Ground Directional Protection Assesment in Inverter Dominated Distribution Networks

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***Abstract*–Inverter-Based Resources (IBRs) are challenging traditional line protection systems, that have been designed and developed over the years considering the fault characteristics of synchronous generator dominated power systems. The response of IBRs under faults is mainly driven by the inverter control design that can vary across different manufacturers. This study focuses in assessing the performance of negative and zero sequence voltage polarized ground directional elements in a Medium Voltage (MV) distribution grid with increased penetration of Photovoltaic (PV) systems. A system has been developed, modelling a part of a distribution grid and utilizing detailed ElecrtoMagnetic Transient (EMT) models to emulate the behavior of IBRs. The design of the substation protection scheme includes an 11 kV blocking scheme employing ground directional elements. The system is simulated in a real time environment and Hardware In the Loop (HIL) tests are performed with actual protection relays utilizing the industry standard IEC 61850 protocol for the communications. The performance of the blocking scheme is examined under different configuration scenarios, with the results indicating that under certain conditions, with heavy IBR fault contributions, the protection scheme is impacted negatively.**

Keywords— Blocking Scheme, directional protection, grid faults, inverter, sequence analysis, IEC 61850.

I. Introduction

Environmental concerns have led governments around the globe to establish regulations and subsidy schemes for massive deployment of Renewable Energy Sources (RES). The rapid growth of RES comes with many challenges, including the performance of existing power system protection schemes [1], [2]. It is well understood in the industry that the behavior of IBRs is very different compared to conventional generators under fault conditions. Existing protection applications have been developed over the years considering the fault contributions from synchronous machines. Fault currents provided by synchronous generators are predictable irrespective of the manufacturer and can be modelled with a circuit including a voltage source behind a transient/subtransient impedance (depending on period of interest). On the other hand, IBRs response during faults is inconsistent across manufacturers and highly depends on the bespoke control system design. In this sense, the injection of negative sequence currents, on which many protection functions depend on, vary across designs both in magnitude and angle relationships. Furthermore, IBRs are usually three wire interconnected with no zero sequence contribution unless the interface transformer is grounded on the utility side.

In [3], a study undertaken by Sandia National Laboratories in collaboration with manufacturers of protection relays and inverters, utilized a study system that includes EMT models generated from the actual control firmware of the inverters. The focus of the investigation is the IBR negative sequence current injection under unbalanced faults. The currents and voltages obtained through selected EMT simulations were played back into the actual protection relays with typical settings to assess the performance of different protection functions. The results demonstrate that the IBR negative sequence current injection during unbalanced faults is inconsistent, both in magnitude and phase angle relationship across different designs and thus, the security of negative sequence ground directional elements cannot be guaranteed. These findings are also supported through actual field events experienced in [4] and [5]. Standardization of the IBR negative sequence injection under unbalanced faults is therefore important to maintain the protection systems performance.

The study in [6] shows that for full converter wind turbines (Type 4) the negative sequence current for a phase-to-phase ground fault rotates with respect to the negative sequence voltage, as it appears to have a higher frequency, challenging the performance of the ground directional elements. In [7], the overcurrent threshold settings that supervise the directional elements are increased to a level that improves security for the directional elements but at the same time maintain sensitivity under fault contribution from synchronous generators or Doubly Fed Induction Generator wind turbines (Type 3).

Under certain conditions where the interface transformer is grounded, zero-sequence elements could be used reliably to detect the fault direction, however this is not always practical as the zero-sequence quantities calculation may be impacted by the mutual coupling between transmission lines. BC Hydro in [8] has introduced a strategy by which it requires the grid integration of IBRs only via transformers with effective grounding on the utility side to achieve reliable protection for ground faults using zero sequence currents. The practice includes the use of line current differential protection when secure tele-protection channels are available or alternatively the use of a Permissive Over-reaching Transfer Trip (POTT) scheme. Phase to phase under-voltage protection is provided as a backup to phase distance relays not picking up at the inverter interface and to account for a tele-protection failure. It is ensured that the phase to phase under-voltage element does not cause violation of the fault ride through requirements.

The investigation undertaken in [9] analyzes an external fault to a 138 kV transmission line interconnecting a 420 MW solar facility. The fault identification logic and the POTT scheme by overreaching Zone 2 distance and neutral directional overcurrent are challenged due to the unstable behavior of the negative sequence current throughout the fault. It was demonstrated that for the case under study, incremental quantity directional elements could be used reliably to

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determine the fault direction. A fault phase selection logic based on incremental quantities, complemented with improved phasor-based identification logic that uses negative and zero sequence voltage in addition to the negative and zero sequence current was evaluated and implemented in a new wind farm connection project.

The studies performed in the literature concentrate on the issues arising for protection schemes at the transmission level. In contrast, this work focuses at the distribution level and performs an industrial-oriented investigation and a performance evaluation for protection schemes implemented at distribution substations. Through this investigation, which is the key contribution of this paper, significant challenges for the distribution level protection schemes have been identified that can deteriorate the reliability of modern distribution grids and some insights are provided to overcome these challenges. The focus of the study is on the ground directional protection elements, used as part of an 11 kV substation blocking scheme. Simulations of a study system in a real time environment and HIL tests with commercial protection relays are performed to illustrate the problem. The followed methodology proves to be very effective as it allows the testing of protection devices under realistic conditions. The massive deployment of IBRs complicates the exercise of calculating and implementing protection settings, therefore more advanced simulation tools and test setups will be required to assess the protection performance and to design adequate protection schemes able to respond properly under the new circumstances.

The following of this paper is organized as follows. First, in Section II the background theory is provided for ground directional protection and response of IBRs under fault conditions. Then, in Section III, the system and test setup for testing the protection scheme of an 11 kV substation with the presence of IBRs is described and the test results are presented. Finally, the paper concludes in Section IV.

II. Background Theory

A. Ground Directional Protection

The background theory of the negative sequence voltage polarized directional element is well described in [10],[11],[12] and [13]. The traditional negative sequence directional element uses the angle relationship between the negative sequence voltage and negative sequence current to determine the fault direction. For forward faults the negative sequence current leads the negative sequence voltage by 180 degrees minus the characteristic angle of the line. The stronger the source is, the lower the negative sequence voltage measured at the relay becomes and thus, an alternative approach uses the negative sequence impedance for determining the direction. In this case, the relay calculates the negative sequence impedance vector ($\mathbf{z}_2$) according to voltage and current measurements, as given by (1),

$$\mathbf{z}_2 = Z_2\angle\theta_{z2} = \frac{\mathbf{v}_2}{\mathbf{i}_2} \qquad (1)$$

Where $\mathbf{v}_2$ and $\mathbf{i}_2$ is the voltage and current negative sequence phasors calculated by a real-time analysis performed within the protection relay. The negative impedance vector can be expressed as an impedance with Z_2 amplitude at a θ_{z2} angle. Then, the co-linear projection of $\mathbf{z}_2$ at the direction of the positive sequence line impedance setting of the relay (θ_{z1}^*) is determined as $Z_{2\text{-clp}}$, and can be calculated according to (2).

$$Z_{2-clp} = Z_2\cos\left(\theta_{z2} - \theta_{z1}^*\right) \qquad (2)$$

Therefore, by comparing the calculated negative sequence impedance with a forward (Z_{F2}) and reverse (Z_{R2}) impedance threshold the fault direction can be determined. Fig. 1 shows the Negative Sequence Impedance plot indicating a reverse fault (red plot) since $Z_{2\text{-clp}}$ is greater than Z_{R2}. The calculation of the negative sequence impedance is only performed if the negative sequence current exceeds a supervising negative sequence overcurrent setting for both forward and reverse faults. The principle of operation for the zero-sequence voltage polarized directional element is the same but the zero sequence impedance is calculated instead. Within the relay the priority between the negative and zero sequence voltage polarization for the directional element is settable and can be adjusted based on system conditions.

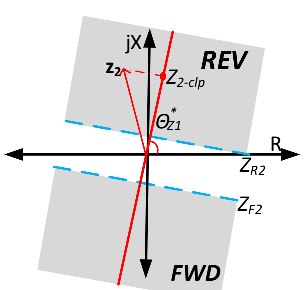

Fig. 1. Negative sequence impedance plot.

B. Fault Contribution from IBRs

As described in the Introduction, the response of IBRs to unbalanced faults is mainly driven by the inverter control system design. The main goal is to protect the power electronic devices by keeping the short circuit currents within their thermal limits (rated currents) of the converter. Fault contributions from IBRs are therefore of low magnitude with the negative sequence current varying across designs both in magnitude and phase angle according to the inverter controller design. At the same time zero sequence contributions depend on the interface transformer grounding arrangement.

Another objective of the inverter control system is to meet industry standards, such as the low voltage ride through requirement which specifies a zone for which IBRs should remain in service under a voltage sag. During the voltage sag, it is required by the inverter to inject positive sequence reactive currents to support the voltage depression. Recently the German Grid Code was modified to also include a requirement for negative sequence current support [8]. Inverters are also required to maintain a balance across services provided as described in [14].

The system used for this investigation includes only solar inverters that interface with the medium voltage grid via 11 kV/0.4 kV Dyn11 vector group transformers. As a result, there

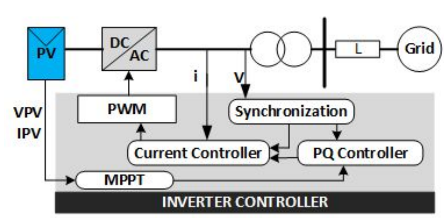

Fig. 2. Grid side converter controller

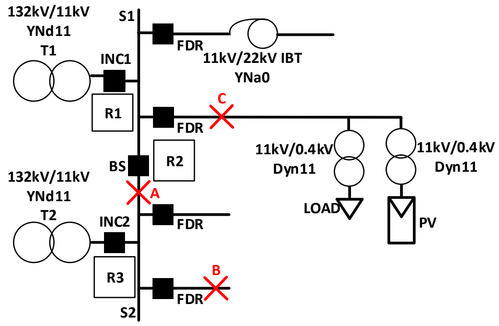

Fig. 3. Study system single line diagram

is no zero-sequence contribution for faults on the grid side. The control system of a grid side converter that integrates PV plants to the grid is shown in Fig. 2. The synchronization module is responsible for injecting the power produced in a synchronized manner, the Maximum Power Point Tracking (MPPT) unit to extract the maximum power from PV panels, the PQ controller to regulate the active and reactive power injection, the current controller to regulate the current injection, and finally the Pulse Width Modulation (PWM) hardware peripheral to generate the pulses that drive the inverter [15]. Since the behavior of IBRs under fault conditions depends on the control system design, for this study the complete grid side converter controller is included in the model for performing the real time HIL tests.

III. Assesment of Ground Directional Protection

A. *System and Testbed Arrangement Description*

The single line diagram of the system under study is shown in Fig. 3. The substation is fed via two 132 kV/11 kV 31.5 MVA grid transformers with a YNd11 vector group. The MV side of the grid transformers is grounded via zig zag earthing transformers. The 11 kV feeder circuits include a combination of loads and PV plants connected at MV via 11 kV/0.4 kV Dyn11 distribution transformers. In addition, there is a feeder circuit connected on Bus Bar (BB) Section 1 (S1) supplying an Inter-Bus 11 kV/22 kV auto-transformer (IBT). This is a typical arrangement for supporting the ongoing effort of upgrading part of the MV distribution network from 11 kV to 22 kV.

The protection scheme design includes an 11 kV blocking scheme that significantly reduces the fault clearing time for BB faults. The feeder circuits are protected via non-directional Over-Current (OC) and Earth Fault (EF) Inverse Definite Minimum Time (IDMT) curves coordinated appropriately with upstream and downstream protection relays. For a fault on any of the feeder circuits, non-directional OC and residual EF High Set (HS) elements are configured to send an instantaneous block to OC and EF Definite Time (DT) elements configured for tripping the Bus Section (BS) and the incomer connected on the same BB Section with the faulted feeder. The blocking signal is released in case of a feeder Circuit Breaker (CB) failure. In Fig. 4, part of the relay logic for the Incomer 1 Relay (R1) and the BS Relay (R2) is shown. The convention used for R2 is that a forward fault is from S1 to S2, whereas for R1 and R3 a forward fault is towards the BBs. As shown in Fig. 4, R2 includes non-directional OC and EF IDMT elements but also Reverse (REV) and Forward (FWD) DT Elements for OC and EF for Tripping (i.e., REV OCDT, REV EFDT, FWD OCDT, FWD EFDT). The incomer relays (R1, R3) also include non-directional OC and

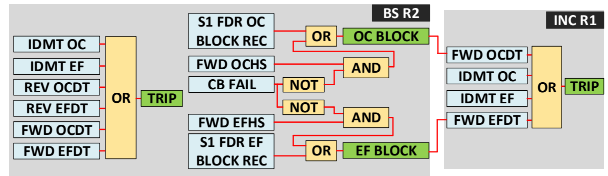

Fig. 4. Incomer 1 (R1) and BS (R2) relay logic.

EF IDMT elements and only forward OC and EF DT elements (i.e., FWD OCDT, FWD EFDT). Reverse OC and EF elements are not required in the incomer relays since fast protection is provided by the transformer unit protection zone.

Considering a fault on a feeder circuit connected on S2 (e.g., fault location B), the R2 and R3 forward DT elements are blocked from the relay protecting the corresponding feeder which should trip first. Similarly, for a feeder fault connected on S1 (e.g., fault location C) the R2 reverse DT and the R1 forward DT elements are blocked by the feeder relay protecting the faulty feeder. In case of a feeder CB failure condition, the block signal will be released for the upstream relays to allow tripping. For example, for a fault at location B and a feeder CB failure, the OC/EF DT forward element in R2 and R3 will be released for tripping, with incomer 1 remaining in service. Now, considering a BB fault at location A, no blocks should be received from the feeder relays and the R3 OC/EF forward element will trip incomer 2 (INC2). Further, the R2 forward OC/EF HS elements will send a block to the forward OC/EF DT elements of R1 (released only in case of a BS CB failure) and the forward OC/EF DT element in R2 should trip the BS CB.

The substation communication supporting the blocking scheme is based on the IEC 61850 protocol. GOOSE signals are configured between the protection relays to communicate the required blocking signals. The laboratory testbed is implemented within the KIOS Center of Excellence research infrastructure (https://www.kios.ucy.ac.cy/power-systems-testbed/) for testing the scheme in a HIL arrangement, as shown in Fig. 5. The study system of Fig. 3 is modelled and simulated in real time using the OPAL real time simulator (OP 5700) [16]. The logic for relays R3 and R2 was applied using the SEL 451 and SEL 421 relays respectively and standard protection settings have been applied, whereas R1 was modelled in the real time simulator [17],[18]. In general, the DT trip elements apply a 200 ms time delay and the HS elements a 0 s delay. Low level voltage and current from the OP 5700 simulator are amplified using an Omicron 356S amplifier before injected into the protection relays [19]. GOOSE signals are configured via the SEL 2740S ethernet switch between the two relays for blocking but also from each relay into the OP 5700 simulator for the CB tripping [20]. Time synchronization is achieved via IRIG-B using an SEL 2407 satellite clock [21]. For the study, a fault at location A is

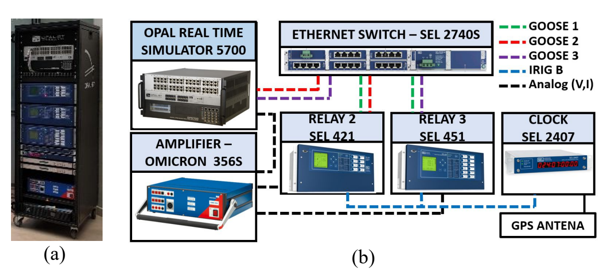

Fig. 5. HIL testbed arrangement: (a) photo of the setup, (b) setup

TABLE I. RELAY ELEMENTS DESCRIPTION

Name	***Description***	***Relay Applied***
67G1T	DT residual ground directional overcurrent element. Forward ground conditioned.	SEL 421 SEL 451
67G3T	DT residual ground directional overcurrent element. Reverse ground conditioned.	SEL 421
F32QG /F32V	Forward negative / zero sequence voltage polarized ground directional element.	SEL 421
R32QG /R32V	Reverse negative / zero sequence voltage polarized ground directional element.	SEL 421
PSV26	Protection variable used for communicating a forward block (via GOOSE to incomer 1).	SEL 421
PSV27	Protection variable used for communicating a reverse block (via GOOSE to Incomer 2).	SEL 421
PSV30	Protection variable used to send a BS trip command (via GOOSE to OPAL-RT).	SEL 421
PSV21	Protection variable used to flag a received block.	SEL 451
PSV32	Protection variable used to send an incomer trip command (via GOOSE to OPAL-RT).	SEL 451

simulated and the response of R3 and R2 is assessed for different configurations in the following sections.

B. Case Study – 11kV Blocking Scheme Security Assesment

The performance of the 11 kV blocking scheme is assessed for different configuration scenarios to study the impact of the IBR contributions. For the simulations, the total PV generation prior the fault is 9 MVA at unity power factor, with a demand of approximately 5 MVA. For analyzing the performance of the relays for different configurations the relay events are extracted using Synchrowave software in COMTRADE format, which is a standard format that relays use to store analog and digital status signals related to power system disturbances (2000 samples per second) [22]. For more comprehensive analysis, the events presented in Table I provides a description of the elements used for the two relays. The results for the three configurations under study follow:

1) Configuration 1: T1 and T2 operate in parallel

In this scenario the grid transformers T1 and T2 operate in parallel. For a phase to phase ground fault (LLG) at location A with 0.2 Ohms fault resistance (constant for all configurations) the extracted relays events for R2 are shown in Fig. 6. It can be concluded that in this case the PV contribution is insignificant, as the conventional source (T1) dominates and the relay decisions are as expected. A forward fault is declared (F32QG) by R2 and a forward block is send to the 67G1T element of R1 via protection variable PSV26. The 67G1T element of R2 times out in approximately 200ms as expected and trips the CB via PSV30. The phasors snapshot, shown in Fig. 6, is at the instant indicated by the orange bar with reference to the negative sequence voltage, however this was consistent across the duration of the fault. The R3 events are not shown due to space constraints but the 67G1T element also trips correctly in approximately 200ms.

2) Configuration 2: T1 and IBT circuit out of service.

For configuration 2, grid transformer T1 and the IBT circuit are taken out of service. As a result, for a LLG fault at location A, there is insignificant flow of zero sequence current through the BS, with only positive and negative sequence IBR current contributions. From the events extracted for R2 (Fig. 7) it can be observed that the fault

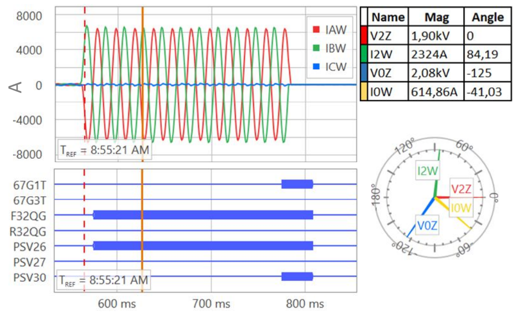

Fig. 6. SEL 421 (R2) events for Configuration 1.

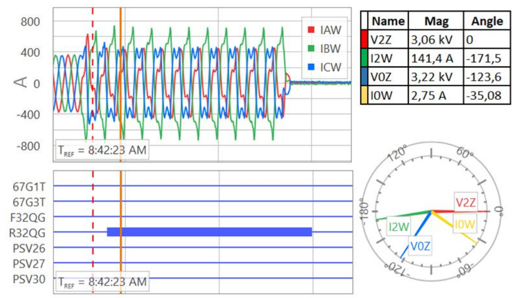

Fig. 7. SEL 421 (R2) events for Configuration 2.

currents supplied from the IBRs are severely distorted. The relay incorrectly declares the fault as being in the reverse direction (R32QG). The phasors diagram snapshot is for the time instant indicated by the orange bar, however during the fault the negative sequence current rotates with respect to the negative sequence voltage, but the reverse direction was retained throughout the fault. Since there was no zero sequence contribution through the BS the 67G3T element did not pickup. The records for R3 are not shown due to space constraints, however the relay correctly responded declaring a forward direction and tripped in approximately 200ms. In such a scenario IBRs would follow by tripping on islanding protection.

3) Configuration 3: T1 out of service and IBT in service

Configuration 3 is similar to configuration 2 with the IBT circuit being in service. As a result, for a LLG fault at location A, the IBT contributes zero sequence current through the BS relay due to circulating currents via the IBT neutral. The event files as extracted from R2 are shown in Fig. 8. The negative sequence directional element incorrectly declares the fault in the reverse direction (R32QG) and through variable PSV27 incorrectly sends a reverse block to R3. By observing the R3 event files (Fig. 9), a block command is received (PSV21) and even though the fault is declared in the correct direction (F32QG), due to the conventional source contribution through T2, the 67G1T element is blocked. After approximately 200 ms the BS element trips incorrectly on the reverse 67G3T element, releasing however the block being sent to R3. This allows the 67G1 element to start timing and eventually trips via PSV32 after around 200 ms. The total fault clearing time increased from 200 ms to over 450 ms, defeating the overall scheme philosophy.

The test was repeated however this time a priority was given to Zero Sequence Voltage Polarization over Negative Sequence Voltage Polarization. As shown in Fig. 10, R2 correctly declares the fault being in the forward direction

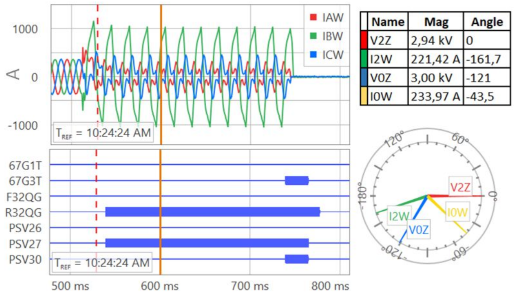

Fig. 8. SEL 421 (R2) events for configuration 3.

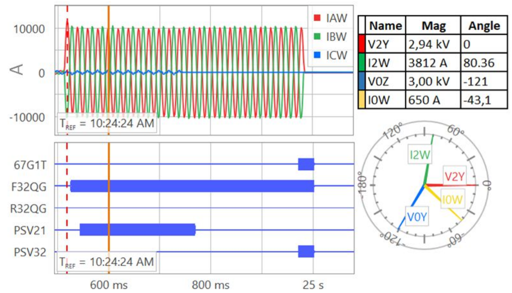

Fig. 9. SEL 451 (R3) events for configuration 3.

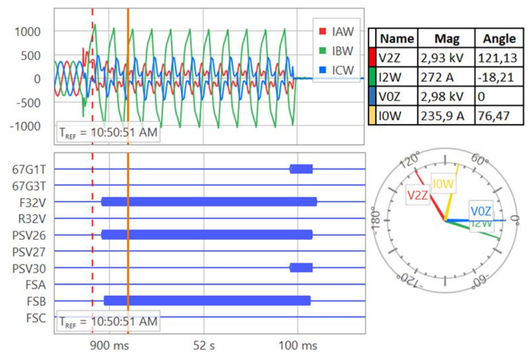

Fig. 10. SEL 421 (R2) events for configuration 3 (zero seq. polarized).

(F32V) and sends a block to R1 via PSV26. 67G1T element times out in 200ms and as expected trips the BS CB via PSV30. It can be observed however that the fault identification logic fails to correctly identify the fault as phase-*a* to phase-*b* to ground, and instead flags the fault as being a single phase-*b* to ground fault. This is because of the resulting phase relationship between the negative and zero sequence currents.

IV. Conclusions and Recomendations

This paper studies the effect of the IBRs fault contribution on an 11 kV blocking scheme, utilizing ground directional elements. A study system that includes detailed models of the IBRs control system was developed and real time HIL tests were performed to assess the scheme under different running arrangements. It is seen that the negative sequence directional elements are prone to maloperation when a strong conventional source is not contributing to the fault resulting in a significantly slower fault clearing time. When zero sequence current flow is allowed zero sequence directional elements seem to correctly identify the direction of the fault; however, the scheme still suffers from correctly identifying the fault type. For maintaining the sensitivity of the protection scheme it is proposed that directional blocking for the BS relay is disabled when one of the incomers is open. This will ensure that no incorrect blocking signals are sent to the incomer relays (the feeder relays block signals are maintained), however the selectivity is affected as for a BB fault there is a possibility of isolating a BB section when not required. This approach is biased towards sensitivity rather than selectivity and can be accepted for this abnormal running arrangement. An alternative solution would be to increase the forward and reverse negative sequence overcurrent thresholds above the expected negative sequence contributions from the IBRs, however this may affect sensitivity in the normal condition. The authors have great interest in providing a solution to the problem via an improved inverter control system design that controls the negative sequence current contributions and will be working towards this direction in the future.

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