backup protection for the adjacent line 23.

In the simulations, two different scenarios are investigated. In the first scenario, presented in figure 3(a), a phase-to-phase fault between phase B and C is considered at four different locations along line 12 and 23: at 5 km (F_1), at 15 km (F_2), at 25 km (F_3) and at 35 km (F_4). For each fault location, the simulation is performed several times with different values of the gain factor 'k'. In the second scenario presented in figure 3(b), a phase-to-phase fault between phase B and C is considered on line 23 at 25 km from distance protection P_1 . The simulation is performed with a fixed gain factor of $k=2$ but for different power and current ratings of the converter.

In all the simulations, a phase-to-phase fault is chosen because it is the one most likely to cause distance protection to malfunction [1], [2].

Fig. 3: Grid topologies and fault scenarios: (a) faults at different locations, (b) faults at different converter's current and power ratings

For the distance relay P_1 , quadrilateral protection zones are selected. The zone reach settings are determined based on [15]. The primary zone reaches up to 80% of line 12. The second zone reaches up to halfway the adjacent line 23, and the third zone reaches to the end of the adjacent line. The resistive reach settings are calculated as if the converter would be a conventional synchronous generator with a comparable nominal power rating. This way, the effect that converter-based generation has on conventional distance protection can

be illustrated. Based on the minimum short-circuit current, a presumed line spacing of 0.7 meter and a security margin of 50 %, the R-zone reach is set to 10.5Ω, 13Ω and 14.8Ω respectively.

B. Converter control system

For the simulations, a steady state model of the grid topology in figure 3 is developed which builds further on the models presented in [8].

This steady state model calculates the network voltages and currents using kirchoff's laws. Since the output voltages and currents of a converter depend on its control system, an iterative approach is used to calculate the steady state behavior of the converter. The flowchart in figure 4 illustrates the working principle of this calculation method which is build out of three main blocks. In the convergence block, the steady state currents and voltages are calculated iteratively until the results reach convergence. Different grid code requirements or reactive current injection strategies can be implemented in this block. After the convergence block, the calculated results move into the current limiter. For the simulations in this paper, a current limit of 1.2 pu is adopted. After the current limiter, a voltage limiter ensures that the converter does not cause over-voltage beyond 1.25 pu. More details on how this model is developed can be found in [8].

Fig. 4: Flow chart of the converter's control system

IV. SIMULATION RESULTS

With the model presented in the previous section, the fault scenarios from figure 3 are simulated.

Fig. 5: Fault impedance estimation for increasing values of k : fault at 5 km (a), 15km (b), 25 km (c) and 35 km (d). The black colored marker indicates the simulation where $k_1=k_2=2$.

A. Fault scenario one: different fault locations

In this first fault scenario, a phase-to-phase fault is applied on different locations as illustrated in figure 3(a). For every fault location, the simulation is performed several times using different values of the gain factor ' k '. Starting with no reactive current injection ($k=0$) the gain is increased up to a value of three in steps of 0.2. The resulting RX-diagrams are presented in figure 5. A gain factor of two is sometimes suggested in grid codes as the default value, such as in [16]. This gain factor is therefore highlighted in figure 5 by a black colored circular marker.

From figure 5, several observations can be made. First, it is clear that the value of the gain factor defines the impedance

seen by the distance relay. For increasing values of k , the impedance shifts upwards in reactive direction. That is because a higher value of ' k ' means that the converter injects more additional reactive current to counteract the voltage deviation. As a consequence, the distance relay calculates a different fault impedance, even though the fault's location and resistance have not changed.

Second, as the fault is applied further on line 12 and 23, the calculated fault impedance shifts away from the true fault impedance. This can best be explained based on figure 2. For remote faults, e.g. fault four in figure 3(a), more fault current will flow from the remote end than for close-by faults (e.g. fault 1 is figure 3(a)). This affects the factor $R_f \cdot \bar{I}_R / \bar{I}_L$,

causing the calculated impedance to shift away from the true fault impedance. For the fault at 35 km presented in figure 5(d), the impedances are shifted out of the protection zones.

Last, the plots of figure 5 exhibit a shift along the reactive axis. For example, a gain factor of two for a fault at 15 km would result in a correct distance estimation by the relay (black colored circular dot in figure 5(b)). The same value for a fault at 5 km would cause the relay to under-reach whereas a fault at 25 km would result in an over-reach. There is no general value of 'k' that would fit for all faults in figure 5.

B. Fault scenario two: different converter's current and power ratings

In this second scenario, a phase-to-phase fault is applied on line 23 at 25 km from the distance protection. The reactive current gain factor 'k' is set at a fixed value of two.

This fault is simulated four times while changing the power rating from 2 MVA to 4 MVA and the current rating of the converter from 1 pu to 1.5 pu. The resulting fault impedance estimations are shown in figure 6. Tabel I links the markers A to D to the different power and current ratings of the converter.

Fig. 6: R-X diagram for different current and power rating

TABLE I: Corresponding power and current ratings of the converter: figure 6

	$I_{lim} = 1pu$	$I_{lim} = 1.5pu$
$S_{nom} = 2MVA$	D	B
$S_{nom} = 4MVA$	C	A

From figure 6, it is clear that different power and current ratings of the converter can result in over-reach (A), correct zone of protection (B, C) and under-reach (D). However, it must be emphasised that even with an impedance estimation

in the correct protection zone (B and C in figure 6) commercial distance protection relays might still fail. The impedance calculation is only one of the criteria that commercial distance protection relays use to identify and isolate a fault [2]. Other criteria, such as faulted phase selection, might still fail due to the low current contribution of converters.

V. DISCUSSION

From the two simulation scenarios presented in the previous section, the following observation can be made.

The simulations illustrate that it is not possible to set the gain factor 'k' as such that it will yield distance protection to operate correctly. Parameters such as the distance to the fault and the current and power rating of the converter have a significant impact on the impedance estimation by the relay. There is no one-fit-for-all gain factor that works for all scenarios. This conclusion can be explained intuitively.

Distance protection will make a correct estimation if the calculated fault impedance only exhibits a (small) shift along the resistive axis. For that, the factor $R_f \cdot \overline{I_R} / \overline{I_L}$ in figure 2 must not have an imaginary part. That can only be true if the remote and local current in-feed have the same phase angle. In a conventional setup, both the remote and local end will have synchronous generation. When a fault happens on the line, both sides will have a very similar fault current response. The current phase angles of the remote and local end will thus not differ significantly and the distance relay makes a correct estimation. When the local end has a converter-based generation, the response to the fault is governed by the control system. When using a fixed gain factor, the fault behavior of the local end will not reflect the behavior of the remote end at all times. The current phase angles at both ends will be different, causing the distance protection to malfunction. Therefore, within the framework of contemporary grid codes, who demand reactive current by a fixed gain factor, using traditional distance protection schemes on lines fed by converter-based generation is not feasible.

VI. CONCLUSION

Contemporary grid codes demand converters to inject additional reactive current during faults to provide dynamic voltage support. The required amount of additional reactive current is defined in function of the voltage deviation by a fixed gain factor.

In the present paper, the steady state fault response of converters for different values of the gain factor, and its impact on distance protection, has been investigated. By simulating two different fault scenarios, it is shown that the choice of the gain factor influences the calculated fault impedance by the distance relay. Furthermore, it is illustrated that, even for a fixed gain factor, the calculated fault impedance is influenced by other parameters such as the location of the fault and the current and power rating of the converter. It is thus not possible to set a fixed gain factor so that the distance relay will estimate the fault impedance correctly under different circumstances.

Conclusively, protecting lines supplied by converter-based generation with traditional distance protection schemes seems not possible with the current injection strategies defined in contemporary grid codes.

Future work includes repeating the simulations for type-3 doubly fed induction generators, developing new distance protection algorithms to protect lines fed by converter-based generation and optimising the converter controls from a protection point of view.

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