

Impact of Grid-Connected Inverters on Medium-Voltage Grid Currents During Phase-to-phase Faults

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Abstract—The growing incorporation of renewable energies (RE) into France’s Enedis medium-voltage grid via static converters necessitates a thorough assessment of their impact, both under typical operating conditions and in the event of faults. Understanding this issue is vital for ensuring the effective operation of protection relays at the substation level, distinct from those at the electrical energy producers sites due to variations in behavior and contribution arising from different control mechanisms compared to synchronous machines.

This project has two primary objectives. Firstly, it aims to ensure that the grid-connected inverter (GCI) we intend to deploy adheres strictly to the medium-voltage grid codes, including Low Voltage Ride Through (LVRT) and potential dynamic voltage support during grid faults. This is imperative as these requirements may not be part of Enedis technical specifications, and compliance may vary among electrical energy producers. Thus, it is pertinent to investigate this scenario. Secondly, we seek to analyze the behavior of the GCI and its influence on the measured current at the source substation during phase-to-phase faults on the medium voltage network and the potential impact on fault currents. This is significant as the settings of the overcurrent protection on the Enedis side rely on phase-to-phase fault currents. By gaining insights into the GCI’s operation and its effects on the overcurrent relay (OC) of the electrical network during faults, we aim to enhance the resilience and efficiency of electrical systems.

Preliminary findings indicate that the GCI can impact the source substation’s contribution to faults by reducing current injection. This phenomenon may lead to relay blinding and malfunction if the influence of GCI is not appropriately considered.

To our knowledge, very few references address the issue of the impact of the GCI on the prospective current provided by the substation and therefore the impact on the settings of its associated protection relay.

Index Terms—renewable energies, grid-connected inverter, medium voltage grid codes, low voltage ride through, dynamic voltage support, phase-to-phase fault, overcurrent relay.

I. INTRODUCTION

Modern power grids are witnessing a substantial integration of renewable energies facilitated by static converters. This transition aims to reduce greenhouse-gas emissions [1], meet customer demands, and address energy costs [2] in the face

of rising prices for major non-renewable sources such as oil and coal [3]. Simultaneously, grid operators are confronted with significant challenges and responsibilities. They must ensure that this evolution in energy sources is well-controlled and proceeds smoothly, all while maintaining optimal energy quality and maximum availability, and ensuring the maximum protection of grid equipment and consumers. In this paper, we will focus specifically on the protection scheme of the distribution network. The major issues to be investigated include cases where a fault occurs in the downstream feeder where the renewable energy (RE) is connected; the objective is to examine the effects of integrating these renewable energy sources and their response during a three-phase fault on the relay settings of the feeder. Many studies have discussed the impacts of inserting renewable energy into medium voltage (MV) grids; for instance, [4] addresses this issue by modeling the converter as a synchronous machine, demonstrating that the relay setting range widens in the presence of renewable energy. Another study, [5], considers the behavior of photovoltaic (PV) systems as similar to permanent magnet synchronous generators, both having almost the same fault current limitations. Their results indicate that renewable energy modeled as a PM-SG will not severely influence the distribution network. However, it is important to note that all these studies treated the converter as a synchronous machine, which may deviate from the real behavior of an inverter during fault conditions and could lead to incorrect results. [6] presents a three-phase short-circuit current model for both a typical inverter and synchronous machine, along with simulation results for a 7.5 MW implementation on a Canadian network. His results show that the distributed generation (DG) has no contribution to the fault as it disconnects rapidly when a fault occurs. However, this study does not take into consideration the actual grid code requirements, which mandate ride-through capabilities for DGs as well as dynamic voltage support (DVS). The operational behavior of an inverter on an electrical grid during a fault is dictated by its control mode. The inverter can operate in positive sequence, negative sequence, or a simultaneous combination of both modes. The predominant control mode is

positive sequence control. Regarding the injection of negative sequence current, there are currently no specified requirements. Consequently, negative sequence current is typically suppressed to zero as observed in [7] and [8]. In this paper only positive sequence control will be adopted. It is essential to highlight that the positive voltage serves as the input for positive sequence control. In simpler terms, the injected currents will depend on the positive sequence voltage sag, ensuring the preservation of a three-phase and balanced configuration. At this stage, the inverter can efficiently transmit both active and reactive power in accordance with the requirements set by network managers.

II. GRID CODE REQUIREMENTS

Integrating renewable energy sources into the grid through static converters poses numerous challenges, among them being the risk of these systems disconnecting during abnormal grid conditions. Such disruptions can have significant repercussions, particularly if the installed capacity is substantial, potentially leading to blackouts or grid failures. Grid codes, which vary between countries, play a critical role in establishing guidelines for the seamless integration of renewable energy into the grid. These codes primarily aim to ensure a dependable, available, and secure power supply. Compliance with these grid codes is imperative for the smooth and stable operation of the entire power grid, as underscored by [6]. These standards outline specific regulations, particularly concerning voltage and time constraints, that govern the connection and disconnection of renewable energy sources under both normal and abnormal circumstances. In instances of fault conditions, grid operators typically enforce two essential requirements: Low Voltage Ride Through (LVRT) and the injection of reactive power to provide voltage support during the ride-through process.

A. Low Voltage Ride Through

As per grid operators, Distributed Generation connected to the MV grid must stay connected even during fault conditions. This is crucial not only for the safety of utility workers and the protection of equipment but also for maintaining grid stability [9]. DG systems play a significant role in enhancing grid stability by providing additional power sources. During fault occurrences, the grid may suffer from voltage sags. DG systems that remain connected can assist in stabilizing the grid by injecting power and supporting voltage, thus mitigating the risk of blackouts and grid failures. The fundamental requirement, known as LVRT, is illustrated in Fig. 1 as given in [7], where t_0 is the fault ignition time and U_n is the nominal voltage value. This requirement delineates specific zones indicating the regions where DG remains connected and where disconnection occurs. They are defined as follow:

- Zone 1: Normal Operation Zone In this zone, the grid voltage remains within the standard operating range, and the renewable energy system functions under typical conditions.

- Zone 2: Ride-Through Zone During voltage sags, the system enters the ride-through zone. Here, it is engineered to withstand minor voltage sags without disconnecting from the grid. Depending on grid codes, the system may either halt or continue supplying power during these brief dips. Further details about this zone will be discussed in the subsequent section.
- Zone 3: Disconnection Zone If a voltage sag becomes severe, dropping below a critical threshold, the system may transition into the disconnection zone. In this zone, the renewable energy system is permitted to disconnect from the grid to safeguard itself from potential damage.

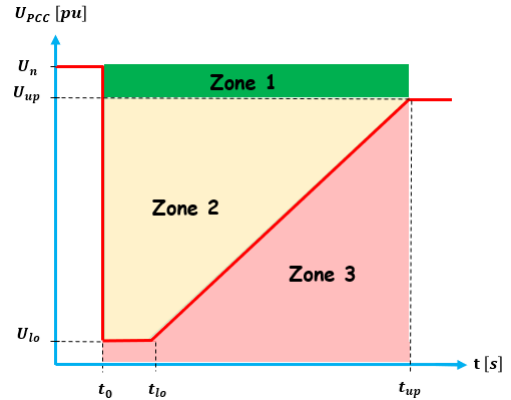


Fig. 1. Basic shape of an LVRT

The LVRT requirement is crucial for ensuring the continuous operation of DG systems during grid faults. The settings for the LVRT requirements can vary depending on the country. Table I presents the LVRT settings mandated by France, Germany, Denmark, South Africa, and China for Distributed Generation connected to the Medium Voltage grid, as outlined in [10], [7], and [8]. Now, focusing on the ride-through zone, a

TABLE I
GRID CODES SETTINGS FOR LVRT

Country	U_{lo} [pu]	U_{up} [pu]	t_{lo} [s]	t_{up} [s]
France	0.05	0.85	0.15	1.5
Germany	0	0.9	0.15	1.5
Denmark	0.2	0.9	0.5	1.5
China	0.2	0.9	0.15	2
South Africa	0	0.85	0.15	2

pertinent question arises: how does DG respond and what does it inject during this brief period? The answer lies in adherence to grid codes specifying the power to be injected into the grid by DG systems.

B. Dynamic voltage support

During periods of grid faults, DGs, including those equipped with LVRT functionalities, may contribute to supply the grid. The specific nature and volume of this power injection are dictated by adherence to grid codes. For instance, many power system operators mandate the provision of exclusively

positive sequence reactive current during fault occurrences, while typically omitting specifications for injecting positive active current. The underlying rationale for injecting reactive current revolves around its role in offering voltage support to the grid and aiding in the maintenance of grid stability, a principle discussed in detail in [11]. To delve deeper into the operational dynamics of voltage support during grid faults, Fig. 2 illustrates examples of grid code requirements across the aforementioned countries where ΔV is the difference between the nominal value of the voltage and the measured value at the output of the GCI. The parameter k depicted in Fig. 2 signifies the scaling factor or gain utilized for adjusting the magnitude of reactive current injection during fault occurrences, thereby ensuring adherence to grid codes. The reactive current support settings (I_q) across the mentioned

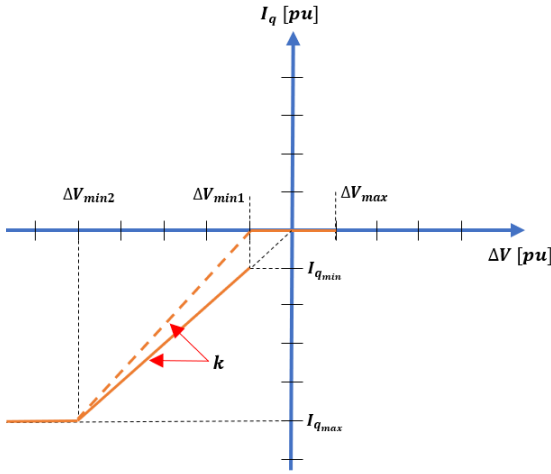


Fig. 2. Reactive current to be injected during a fault

countries have been extensively detailed and outlined in [12], [7] and [13], as depicted in Table II.

TABLE II
REACTIVE CURRENT SUPPORT SETTINGS

Country	$\Delta V_{\min 1}$ [pu]	$I_{q_{\min}}$ [pu]	$\Delta V_{\min 2}$ [pu]	$I_{q_{\max}}$ [pu]	ΔV_{\max} [pu]	k
Germany	-0.1	-0.2	-0.5	-1	0.1	2
Denmark	-0.1	0	-0.5	-1	0.1	2.5
China	-0.1	0	-0.8	-1.05	0.1	1.5
South Africa	-0.1	0	-0.5	-1	0.1	2.5

Notably, within French medium voltage operations, there exists no compulsory regulation regarding current injection during faults in the feeder.

III. INVERTER CONTROL

In this project, Pulse Width Modulation (PWM) is selected to govern the states of inverter switches, a choice widely embraced in the industry, as evidenced in various publications such as [14] and [15]. PWM control offers precise management of the inverter output voltage and frequency, effectively

curbing harmonic distortions in the waveform. This precise control is essential for adhering to network standards and regulations that set limits on harmonic presence, ensuring the inverter compliance with specified performance criteria. Fig. 3 presents an example of a single-line diagram of a power plant connected to the medium-voltage grid. It highlights the various components constituting the power plant, such as the inverter, filter, measurements, control parts and the decoupling protection. The decoupling protection uses voltages to detect faults in the MV feeder when it is connected to the grid, with the voltage set to 85% and a delay of 1.5 seconds for power plants with an installed power equal to or greater than 1 MW, as outlined in [10]. Such a delay is sufficiently long for the power plant to contribute to the fault if it is allowed to. During

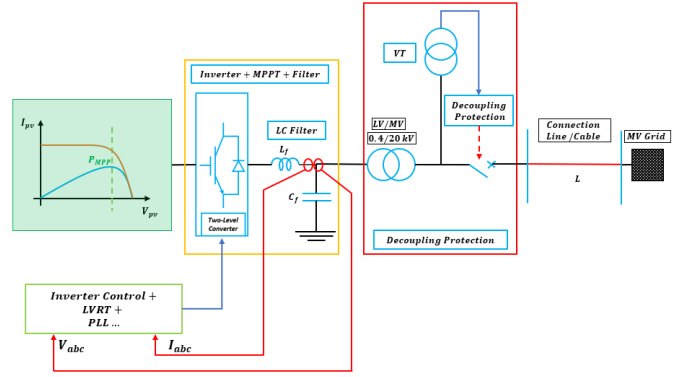


Fig. 3. Single line diagram of a RE power plant connected to the MV grid

fault occurrences, the fault detector block triggers a signal to bypass the PQ control loop. Consequently, the inverter injects current in accordance with grid code requirements, with these currents following (1).

$$I_{\text{inv}} = \begin{cases} I_{\text{PQ}}, & \text{if } U_p > 0.85[\text{pu}] \\ I_q = k \cdot \frac{\Delta U}{U_n}, & \text{if } U_p \leq 0.85[\text{pu}] \\ I_d = \min \left(\frac{P_{\text{ref}}}{1.5 \cdot V_d}, \sqrt{I_{\text{max}}^2 - I_q^2} \right) & \end{cases} \quad (1)$$

Where:

- I_{inv} : Injected current by the inverter.
- I_{PQ} : Injected current during normal operating conditions.
- P_{ref} : Pre-fault active power.
- I_d : Positive sequence active current injected during fault conditions.
- V_d : Positive sequence d-axis voltage during fault conditions.
- I_q : Positive sequence reactive current injected during fault conditions.
- I_{max} : The maximum current of the inverter is generally between 1.1 and 1.2 [pu], according to [16] and [17]. In our case, this current is set to 1.25 [pu]. Our studies showed that the impact of the GCI on the currents measured by the OC relay is higher when the maximum current of the inverter is increased. Therefore, at 1.1 [pu], we will have slightly less impact.

Fig. 4 depicts the control arrangement of the inverter for both normal and abnormal operating conditions. The reactive current to be injected during fault conditions depends on the factor k and the voltage sag, whereas for the active current (if allowed), the inverter will try to maintain the reference pre-fault power. If the voltage sag is significant, the inverter's active current will saturate at its maximum without reaching the reference power (see (1)).

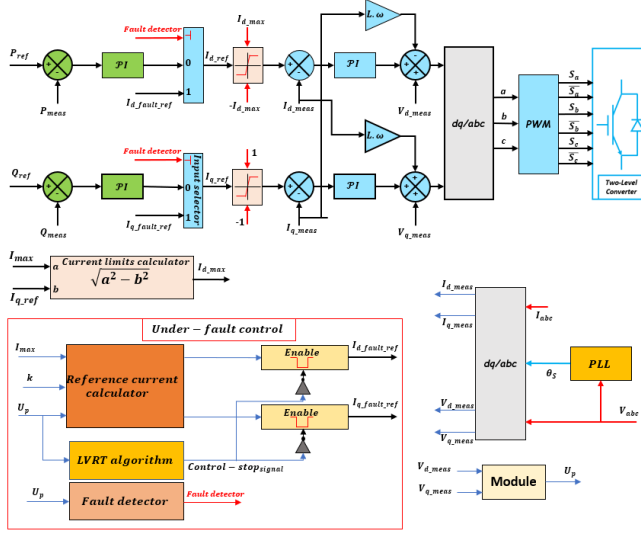


Fig. 4. Control scheme of the inverter

IV. CASE UNDER STUDY

To evaluate the impact of incorporating renewable energy-based static converters on phase-to-phase faults, we have constructed a simulation grid using Simulink. The scenario under analysis involves a substation within the medium voltage grid of France, characterized by a minimum short-circuit power of 100 MVA as depicted in Fig. 5. This setup includes

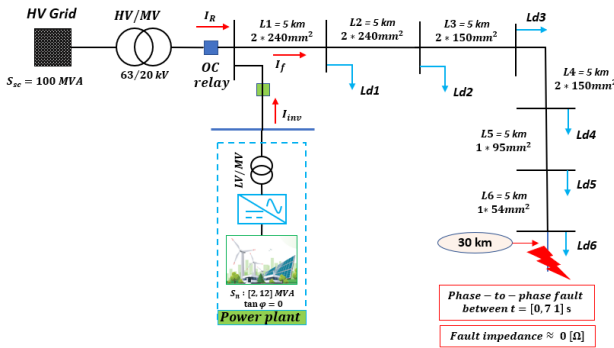


Fig. 5. Case under study

a high voltage to medium voltage transformer rated at 36 MVA, a 30 km cable, a power plant with a capacity ranging from 2 to 12 MVA, and six loads, all operating at a power factor ($\tan \varphi = 0$) under normal conditions. The PLL used here is a dual second Order generalized integrator (DSOGI),

this PLL allows for more effective tracking of grid voltage frequency changes and phase jumps as demonstrated in [18]. The deliberate placement of the plant at the beginning of the feeder anticipates that this configuration will yield the most challenging scenario. Our goal is to investigate the inverter's impact on the currents measured at the feeder's origin (I_{F_US}) when a phase-to-phase (B-C) bolted fault occurs 30 km away from the substation. To improve clarity and ease of interpretation, we have introduced a parameter designated as α . This parameter represents the disparity between the current readings obtained by the substation with and without the GCI, as outlined in (2).

$$\alpha = \left(\frac{I_{R_{w-GCI}} - I_{R_{wo-GCI}}}{I_{R_{wo-GCI}}} \right) \times 100 \quad (2)$$

Where:

- α : The blinding factor.
- $I_{R_{w-GCI}}$: Upstream current measured in the presence of the GCI.
- $I_{R_{wo-GCI}}$: Upstream current measured without the GCI.

The α factor provides a numerical gauge of the GCI's impact on the substation's current, also acting as a normalization factor.

A. Study Case Conditions

- The load is negligible, as evidenced by our studies indicating that the currents supplied by the substation under this condition are lower compared to the currents when there is a load. This is because the substation at this level supplies both the fault current and the load current.
- The voltage at the substation bus-bar is maintained at 1 [pu].
- During normal operating conditions, the inverter only supplies active power, the reactive power is set to zero.
- The inverter has a maximum power output of 12 [MVA].

These conditions define the parameters under which our study case operates.

B. Dynamic simulation results

The case study is carried out using Simulink (Matlab), demonstrating the practical application of theoretical principles. In Fig. 6 and Fig. 7, the active and reactive powers injected by the GCI during a phase-to-phase bolted fault at the line's end are depicted for two specified scenarios, as a function of the installed power of the GCI. It is evident that the reactive power injected for the case where $k = 0$ is zero, which aligns with our expectations. Upon closer examination of the active power given in Fig. 6, when $k = 2$, the GCI injects slightly more power than the case where $k = 0$ and it reaches its maximum active power (1 pu) when the GCI installed power is higher or equal to 6 MVA. At first glance, this may seem counterintuitive, as one might expect more active power injection for $k = 0$, since all the current is injected as active power and the current limiter is set to the maximum current (I_{max}). Conversely, for $k = 2$, a portion

of that current is injected as reactive power (see Fig. 7), and the remainder as active power. The reactive power injection is intended to improve the voltage plan and consequently the active power injection (and the overall stability of the grid). In this case, the limits of the current limiter for active current are lower than the maximum current of the inverter, since the priority was set to deliver reactive current. To address this apparent discrepancy, let us examine the voltage profiles, as the power delivered depends on the current of the inverter and the voltage at its terminals as it is given by (3).

$$P_{GCI} = \frac{3}{2} \cdot I_d \cdot U_{p_GCI} \quad Q_{GCI} = -\frac{3}{2} \cdot I_q \cdot U_{p_GCI} \quad (3)$$

The Fig. 8 below highlights the voltages across the GCI for

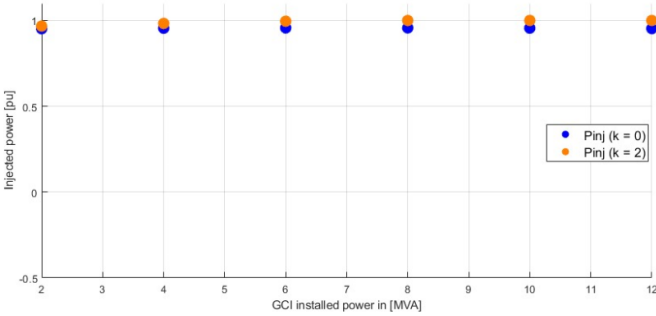


Fig. 6. Active power injected by the GCI during the fault

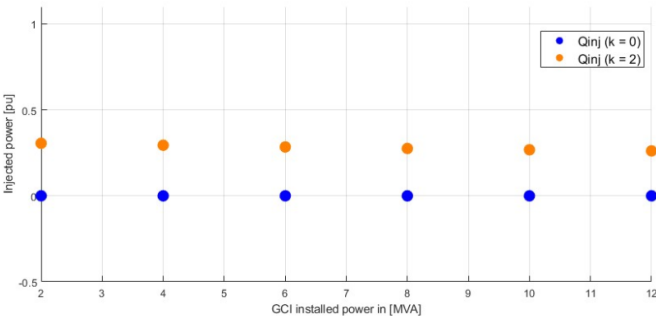


Fig. 7. Reactive power injected by the GCI during the fault

both cases ($k = 0$ and $k = 2$). It can be seen that when $k = 0$, the voltage profile across the GCI is almost constant with respect to the installed power. At this stage, the GCI will try to maintain its reference active power by injecting more current. Unfortunately, it reaches current saturation (I_{max}) without achieving the reference power. However, for $k = 2$, the voltages are improved, and the improvement is proportional to the installed power of the GCI. The amount of improvement ranges between 5 to 8%. This case can be split into two subcases. The first one is when the installed power is less than 6 MVA; in this subcase, the improvement in voltage is not enough, and the GCI reaches current saturation, failing to maintain the reference active power. Whereas for the second subcase, when the installed power of the GCI is higher or equal to 6 MVA, the voltage improvement is sufficient to

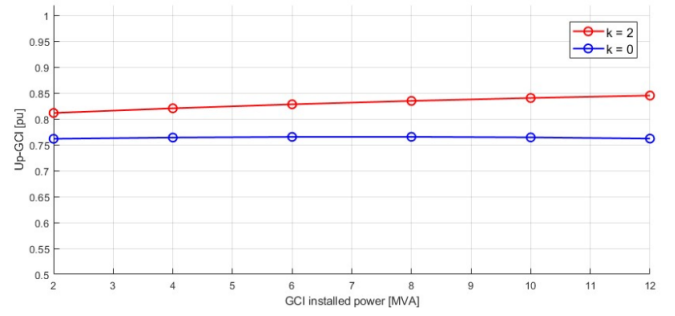


Fig. 8. Positive sequence voltage across the GCI

guarantee the reference active power. Now, let us return to the origin of the difference between the voltage profiles. The disparity in voltages between the two cases is directly linked to the injected reactive power. This reactive power supports and elevates the voltage across the inverter and the grid. The primary objective of injecting reactive power during a fault is to boost grid voltages and, consequently, improve overall grid stability (see Fig. 8).

Now, regarding the currents, Fig. 9 illustrates the maximum blinding factor between the two phases under fault (B-C) affecting the substation due to GCI contributions.

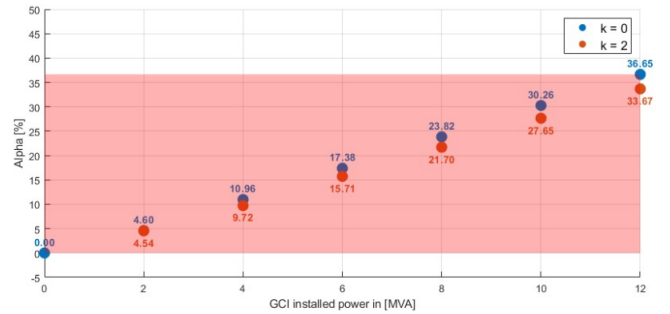


Fig. 9. Blinding effect caused by the GCI

The shaded area, representing a positive blinding factor, indicates that the currents recorded by the relay at the feeder's head in the presence of the GCI are lower than those measured without the GCI. A closer examination reveals a direct correlation between the blinding factor and the installed power in the GCI, as the substation solely provides the complement. A slight difference becomes apparent when comparing scenarios with $k = 0$ and $k = 2$. It is important to note that the blinding factor depends also on the impedance of the feeder. Now coming back to relay setting, Enedis set the relay's tripping current according to (4). The upper 20% margin is taken to cover measurement errors, whereas the lower 30% margin is taken to avoid tripping in normal operating conditions. If the RE sources-based static converters contribute to the fault, the upper limit should be reduced by an amount which depends on the installed power; otherwise, the relay may fail to detect the fault.

$$1.3 \cdot I_{\text{load}} \leq I_S \leq 0.8 \cdot I_{\text{sc2p}} \quad (4)$$

Where:

- I_S is the setting point of the overcurrent relay.
- I_{load} is the nominal load current measured at the head of the feeder in normal operating conditions.
- I_{sc2p} is the phase-to-phase fault current given by the standard IEC 60909 (this standard does not take into consideration the contribution of the GCI to the fault.)

V. CONCLUSION

During this project, we extensively explored how the integration of GCIs and their control strategies affects relay performance in phase-to-phase faults. Our research revealed a significant decline in relay-measured currents, which we attribute to the GCIs role in fault situations. This decrease is directly proportional to the installed power of the GCI. It is crucial to consider the presence of GCIs when setting up relays. This can be accomplished by adding a safety margin to current settings or adopting alternative detection methods. Neglecting to do this may lead to insufficient relay triggering.

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