Impact of Inverter-Based Resources on Protection Schemes Based on Negative Sequence Components

Technical Brief — *Bulk Power System Integration of Variable Generation*

1 INTRODUCTION

With recent advancements and continuously decreasing costs of wind turbine generator (WTG) and photovoltaic (PV) cell technologies, the share of renewable energy sources in the generation fleet of power grids increases worldwide, along with the individual size of the WTGs, wind parks (WPs) and solar plants. Solar plants, as well as Type IV WTGs (also referred to as full-size converter (FSC)) and Type III WTGs (also referred to as doubly-fed induction generator (DFIG)) are connected to electrical grids through power electronic converters, thus in this document are referred to as inverter-based resources (IBR). Figure 1-1, Figure 1-2, and Figure 1-3 illustrate the schematics of a PV, FSC WTG, and DFIG WTG, respectively. In case of FSC WTGs and PV solar plants, the ac-dc-ac converter system is sized based on the total power output of the generation. The converter system is a fully scaled interface between the grid and the rest of the renewable resource. In case of DFIG WTGs, the converter system's size is a fraction of the total generation capacity (around 30%). In this topology, the stator of the induction generator is directly connected to the grid. The rotor side is connected to the grid through an ac-dc-ac converter.

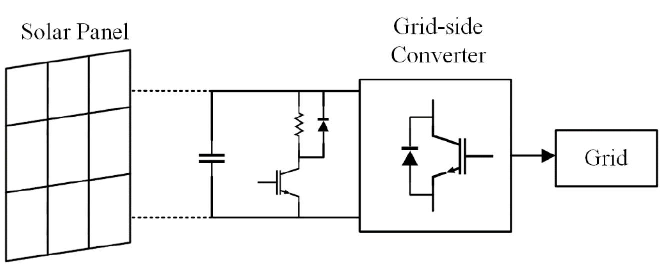

Figure 1-1: *PV*

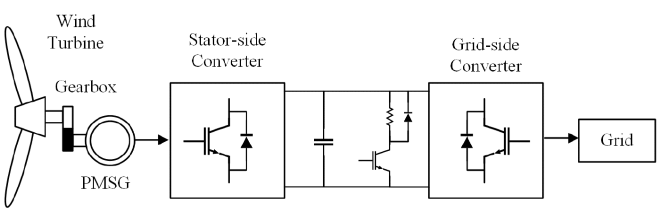

Figure 1-2: *FSC WTG.*

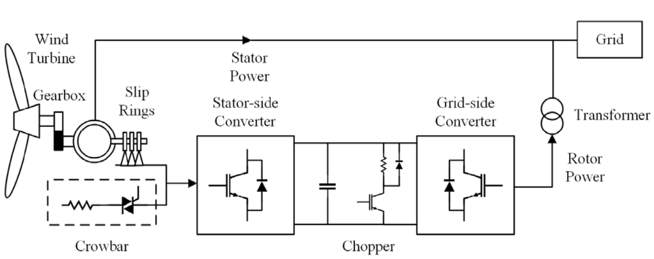

Figure 1-3: *DFIG WTG*

With the increasing share of IBRs, the dynamic and transient behavior of power systems change considerably, due to fundamental differences in the physical equipment between IBRs and conventional synchronous generators (SGs). IBRs have different fault current signatures compared to conventional SGs. The fault response of SGs is driven by laws of physics while for IBRs it depends, to a large extent, on the control schemes of the converters. The typical IBR fault response characteristics are as follows:

- ***Fault current magnitude:*** The magnitude of the sustained fault current contributed by a wind/solar plant is typically low, since it is constrained by the converter limiter to values close to nominal load current.
- ***Fault current duration:*** The IBR fault current typically has an initial transient response (first 1/2 cycle to 1.5 cycles) during which it can exceed the nominal values, and after that it is limited to values close to nominal current as explained before. During this short time period, which is considered to be the converter controls "reaction time", the fault current response is uncontrolled. The amount of time which an inverter can continue to inject current into the grid during a fault, depends on the inverter control design and thermal limits of the power electronics. For DFIG WTG, the initial transient response is quite different than the initial response of FSC WTG, and the fault current can reach up to several times of the nominal current depending on the electrical parameters of the induction machine.
- ***Fault current power factor/phase angle:*** The inverter fault current may be either resistive, inductive or capacitive, and the power factor/phase angle depends on the inverter reactive power/voltage control mode. The control mode significantly impacts the angular relationship between on-fault voltages and currents near the wind/solar plant which some protection functions (e.g., directional elements) require for correct operation.

- ***Fault sequence quantities:*** The inverter fault current does not include zero sequence component and the negative sequence current is typically partially or fully suppressed depending on the inverter control [1].

Given those fault response characteristics, there is an anticipated impact of IBRs on various legacy protection schemes [2],[3].

The focus of this paper is to analyze and demonstrate the potential impact of IBRs on protection schemes relying on negative sequence voltages (V2) and currents (I2). There are a number of protection elements that are based on I2 detection and the angular relationship between V2 and I2. These elements are traditionally designed considering the significant amount of I2 circulating during unbalanced faults partly due to the low negative sequence impedance path provided by SGs. IBRs, on the other hand, have different negative sequence fault response characteristics compared to conventional generators, as it will be described in detail in Section 4.

This paper first identifies the key differences between non-symmetrical fault responses of a SG and an IBR. Next, the paper discusses how these differences may adversely impact the performance of protection elements that consume negative sequence quantities. Finally, examples of misoperation are provided to illustrate these effects and identify the causes. The objective is to highlight the challenges of negative sequence based protection elements in the presence of IBRs and the need for protection solutions to address these challenges to ensure dependable and secure protection in the presence of IBRs. The remainder of the paper is organized as follows. Section 2 provides an overview of the response of a SG to non-symmetrical faults on the power system. Section 3 gives an overview of negative sequence element based protection elements. Section 4 studies the effect of non-symmetrical faults on IBRs as compared with those of a SG. Finally, Section 5 shows how these differences impact negative sequence protection elements. Section 6 provides a summary of main findings.

1.1 List of Abbreviations:

BES	Bulk Electrical System
CSC	Coupled Sequence Control
DSC	Decoupled Sequence Control
DCB	Directional Comparison Blocking
DCUB	Directional Comparison Unblocking
DFIG	Doubly Fed Induction Generator
EMT	Electromagnetic Transients
FID	Fault Identification
FSC	Full-size Converter
GSC	Grid Side Converter
IBR	Inverter-based Resource
MSC	Machine Side Converter
POI	Point of Interconnection
POTT	Permissive Overreaching Transfer Trip
PUTT	Permissive Underreaching Transfer Trip
SG	Synchronous Generator
WTG	Wind Turbine Generator

2 FAULT BEHAVIOR OF SYNCHRONOUS GENERATORS

A SG does not generate V2 or I2. However, the low negative sequence impedance of a SG provides a path for I2 to flow. Therefore, a non-symmetrical power system fault will cause negative sequence current to flow through a SG, the magnitude of which will be largely governed by the negative sequence impedance of the power system.

For fault analysis and fault current calculations, a SG is represented by its negative sequence impedance in the negative sequence network of the system. The resistance part of the machine's negative sequence impedance is much smaller than the reactance part. The negative sequence reactance is usually approximated by the average of direct and quadrature axis subtransient reactances when its data are not available [4]. Typically, the negative sequence impedance of a SG is comparable to its positive sequence impedance.

To illustrate an example I2 fault current flow through a SG, an unbalanced fault has been simulated in the test system of Figure 8-1. The negative-sequence impedance of the simulated SG is 0.18 per-unit (pu). Figure 2-1(a) is a plot in the time domain of the magnitude of the negative-sequence voltage (V2) and current (I2) at bus G3. Figure 2-1(b) is a phasor representation of V2 and I2. As shown in Figure 2-1 (a), prior to the fault the V2 and I2 are zero since in the simulation the grid is considered balanced and operating normally. Following the inception of the fault, the magnitude of V2 increases to approximately 0.25 per-unit (pu). Due to the low negative-sequence impedance of G3, V2 causes a I2 of about 1.5 pu to circulate through the generator G3. Figure 2-1 (b) shows that for a phase-A-to-B fault, I2 leads V2 by 92°. This is due to the predominantly inductive nature of the negative-sequence impedance of the SG.

This angular relation as well as the amplitude of negative-sequence quantities are of particular importance for negative sequence based protection elements. Traditionally, these protection schemes have been designed assuming that negative sequence quantities are present in significant levels and have the above-mentioned angular relation during unbalanced fault conditions.

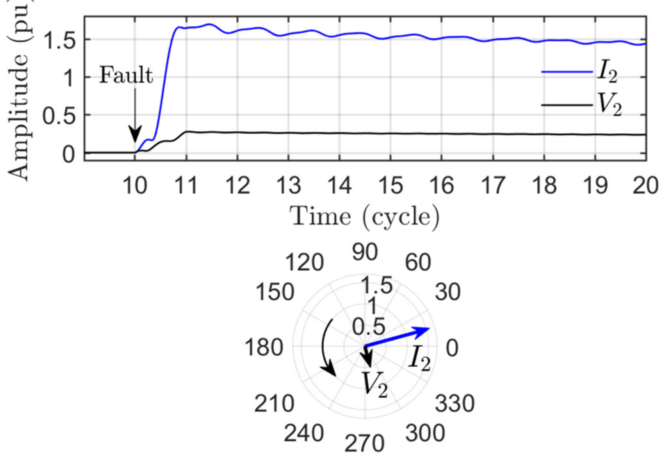

Figure 2-1: *Negative-sequence voltage and current – SG scenario.*

3 NEGATIVE-SEQUENCE BASED PROTECTION SCHEMES

Several protective relaying functions are based on negative sequence quantities which indicate unbalanced system operating conditions. Negative-sequence-based protection has some advantages over zero-sequence-based protection [5] and the calculation of negative-sequence quantities by digital relays is simple. Examples include Instantaneous Negative Sequence Overcurrent (50Q), Negative Sequence Time Overcurrent (51Q), Directional Negative Sequence Overcurrent (67Q), communication-assisted protection, and phase selection/fault identification (FID). Other protection schemes such as differential protection and quad ground distance element [6] also use negative-sequence quantities but are not described in detail in this paper.

3.1 Instantaneous Negative Sequence Overcurrent Element (50Q/51Q)

The 50Q/51Q elements operate when the magnitude of the negative-sequence current exceeds a set threshold. This threshold is commonly referred to as the pickup setting and specified by the protection engineer based on protection studies. These elements are used to detect unbalanced conditions in the power system and are commonly used in conjunction with other protection elements such as fault detectors, time overcurrent elements, and distance elements.

The successful operation of 50Q/51Q elements relies on the assumption of negative-sequence current being present in substantial levels during a non-symmetrical fault. When the source behind the 50Q/51Q element is a SG, the magnitude of the I2 is typically large enough to exceed the pickup setting of 50Q/51Q element, therefore these elements should assert. For example, under the same AB fault described in Section 2, an overcurrent relay located at bus 5 with 50Q/51Q elements operating on I2 with a pickup set to 0.5 pu [7] successfully detects the fault because the magnitude of I2 is 1.5 pu. (see Figure 5-1).

3.2 Directional Negative Sequence Overcurrent Element (67Q)

The 67Q element determines the direction of a fault (forward or reverse to the relay) by measuring the phase angle difference between the negative-sequence voltage and current phasors. Figure 3-1 shows a typical implementation and operating principle of the 67Q element. The concept is that a forward/reverse fault causes the voltage phasor to have a phase angle of about -90°/90° with respect to the current phasor. This assumption stems from the highly inductive nature of the negative-sequence network in a SG dominated grid. In general, assuming a characteristic angle of -90 degrees (a common setting), the 67Q element classifies a fault as forward if the measured phase angle of I2 lags the polarizing voltage (-V2) between 0 and 180 degrees. The 67Q element classifies a fault as reverse otherwise.

For example, under the same AB fault described in Section 2, a 67Q element on bus 5 looking towards bus 6 sees a phase angle difference of -92° between the polarizing negative-sequence voltage and current phasors and thus successfully classifies the fault as forward.

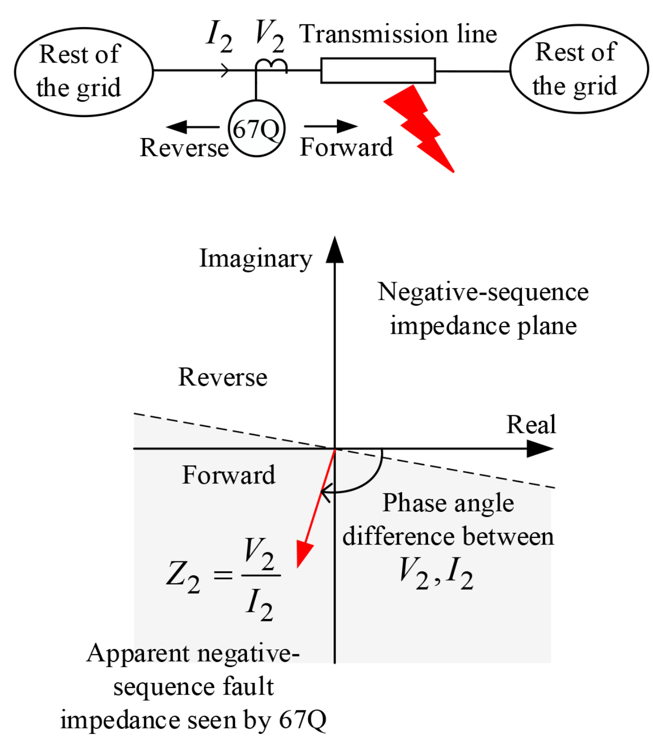

Figure 3-1: *Basic operation principle of 67Q*

3.3 Pilot Communication-Assisted Protection

Instantaneous distance elements only protect approximately 80% of the transmission line, the remaining 20% of the transmission line is protected by a delayed distance element. The result of this is that not all faults within the protected line would be cleared without any intentional delay. This is not generally acceptable for transmission lines on the bulk electrical system (BES). The aim of communication-assisted protection schemes is to provide tripping without any intentional delay for all line terminals of a protected transmission line for faults anywhere within the line. Additionally, communication aided tripping schemes are used to provide high speed tripping for high resistance faults within the line that are not detected by distance elements. Pilot communication assisted tripping schemes are basically broken up into two categories namely permissive schemes and blocking schemes [8], [9].

Permissive schemes are comprised of two types of schemes:

Permissive underreaching scheme (PUTT): in this scheme the underreaching distance element (zone 1) sends the permissive bit (TX) to the remote terminal. At the remote terminal, tripping is accelerated when the remote terminal's overreaching zone (zone 2) is asserted and the permissive signal from the local terminal is received (RX). The concept of the PUTT scheme is shown in Figure 3-2 (a))

Permissive overreaching scheme (POTT): in this scheme the overreaching distance element (zone 2) sends the permissive bit (TX) to the remote terminal. At the remote terminal tripping is accelerated when the remote terminal's overreaching zone (zone 2) is asserted and the permissive signal from the local terminal (RX) is received. The concept of the POTT scheme is shown in Figure 3-2 (b)

The most frequently used blocking scheme is the ***directional comparison blocking scheme (DCB)*** and it operates as follows. The overreaching zone (zone 2) starts a timer with a pickup delay set above the delay of the communication channel. The remote terminal sends a blocking signal to the local terminal if the remote detects a fault behind the remote terminal (i.e. in the reverse direction which could be zone 3). Should the remote terminal not detect a fault in the reverse direction no blocking signal is sent to the local terminal. Once the pickup delay at the local terminal expires and no blocking signal is received from the remote terminal, tripping at the local terminal is accelerated via the DCB scheme. The concept of a DCB scheme is shown in Figure 3-2 (c).

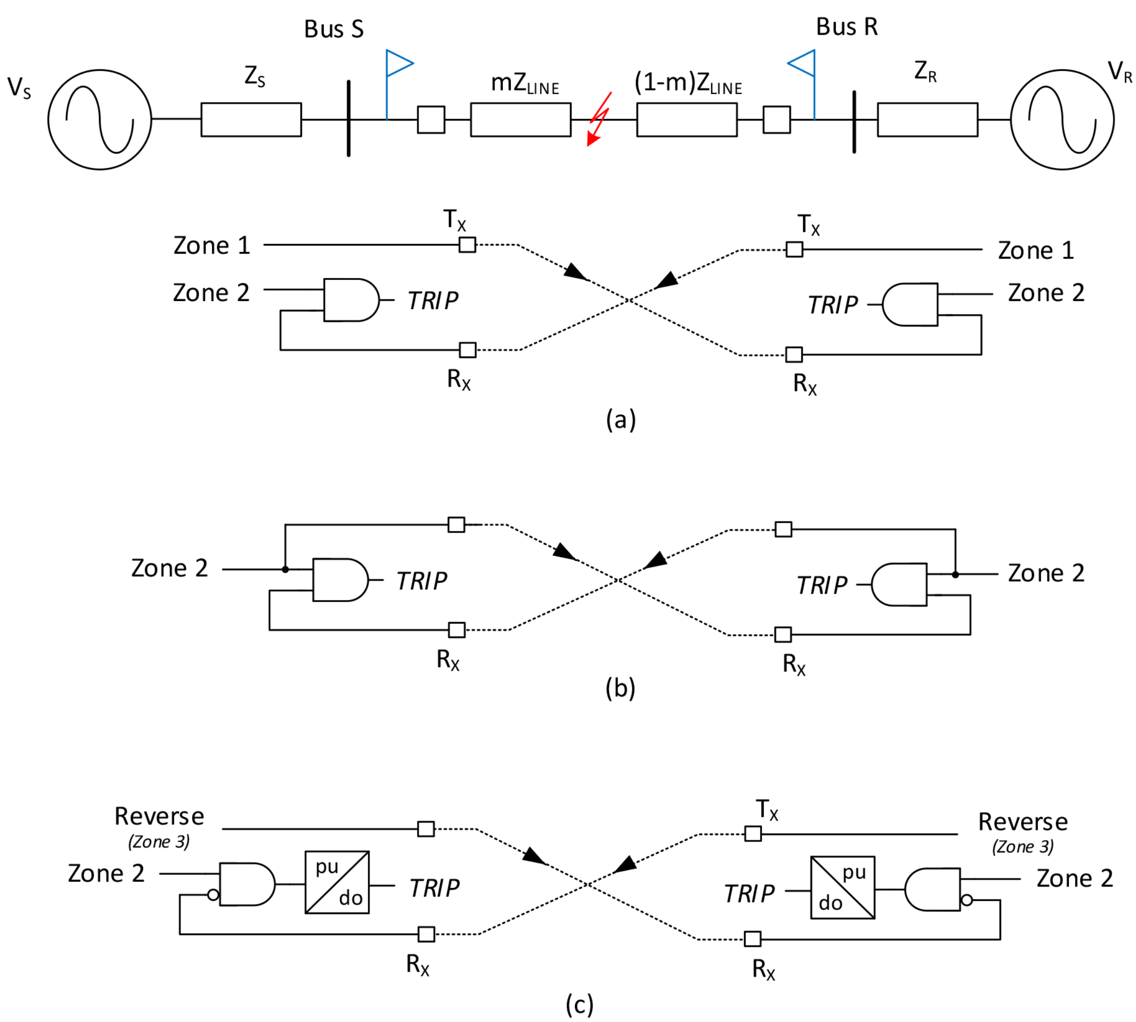

Figure 3-2: *Basic logic for PUTT, POTT and DCB schemes*

3.4 Fault Identification Logic (FID)

The FID scheme (or also known as phase selection) is used by protective elements to identify the type of a fault, i.e. single-phase-to-ground, or phase-to-phase, and the faulted phase(s) [10]. Such information is necessary in protection applications such as single-pole tripping where the faulted phases are identified and opened to allow the continuity of power transfer through healthy phase(s). In one implementation of the FID logic the phase angle relationship between the negative- and zero-sequence current is used to identify the faulted phase loop [10]. Figure 3-3 shows a graphical representation of the sectors of FID and the corresponding phase selection decision. These angle ranges correspond to a known theoretical relation between the phase angle of negative- and zero-sequence currents IA2 and IA0 under different fault types. The FID identifies the type of fault and faulted phases by determining which sector the measured phase angle falls within as follows:

- If the phase angle between IA2 and IA0 is 0°±margin (the yellow sector), the fault type is either AG or BCG, and the relay enables AG and BC elements only. In this sector, the relay selects AG or BCG based on which element has the lowest calculated reach;
- If IA2 lags IA0 by 120°±margin (the red sector), the fault type is either BG or CAG, and the relay enables BG and CA elements only. In this sector, the relay selects BG or CAG based on which element has the lowest calculated reach;
- If IA2 leads IA0 by 120° (±margin) (the green sector), the fault type is either CG or ABG, and the relay enables CG and AB elements only. In this sector, the relay selects CG or ABG based on which element has the lowest calculated reach.

The margin angle is a setting of FID, used to ensure proper phase selection under varying fault resistance.

Successful operation of FID relies on the validity of the presumed mathematical relation between the phase angles of negative- and zero-sequence quantities. In a SG dominated grid, this relation holds valid due to the inductive nature of the negative-sequence network and machine impedance.

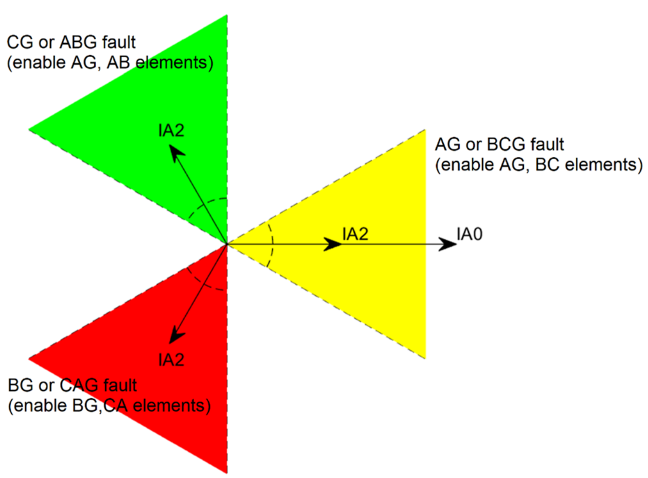

Figure 3-3: *Graphical representation of the sectors of FID and the corresponding phase selection decision.*

4 NEGATIVE SEQUENCE FAULT CURRENT CONTRIBUTION FROM INVERTER-BASED RESOURCES

Negative sequence fault current contribution from IBRs depends highly on the control of the converters. DFIG WTGs, similar to SGs, provide a low impedance path for the circulation of negative sequence current, while the apparent negative sequence impedance of FSC WTGs and solar plants can be very high depending on the design of converter controllers. On the other hand, unlike SGs, the converters of IBRs can be controlled to act like a source of negative sequence current, although its magnitude is likely limited because the phasor sum of positive (active and reactive) and negative sequence currents cannot exceed the current limit of the converter.

4.1 Negative Sequence Fault Current Contribution from IBR with Full-size Converters

The negative sequence component of the fault current at the terminals of FSCs under unbalanced fault conditions depends on the design of the grid side converter (GSC) control. It can be totally suppressed, or it can have a value depending on the control logic. This is in sharp contrast to SGs, where the negative sequence component corresponds to several times the rated current. The short circuit current contribution from an IBR is adjusted by converter controls which are stabilized within a few cycles after the fault initiation. During these first cycles, a certain amount of negative sequence component may be present in IBRs. This presence is because of the delay in the adjustment of reference current signals following the instantaneous change in voltage at the terminals of an IBR due to a short circuit on the network.

One typically used control scheme for IBR is the coupled sequence control (CSC) scheme [11]. With CSC, FSC is not expected to inject any negative sequence currents to the grid during unbalanced loading conditions or faults. In practice, it injects a very small amount due to the phase shift in low pass measuring filters.

Another control scheme is the decoupled sequence control (DSC) scheme [11]. Unlike its output currents, the GSC terminal voltages always contain negative sequence component during unbalanced loading conditions or faults, and this causes second harmonic oscillations in the GSC active power output as well as the dc bus capacitor voltage. These second harmonic oscillations can be eliminated by adopting a DSC scheme that allows for control of the positive and negative sequence converter currents independently. With DSC scheme, the negative sequence converter currents can be adjusted for eliminating the second harmonic oscillations. However, DSC typically gives the priority to the positive sequence reactive currents designated by the FRT requirement and use only the remaining available converter capacity to mitigate those oscillations. In summary, DSC scheme allows injection of negative sequence current during unbalanced faults but with the purpose of reducing above mentioned oscillations. Even then, the injected negative sequence current may not lead the negative sequence voltage by 90 degrees like in case with SGs.

Although a GSC operating under DSC injects considerable amount of negative sequence currents during unbalanced faults, another control logic has been proposed in the recent VDE-AR-N 4120 Technical Connection Rules [12]. It includes a negative sequence reactive current requirement to reduce the possibility of protection system misoperation. A GSC operating under this scheme injects a negative sequence reactive current as a function of the negative sequence voltage at the GSC terminal, as shown in Figure 4-1. This characteristic basically emulates a SG with 1/k pu negative-sequence reactance (k being the slope of the characteristics) with current rating limitation. The code also requires that the injected negative sequence current lead negative sequence voltage by 90 degrees emulating the behavior of a SG.

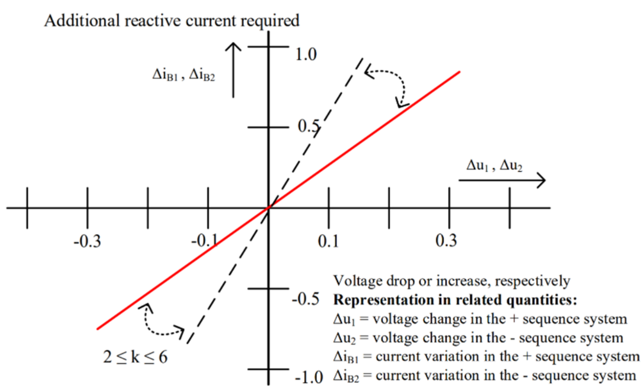

Figure 4-1: *Characteristic curve for negative-sequence current injection of IBRs based on VDE-AR-N 4120 Technical Connection Rules [12].*

4.2 Negative Sequence Fault Current Contribution from Doubly-Fed Induction Generators

The unbalanced fault current signature of DFIG WTGs naturally includes a negative sequence component when the DFIG converters are operating under traditional CSC. The induction generator rotor circuits provide a low impedance path to negative sequence currents under unbalanced conditions. Hence, the DFIG fault behavior from the point of negative sequence current component is similar to SGs.

The unbalanced steady state operation and fault conditions give rise to high frequency components in rotor currents and torque pulsations in DFIG WTGs. To mitigate the corresponding stress, different control methods have been proposed in which the objective is to reduce the oscillating air gap torque during periods of asymmetry. This is achieved by adopting a decoupled sequence control (DSC) scheme in DFIG converter controls. Rotor side converter (RSC) or GSC (or both of them) can be used for mitigating DFIG torque pulsations during unbalanced loading or fault conditions. The unbalanced fault current signature of DFIG changes significantly with the implemented mitigation method. When RSC is used for this purpose, the negative sequence current on the induction generator rotor circuits are determined by the DSC of RSC and this results into a significant decrease in negative sequence fault current contribution of DFIG WTG compared to the one with CSC scheme. However, when the GSC is used for compensating the negative sequence current required in the network (during any unbalanced operation), the negative sequence fault current contribution of DFIG WTG becomes even larger compared to the one with CSC scheme. Similar to FSCs, DSC of DFIG converters give the priority to the positive sequence reactive currents designated by the FRT requirement and use only the remaining available converter capacity mitigating torque pulsations. It should be mentioned that the VDE-AR-N 4120 Technical Connection Rules also applies for DFIG. The code specifies the minimum required amount of injected reactive negative-sequence current, and in the case of DFIG the amplitude of the negative-sequence current contribution may be more than this amount due to the machine contribution.

In summary, fault current contribution from IBRs is lower compared to SGs and the negative sequence component of their fault current is also different. In case of FSC topology, it is possible to suppress almost all of negative sequence current component. Control schemes that eliminate the negative sequence current component of DFIGs have also been proposed in the literature [13].

4.3 Example Simulation Results and Field Measurements for Negative Sequence Fault Current Contribution from IBRs

To highlight the difference between the negative-sequence fault current characteristics of IBRs and SGs, let us repeat the same AB fault described in Section 2, but now with IBRs instead of SGs. To that end, all the SGs in the simulation model of Figure 8-1 are replaced by IBRs. Simulations were performed using EMTP-RV software. Details on the models and their validation can be found in [14]-[20]. Figure 4-2 shows the negative-sequence voltage and current of G3 due to the fault when the generator is a DFIG WTG (left) or an FSC WTG (right). Comparison of Figure 2-1 and Figure 4-2 reveals two key differences between the negative-sequence fault current characteristics of IBRs and SG:

(i) The amplitude of the negative-sequence fault current is generally smaller under IBRs. In the simulation test, this amplitude was 0.75 pu under DFIG WTG and 0.12 pu under FSC WTG which is substantially smaller than 1.5 pu under SG. This implies that IBRs present a high "equivalent impedance" path to the negative sequence current. In these simulations, this "equivalent" negative sequence impedance is about 0.45 pu under DFIG WTG and 4.50 pu under FSC WTG which is substantially larger than 0.18 pu under SG;

(ii) The difference between the phase angle of negative-sequence voltage and current phasors is -101.6° under DFIG WTG and 131.4° under FSC WTG which is different from -92° under SG.

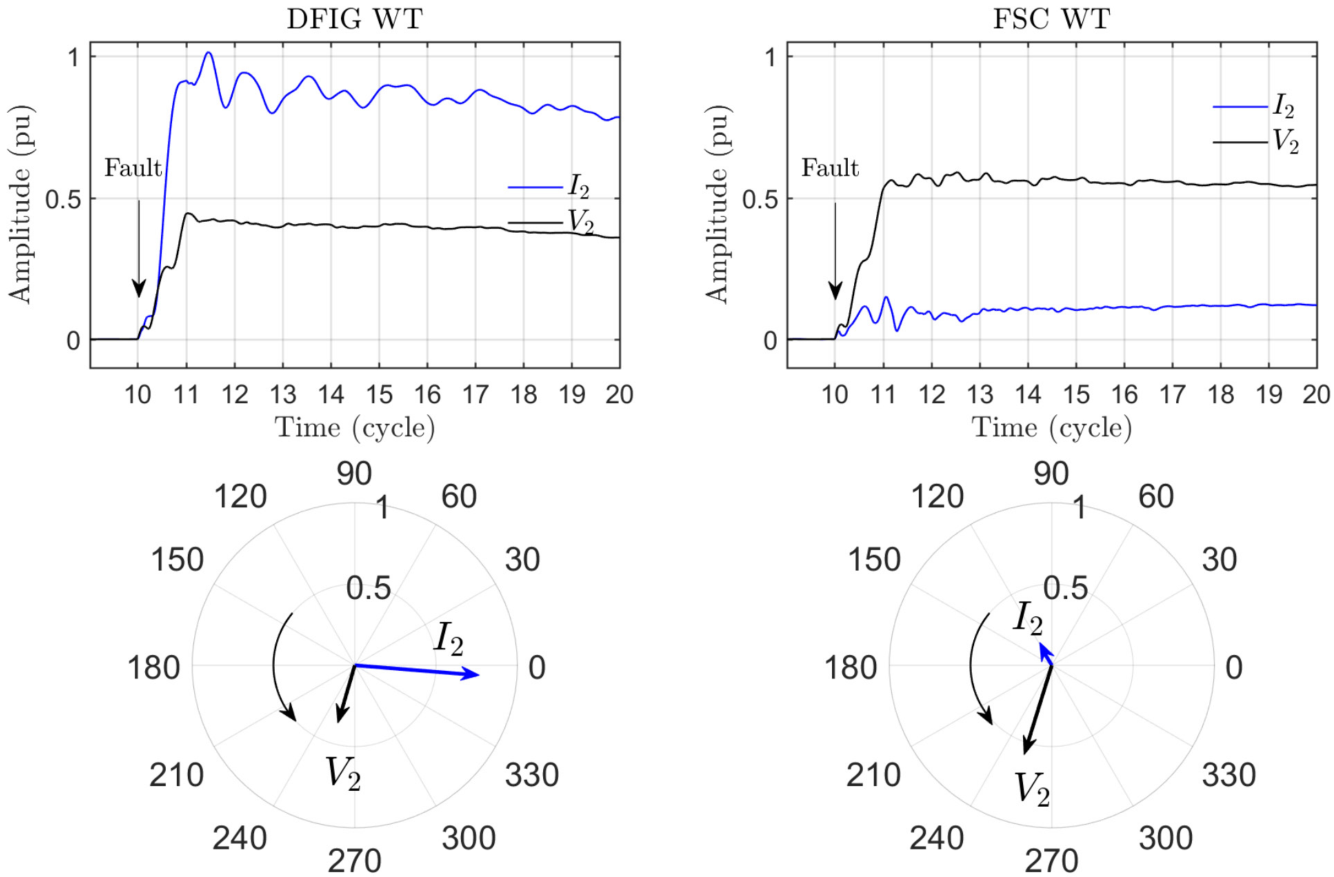

Figure 4-2: *Negative-sequence voltage and current - DFIG scenario (left) and FSC WTG scenario (right).*

Figure 4-3 shows field measurements from the fault response of a 1.2 MW solar plant for an AB fault. It is clear that approximately 1.5 cycles after the fault initiation, the negative sequence controller is activated and eliminates the negative sequence current provided by the solar plant. For the first 1.5 cycles, the response is uncontrolled.

Similar behavior can be observed in Figure 4-4, for a single phase to ground fault at a 22.5 MVA solar farm. The controller acts within approximately 1.5 cycles to eliminate the negative sequence current.

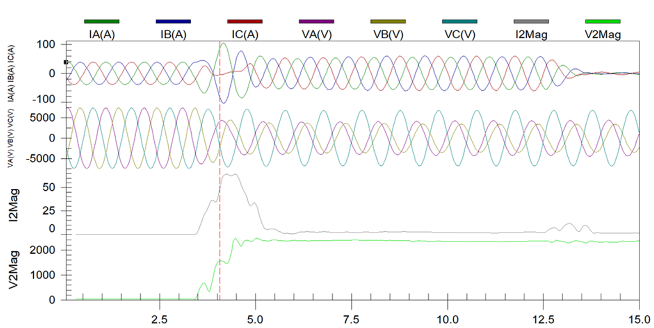

Figure 4-3: *Negative-sequence voltage and current of a solar plant.*

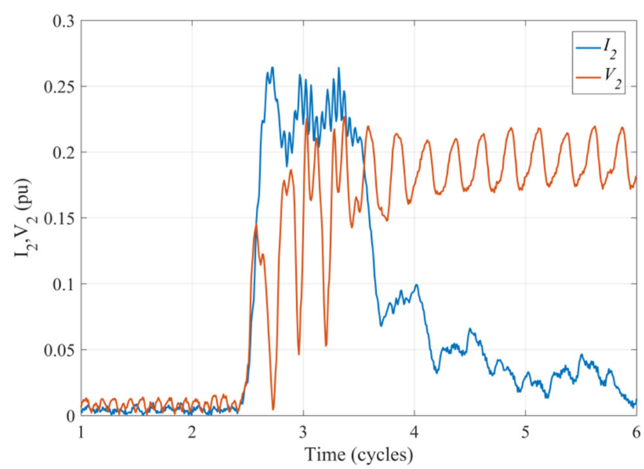

Figure 4-4: *Negative sequence voltage and current of a 22.5 MVA solar farm due to a single phase to ground fault*

Finally, Figure 4-5 shows the recorded negative-sequence fault current and voltage of an actual DFIG due to a phase-A-to-ground fault cleared after about 3 cycles [21]. As expected the DFIG injects negative sequence current which has a relatively low magnitude.

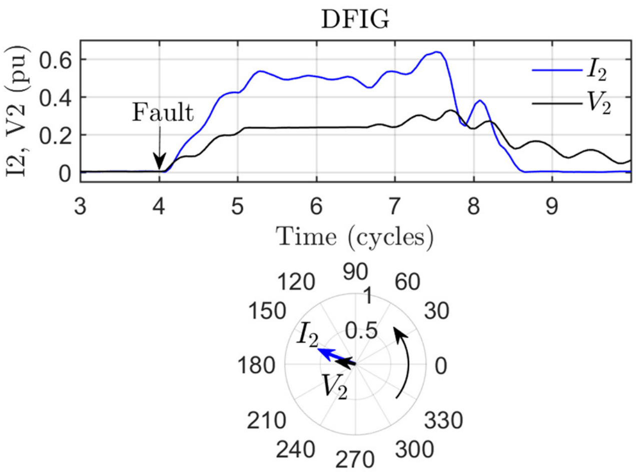

Figure 4-5: Negative sequence fault current and voltage of an actual DFIG WTG due to a phase-A-to-ground fault.

5 IMPACT OF INVERTER-BASED RESOURCES ON NEGATIVE-SEQUENCE PROTECTION SCHEMES

Given all the key differences between SGs and IBRs described before, protective relays set under the assumption of a conventional power system with SGs, are likely to misoperate under operating conditions with a high penetration of IBRs. It is therefore necessary to investigate the performance of protective relaying to ensure its reliability in the presence of IBRs. The focus of this paper is on protection schemes using negative-sequence quantities to carry out their protective function. Given the different negative-sequence fault current behavior of IBRs, as explained in Section 4, the negative-sequence-based protection schemes are prone to misoperation under IBRs. Simulation results comparing relay responses under the presence of FSC and DFIG WTGs are shown. The response of PVs is similar to that of a FSC WTG, assuming the same GSC control, so the simulations are not repeated for PV scenarios.

5.1 Misoperation of Instantaneous Negative Sequence Overcurrent (50Q/51Q)

50Q/51Q elements pick up when the amplitude of the negative-sequence current exceeds a pre-specified threshold. Their underlying operation principle is that an unbalanced fault causes a substantial level of negative-sequence current to flow through the relay, causing the operation of 50Q/51Q elements. This is an expected behavior under SGs due to the low impedance path provided by SG windings to the negative sequence current. Nevertheless, due to the high apparent equivalent negative sequence impedance of IBRs, the negative-sequence current may be smaller than the 50Q/51Q pickup threshold, and the elements may fail to detect the fault.

To illustrate this misoperation, let us consider the response of the 50Q/51Q elements of an overcurrent relay on bus 5 to the AB fault described in Section 2. These elements pick up when they see a negative-sequence fault current with an amplitude more than the pickup setting of 0.5 pu. The operation is successful under SGs since the amplitude of the negative-sequence fault current is 1.5pu. Nevertheless, under FSC WTG this amplitude is 0.12 pu (see Figure 5 1) which is not enough to operate these elements, and the 50Q/51Q elements fail to detect the fault. The misoperation does not occur under the DFIG WTG since the amplitude of the negative-sequence current is 0.75pu which is greater than the pickup threshold (see Figure 5-ºº1). This example suggests that WTG type (DFIG or FSC) adversely impacts the operation of the 50Q/51Q elements, and their misoperation is more likely under FSC WTG compared to DFIG WTG.

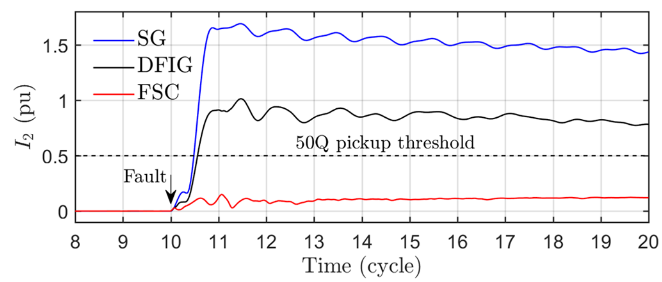

Figure 5-1: The amplitude of negative-sequence fault current measured by a 50Q element due to an AB fault.

Given that 50Q/51Q elements are commonly used in conjunction with other protective elements [5], [22], [23], [24], misoperation (failing to detect fault) of these elements may pose a risk to the reliability of the power system. References [25], [26] provide additional examples of 50Q/51Q misoperation.

5.2 Misoperation of Directional Negative Sequence Overcurrent (67Q)

The 67Q element may malfunction under IBRs for two reasons. The first is similar to that of the misoperation of 50Q/51Q elements. Similar to these elements, 67Q also has a pickup setting, and if the level of negative-sequence fault current becomes too low under IBRs, 67Q element may not operate. In such a case, 67Q does not declare a forward or reverse fault. An example of such a misoperation is the AB fault described before under FSC WTG whose corresponding negative-sequence current of 0.12 pu is insufficient to operate the 67Q element of a relay on bus 5 with a pickup setting of 0.2 pu. As a result, the forward fault is not classified as forward or reverse by the element. The 67Q element picks up correctly in case of DFIG WTG because the negative sequence current contribution is 0.75 pu. This example suggests that the misoperation of 67Q depends on the type of WTG (DFIG or FSC) and is more likely under FSC WTG.

The other cause of 67Q malfunction is the changed angular relation of negative-sequence voltage and current phasors under IBRs. The element determines the direction of a fault under the assumption that a forward/reverse fault causes a phase angle difference of -90°/90° between the negative-sequence voltage and current phasors. This assumption may not hold under IBRs, causing the element to malfunction. A North-American utility has recently reported such a misoperation where a negative-sequence directional element malfunctions due to the changed angular relation under DFIG WTG [27]. References [25], [26] have also provided examples of 67Q misoperation due to the changed angular relation under FSC WTG. Figure 5-2 shows an example of such misoperation for the AB fault of Section 2 and a 67Q element on bus 5 looking towards the transmission line connecting bus 5 to bus 6. As shown, under DFIG and SG, the apparent phase angle difference between negative-sequence voltage and current is -92° and -101.6°, respectively. Thus, the apparent negative-sequence impedance vector falls within the forward zone, and the 67Q element successfully declares the fault direction as forward. Nevertheless, under FSC WTG the angle becomes 131.4° which is within the reverse zone and the fault direction is mistakenly declared reverse. This example further shows that the performance of 67Q depends on the type of WTG and its controls. More details on the performance of 67Q due to IBRs can be found in [25].

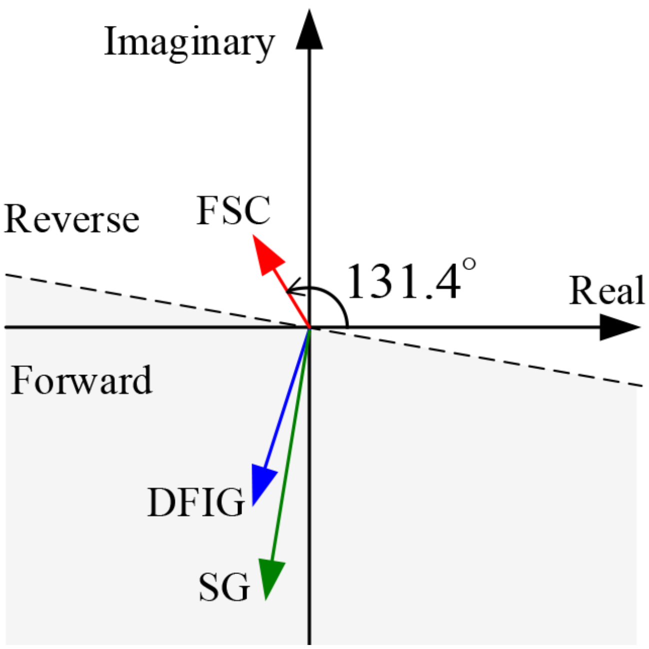

Figure 5-2: *67Q misoperation case: Apparent negative-sequence fault impedance under SG (green), DFIG WTG (blue), and FSC WTG (red).*

Given that a number of protection schemes use 67Q, the misoperation of this element poses a risk to the reliability of the power system. Communication-assisted protection, described next, is an example of such a protection scheme.

5.3 Misoperation of Communication-Assisted Protection

Reference [25] has shown the potential of misoperation of POTT scheme under FSC WTG. The cause of this misoperation is a malfunctioning 67Q element on one end of the transmission line. Due to this misoperation, the impacted relay mistakenly sees the line fault as a reverse fault and fails to send the permissive trip signal to the remote relay, thus causing an incorrect trip decision by the remote relay.

Reference [25] has further shown the misoperation of PUTT, DCB, and DCUB protection schemes due to IBRs. In all cases, the cause of misoperation is the malfunctioning of a 67Q element due to which the impacted relay communicates an incorrect permissive trip/block signal to the remote relay, thus causing an incorrect trip decision.

Similar to 67Q, the performance of communication-assisted protection is also impacted by the type of WTG. As [27] and [25] have shown, the misoperation may or may not occur under DFIG WTG. Thus, it is necessary to consider the type of a WTG (DFIG or FSC) and its controls in studying the performance of communication-assisted protection.

5.4 Incorrect Fault Identification (FID)

As shown in Section 3, the characteristic of negative sequence quantities, i.e., phase angle between negative sequence voltage & current, may be different under IBRs compared to SGs. Such a change may negatively impact the performance of FID which operates based on an angle between negative sequence and zero sequence current phasors. This misoperation can also be shown for the fault of Section 2. A phase-C-to-ground fault has been placed at the same location, and a distance relay incorporating an FID scheme is added on bus 8 looking towards the fault. The FID scheme should declare this fault as a phase-C-to-ground. Figure 5-3 shows the results. Under SG, the FID scheme sees a phase angle difference of about 115° between the negative- and zero-sequence current phasors (IA2 and IA0). This phase angle difference corresponds to the green sector, and the scheme successfully declares the faulted phases as CG. Nonetheless, under FSC WTG the measured angle difference changes to about 172° which falls within none of the sectors, and the FID scheme does not detect the faulted phase. The cause of this incorrect faulted phase identification is the changed phase angle of negative-sequence current phasor due to FSC WTG.

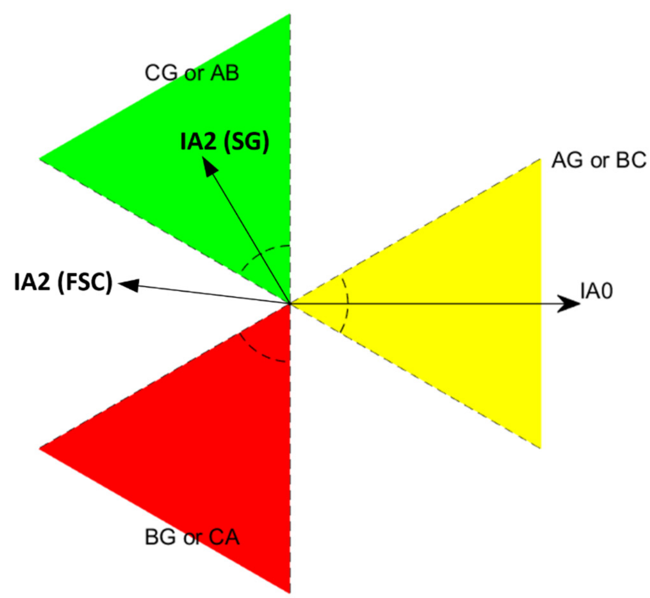

Figure 5-3: *FID misoperation case study: IA2 and IA0 phasors superimposed on the phase selection sectors under SG and FSC WTG for a phase-C-to-ground fault.*

Reference [25] has presented further examples of FID malfunction due to FSC WTG. In these simulations, the incorrect faulted phase identification did not occur under DFIG WTG which underlines the importance of accurately modeling the WTG depending on its type (DFIG or FSC).

5.5 Factors Affecting Relay Misoperation

Sections 4 and 5 have shown that negative sequence current contribution from a WTG is dependent on its type (FSC or DFIG) and hence impacts the performance of negative-sequence-based protection schemes. Other influential factors include GSC control mode (CSC or DSC) and the operating conditions of a WTG including the number of units in service [25]. It is therefore necessary to consider these factors in application of protection schemes. Wind speed may have an indirect impact as reduced speed will reduce the active current component and provide more room for reactive component.

5.5.1 Wind Turbine Type

WTG type (FSC or DFIG) impacts the performance of all considered negative-sequence protection schemes. The misoperation of 50Q/51Q is more likely under FSC due to the generally smaller negative-sequence fault current contribution. 67Q malfunction is possible under both DFIG and FSC. Communication-assisted protection is also prone to malfunction under both DFIG and FSC. Based on the results of [25], incorrect FID may occur under FSC.

5.5.2 GSC/RSC Control Mode

GSC control mode (CSC or DSC) may impact the operation of both 50Q/51Q and 67Q.

The results presented in Sections 5.1-5.4 assume CSC GSC control. The likelihood of 50Q/51Q misoperation is less under DSC due to the increased negative-sequence fault current injection enforced by the control system, and the impact of control mode is more considerable under FSC WTG. For DFIG WTGs the GSC control mode does not affect significantly the relay performance. However, the RSC negative sequence current control based mitigation methods may cause relay misoperation problems as the negative sequence fault current contribution of the DFIG will be decreased significantly.

The impact on 67Q is also more pronounced under FSC compared to DFIG due to the considered method used to mitigate torque pulsations in DFIG WTGs. Reference [25] has shown that 67Q misoperation occurs under both CSC and DSC in FSC WTG but does not occur under either control mode in DFIG WTG.

5.5.3 Number of Wind Turbines in a Wind Plant

The number of WTG units in service at a wind plant impacts the performance of all considered negative-sequence protection schemes. The reason is that both the amplitude and the phase angle of the negative-sequence fault current contribution of a WTG are a function of the number of units in service.

5.5.4 Wind Speed

If CSC is used, wind speed has little impact on the amplitude or the phase angle of the negative-sequence fault current contribution of a WTG, regardless of the type of the WTG under study [25]. This suggests that, under CSC, wind speed is not expected to significantly impact the misoperation of 50Q/51Q, 67Q, or other negative-sequence-based protection schemes. However, if there is a requirement on negative sequence component of the IBR fault current and the converter current limits are hit due to a severe voltage sag condition invoked by a close by fault, then wind speed will have an impact since reduced wind speed translates into reduced power output hence reduced active current component. This will provide more room for negative sequence reactive current.

6 SUMMARY

The objective of this white paper was to summarize the distinct fault response characteristics of IBR compared to SGs, with focus on the negative sequence current contribution during unbalanced faults. Given that several protection schemes are relying on negative sequence components to make a trip decision, the paper also analyzes and demonstrates through simulation examples and actual field events, the impact on negative-sequence based protection schemes and potential relay misoperations.

IBRs are current limited devices. Even when required to inject negative sequence current during unbalanced faults, for example as per the German grid code, the magnitude of this current would be limited. The limitation exists because the phasor sum of positive sequence current (active and reactive) and negative sequence current in any given phase cannot exceed the current limit of the converter. As such, the full extent of this behavior on traditional protection schemes is still unknown especially when the penetration of IBRs is significantly high throughout the interconnection.

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APPENDIX A: TEST SYSTEM

Figure A-1 shows the test system of this paper which is a 13-bus transmission system representing a simplified model of a portion of a North American power system incorporating 5 generator locations denoted by G1-G5. The generators at locations G1-G5 have been assumed to be SGs or IBRs to provide different generation scenarios. The simulated fault is denoted by AB representing an unbalanced phase-A-to-phase-B fault on bus 6 of the test system.

FOR MORE INFORMATION

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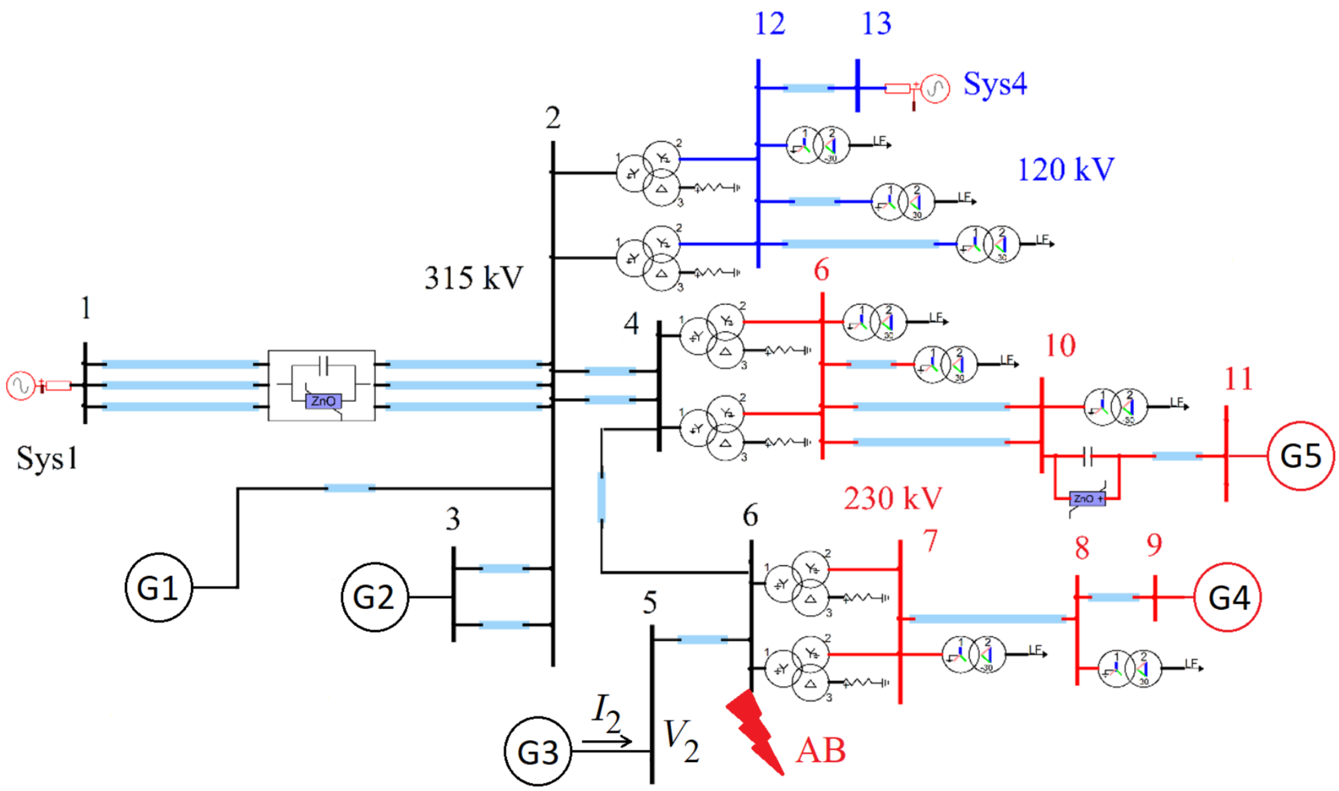

Figure A-1: *Test system for the simulation of the negative-sequence behavior of SG and IBR*

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