



Grid-Forming and Grid-Following Inverter Fault Current Contribution

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1 Executive Summary

The increasing penetration of inverter-based resources (IBRs) in modern power systems poses significant challenges for traditional protection systems, which were designed for synchronous generators that have predictable fault current behaviour. Unlike synchronous generators, IBRs produce fault currents that are often lower in magnitude, more variable, and influenced by fast electronic controls. These characteristics could disrupt the operation of traditional protective relays, potentially leading to misoperations and system security concerns.

This report outlines the relay operating principles and IBR responses leading to misoperation of the relay. It provides a broader discussion on relevant operating principles of protection systems and IBRs, determining the overall response to a fault. Also, the report surveys international incidents of relay misoperation and analyses the technical and operational factors contributing to these events. It evaluates the impact of both grid-following (GFL) and grid-forming (GFM) inverters on fault current attributes and relay performance, including current magnitude, phase angle, sequence components, and harmonic distortion. A list of technical and regulatory recommendations is presented to improve the overall adequacy of the modelling and performance of the power system protection system in IBR-rich power systems.

- Through a literature survey, it has been identified that traditional protection systems are not well-suited to the dynamic and limited fault current contributions from IBRs. Some international incidents of relay misoperation and their analysis demonstrate the limitation of GFL inverters in providing protection-quality fault current. GFM inverters offer improved stability and impedance control but still face limitations in fault current magnitude and consistency. Relay types most affected include distance and directional relays. Real-world incidents demonstrate the need for improved modelling, standards, and relay adaptability. There are some limitations of traditional fault current calculation methods, and it is recommended to update simulation tools to reflect IBR behaviour during the fault, in a way that better reflects the nonlinear fault response of IBRs (or use simulation tools with already enhanced capabilities). It requires iterative solution methods and manufacturer-provided data to simulate fault behaviour accurately.
- It is crucial to enhance modelling and simulation practices and to use electromagnetic transient (EMT) simulations to study fault current variability and impedance changes, and to validate relay coordination. Integrated system studies should simulate both weak and strong grid conditions with varying ratios of GFM and GFL inverters. These studies should also consider the impact of synchronous generator retirement on voltage dips and relay behaviour. Additionally, validating relay models against field data using hardware-in-the-loop (HIL) testing is desirable to ensure real-world reliability.
- On the regulatory front, it is suggested to revise performance standards to define new thresholds for fault current magnitude, negative-sequence component, phase angle stability, and harmonic limits. These thresholds could be formalised into access standards or incentivised through system services. It also recommends adopting requirements similar to IEEE Std 2800-2022 for negative-sequence current injection during unbalanced faults, which would improve relay compatibility and fault detection (further investigation is required to assess the suitability of IEEE Std 2800-2022 for GFM inverters). Additionally, the report proposes conducting surveys

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with transmission network service providers (TNSPs) and original equipment manufacturers (OEMs) to identify relay types most susceptible to IBR fault characteristics and to assess the capabilities and limitations of GFM and GFL inverters in providing protection-quality fault current.

In summary, the report provides a detailed discussion of how GFL and GFM inverters impact fault current behaviour and relay performance, supported by international case studies and technical evaluations. The recommendations range from improved modelling practices to regulatory reforms and industry collaboration. The report offers a clear roadmap for enhancing the understanding of IBR fault current behaviour and its impact on protection systems. A list of proposed success criteria for inverter fault-current behaviour, framed to support protection performance and comparability across OEMs, is outlined for the industry to discuss and debate, guiding future access standards and simulation studies to ensure reliable protection operation in IBR-rich power systems.

2 Introduction

The increasing penetration of inverter-based resources (IBRs) in modern power systems poses significant challenges for traditional protection systems. As the grid transforms to integrate more IBRs, the dynamics of fault currents, sequence components, and harmonic distortions differ significantly from conventional synchronous machines. This document surveys international practical experiences associated with misoperation of protective relays under high IBR penetration and explores technical and operational issues arising from this transition. Both grid-following (GFL) and grid-forming (GFM) inverters are considered.

The agreed scope of work includes the following:

- Survey of international practical experiences associated with misoperation of protective relays under high penetration of inverter-based resources
 - Discuss the relay operating principles resulting in misoperation
 - Discuss aspects of IBR response contributing to misoperation
 - Actions taken since the incident (if any) and relevance to the NEM
- Broader discussion on relevant operating principles of protection systems and inverter-based resources, determining the overall response to a fault
 - Differences between inverter-based resources and synchronous machines from the perspective of impact on protective relays
 - Differences between GFM and GFL from the perspective of impact on protective relays
 - Decompose the fault current into several distinct attributes and discuss the impact of each on potential relay misoperation
 - These include current magnitude, phase angle, sequence and waveform, including the level of harmonics, inter-harmonics and voltage unbalance and impact on correct operation of protection systems.
 - Discuss the impact of factors other than the inverter fault current, e.g. network topology, generation mix, nearby plant and fault type, on the operation of protection systems
 - Any other driving/compounding conditions or types of relays that could result in misoperation under high IBR penetration scenarios
- Equipment survey
 - Assumptions:
 - TNSPs and OEMs are willing and available to participate. They will provide open, timely and accurate responses to the survey and any subsequent discussions. AEMO will assist in arranging and facilitating these communications and/or sessions.
 - Etik Energy will focus on digital and numerical relays. Electromechanical relays have been progressively replaced, are in the minority and are expected to retire over the coming years fully. There is often not sufficient information available on the algorithm used by the vendor, and a model of such relays cannot be developed with high confidence/accuracy for the next stage.
 - TNSP relay survey

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- Prepare a questionnaire/table for completion by TNSPs
- Determine how universal a susceptibility various relay makes might have to particular fault current attributes discussed above
- Shortlist relay types/makes of most importance for the modelling stage
- GFM OEM survey
 - Prepare a questionnaire/table for completion by GFM OEMs
 - (This could potentially be combined with the OEM survey, which is to be conducted for AEMO's GFM rule change, subject to AEMO's approval.)
 - Describe the limitations of GFM inverters in providing protection-quality levels of fault current.
 - Discuss whether the particular attribute(s) being lacked apply to most or a few OEMs
- GFL OEM survey
 - Noting the time criticality of this project, and to avoid further delays by OEMs in responding to the GFM survey above, this part will be completed based on Etik Energy's in-house knowledge
 - Discuss whether the particular attribute(s) being lacked apply to most or a few OEMs
 - Discuss any particular aspects where GFL may be inferior to GFM from the perspective of protection-quality fault current
- Suggest pathways to confirm further aggregated relay and GFM inverter response via power system modelling
 - New/modified performance standards for all inverters
 - New/modified performance standards for grid-forming inverters
 - Assess the implications of each, including
 - Inability to meet other aspects of performance standards
 - Significant extra cost to deliver protection-quality fault current
 - Impact on the lifetime of the inverter or associated prime mover
 - Determine if a threshold for the maximum percentage of online GFM can be developed, where the contribution can be safely considered for minimum fault current calculation
 - Determine if a threshold for the maximum amount of fault current from each GFM can be developed, where the contribution can be safely considered for the minimum fault current calculation
 - Any other changes to be implemented on the broader network to increase the effectiveness of GFM's protection-quality fault level
 - Interactions between performance standards and system services
- Improved IBR fault current calculation methodology

Assumption: No simulations are required to complete this portion of the work.

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- The importance of accurate fault current calculations as a prerequisite for future use in minimum system strength requirements
- Phasor-domain transient tools' deficiencies
- EMT tools' deficiencies
- Improved fault current calculation methodology
- Recommendations
 - Definition of success criteria
 - Definition of 'near protection quality fault response'
 - Modelling for the next stage
 - System to be modelled
 - Generation technology and type to be modelled
 - EMT Studies to be conducted
 - Testing
 - Secondary injection of EMT results into real-time simulation and associated setup and methodology
 - Any other gaps regarding the performance of protection systems and sufficient confidence building, which may not be possible to address by just looking at grid-following and grid-forming inverters

3 Differences Between IBRs and Synchronous Machines impacting relay performance

Table 1 highlights the key differences between synchronous machines and IBRs that are relevant for understanding their impact on protection systems. A more detailed analysis of how each attribute affects the performance of specific relay types is provided in Section 3.

Table 1 Key differences between machines and IBRs relevant to assessing the impact on protection systems

Attribute	Synchronous Machines	IBRs
Fault Current Magnitude	High (up to 3 p.u.) (considered at 10 ms or later after the fault occurrence)	Limited (1.0 - 1.5 p.u.), variable depending on control strategy (GFL vs. GFM).
Negative-/Zero-Sequence	Significant and inherent contribution during unbalanced faults.	<ul style="list-style-type: none"> Minimal or negligible by default. Can be provided by the control system, but the impact on other aspects of the response, requiring a portion of the available current, must be considered.
Phase angle	Relatively constant phase angle during faults.	Variable phase angle during faults.
Harmonics	Minimal	High harmonic and interharmonic content during faults.
Dynamic Behaviour	Governed by physical inertia and excitation systems	Determined by fast electronic controls, leading to rapid adjustments in current, phase angle, and impedance.
Fault Duration	Determined by their critical clearing time	Extended fault durations occur due to fault ride-through requirements, as IBRs are not susceptible to loss of synchronism like synchronous generators. Consequently, the concept of critical clearing time is less restrictive for IBRs. This difference impacts the coordination between primary and backup protection schemes.
Impedance Variability	Relatively constant impedance during faults.	Dynamic and controlled impedance responses.
Harmonic Filtering for Protection Systems	Not typically required.	Advanced harmonic filtering is needed to mitigate the effects of high-frequency components on protection systems.
Relay Adaptability	Relays calibrated for predictable synchronous generator behaviour.	Relays may require adaptive algorithms to handle dynamic fault characteristics and control-induced variability of IBRs.

4 Relay Operating Principles and IBR Responses Leading to Relay Misoperation

4.1 Principles of Relay Operation

Protective relays detect and isolate faults based on current, voltage, and impedance measurements. Relays in conventional systems rely on predictable fault characteristics, including fault current magnitude, phase angle, and sequence components, provided by synchronous generators. The shift to IBRs introduces unique attributes that disrupt relay functionality.

4.1.1 Distance Protection

4.1.1.1 Basic principles

Many power systems apply MHO or Quadrilateral (Quad) characteristics in distance relays for transmission line protection applications. A distance relay operates by calculating the impedance ($Z = V/I$) between the relay location and the fault. The relay measures voltage and current to compute apparent impedance and triggers protection if the impedance falls within a predefined zone. Distance relays often monitor fault current levels as a secondary validation mechanism for impedance-based fault detection, where abnormal current magnitudes can further confirm fault conditions.

A widely used distance relay implementation is the polarised MHO relay, which operates on the principle of impedance measurement. The relay determines whether a fault is within its zone of protection by comparing the measured impedance to a pre-defined characteristic known as the "MHO circle." If the impedance falls within this characteristic and remains there for a minimum time, the relay trips to clear the fault.

4.1.1.2 Self-Polarised MHO Characteristics and IBR Influence

A self-polarised MHO characteristic is typically represented as a circle in the first quadrant of the R-X impedance plane, passing through the origin. The diameter of this circle represents the relay's reach or "line-of-sight", extending towards the transmission line being protected [1].

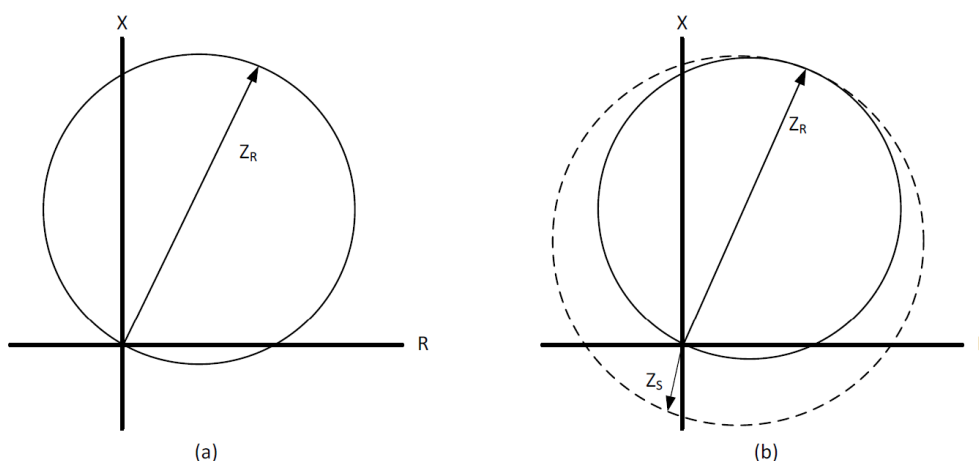


Figure 1 Positive sequence Polarised mho distance characteristics (a) without and (b) with dynamic expansion

However, the impact of large changes in source impedance behind the relay (such as from an IBR) is not immediately apparent in a self-polarised MHO characteristic. In low fault current conditions,

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the system behaves as a high-impedance source behind the relay for a forward fault, causing the MHO circle to expand dynamically, which may compromise protection reliability.

4.1.1.3 Voltage-Polarised MHO Characteristics and Dynamic Expansion

To address limitations of self-polarised MHO characteristics, voltage polarisation is often used in practice. A typical MHO relay uses positive sequence voltage polarisation to enhance coverage for faults close to the relay location or near the origin, where self-polarisation alone would not produce enough operating torque. Figure 1(b) illustrates this expanded characteristic, which is proportional to the source impedance behind the relay [1].

Dynamic variations in highly inductive source impedance (both magnitude and phase angle) behind the relay can cause the MHO characteristic to expand unpredictably, leading to either overreach or underreach. This is particularly problematic in systems with high IBR penetration as will be elaborated further in Section 4.3.3.

4.1.1.4 Polarisation in MHO Relays

Polarisation provides a reference signal to help the relay distinguish between forward and reverse faults. In MHO relays, this reference signal can be derived from:

- Voltage Polarisation: Uses voltage as a reference to determine the fault direction.
- Memory Polarisation: Stores pre-fault voltage as a reference to improve relay accuracy during transient conditions when system voltage is unstable.

4.1.2 Other impedance-based Relays

Several other widely used relays in power systems, such as out-of-step protection, power-swing-blocking (PSB), power-swing-tripping (PST), and synchronous generator loss-of-excitation protection, rely on consistent impedance calculations during faults with similar operating principles to those of distance protection.

In interconnected power systems, for protection schemes like PSB and OST, blinders (or blinders-based schemes) are commonly used, particularly in scenarios where the system needs to differentiate between fault conditions and normal operating conditions. For example, as shown in Figure 2, the two-blinder scheme, which operates by timing an impedance vector's movement across a set impedance range [2]. Timing begins when the vector crosses the outer blinder (RRO) and ends at the inner blinder (RRI). If the measured time exceeds the delta time setting, a power swing is detected.

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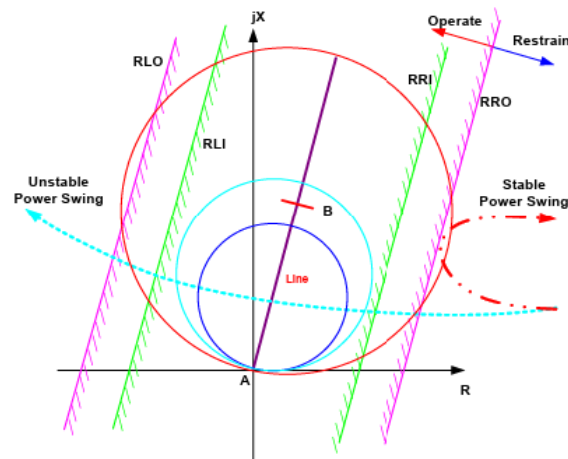


Figure 2 Two blinder scheme

Concentric distance relays are also used but might be more common in traditional schemes with high concentration of synchronous generators where simpler fault detection and discrimination are sufficient.

4.1.2.1 Operating principles [2] [3] [4]

- Out-of-Step Protection:
 - Detects swings in system stability caused by generator oscillations or sudden load changes. These relays rely on impedance trajectories to identify conditions where synchronous generators fall out of synchronism.
- Power-Swing-Blocking (PSB):
 - Prevents unnecessary tripping of relays during stable power swings not associated with faults. Transients and impedance fluctuations can mislead PSB algorithms. This may cause the relay to block valid trips for actual faults or fail to block trips for benign swings, resulting in miscoordination.
- Power-Swing-Tripping (PST):
 - PST triggers operation when power swings exceed pre-set stability thresholds to differentiate between stable and unstable swings. In synchronous generator-based systems, these thresholds are well-defined due to predictable inertia-driven oscillations. However, in IBR-dominated networks, power swings behave differently as IBRs lack inertia and rely on fast power control adjustments, leading to irregular impedance movements. This can obscure stability thresholds, causing premature or delayed tripping. Rapid power changes from IBRs may push impedance into tripping zones, even when the system is stable, while unconventional swing patterns may delay necessary tripping.
- Loss-of-Excitation Protection:
 - Monitors reactive power flow and impedance to detect loss of excitation in synchronous generators. The most widely used LOE relay is that with two offset $m\Omega$ relays, as it provides loss-of-excitation protection for any loading level. Both relays are set with an offset of $X' d / 2$ as shown in Figure 3 [3]. Experience has shown that these Zone 1 and Zone 2 settings are secure from stable swing encroachments over a wide range of system conditions.

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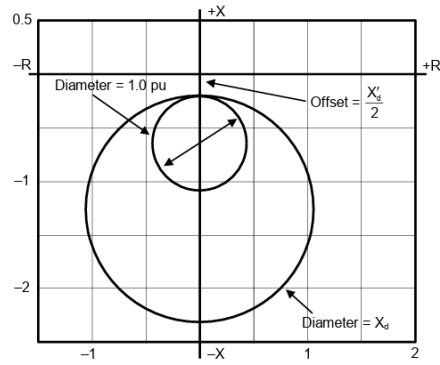


Figure 3 Two zone offset Mho characteristics of LOE relay

4.1.3 Differential Protection

Differential relays monitor current entering and leaving a protected zone, typically a transformer, bus, a generator¹ or a transmission line. A mismatch exceeding a set threshold triggers protection, indicating a fault within the zone as shown in Figure 4. While effective for detecting internal faults, differential relays may struggle with harmonic distortions and phase angle inconsistencies.

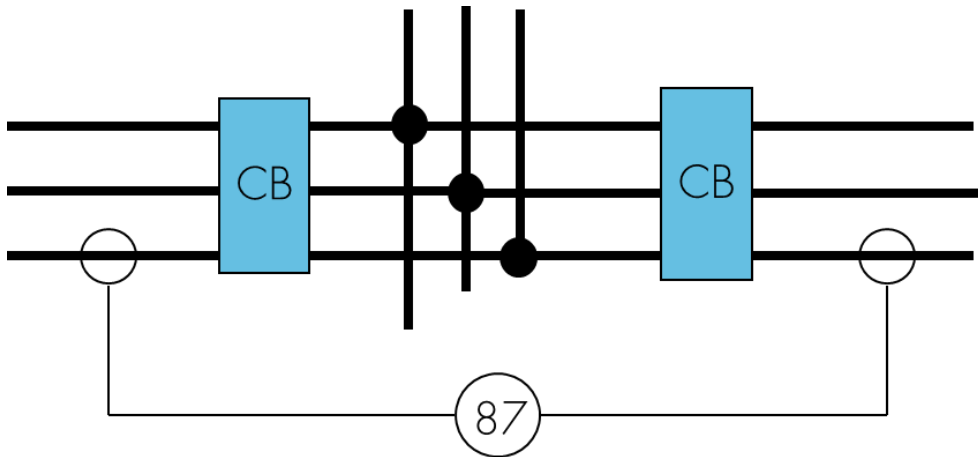


Figure 4 Basic operating principle of differential relays

To improve security, generator and transformer differential relays detect harmonic distortions to differentiate between genuine faults and transient disturbances such as transformer inrush, and to prevent misoperation under non-fault conditions. A key condition to prevent false tripping is when only one end of a transformer is energised. During energisation, the magnetising inrush current at the energised terminal can be significantly high, creating a substantial differential current even in the absence of a fault. If this differential current enters the relay's operating zone, the relay could mistakenly trip the transformer.

Such differential relays with harmonic restraint or blocking are sometimes used. The harmonic restraint method incorporates a restraint mechanism that prevents tripping if the harmonic content exceeds a specific level, utilising a harmonic restraint characteristic to distinguish between fault-

¹ In generator differential protection, the generator stator windings are the protected zone and Current transformers (CTs) are placed at two key locations:

- One set of CTs on the neutral side of the stator winding.
- One set of CTs on the terminal (line) side, where the generator connects to the system.

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induced differential currents and harmonics. This approach is frequently used in transformer protection to handle magnetising inrush currents. The harmonic blocking method detects harmonic components in the differential current and blocks relay operation when the harmonic content exceeds a set threshold. It assumes that high harmonic content is indicative of non-fault conditions, such as transformer inrush. A summary of key advantages and challenges for each approach is presented in Table 2.

Table 2 Differential Relay with Harmonic Restraint and Blocking

Feature	With Harmonic Restraint	With Harmonic Blocking
Response to Harmonics	Adjusts to harmonics without blocking.	Blocks the operation when harmonics exceed the set threshold.
False Trip Prevention	Moderate, depends on harmonic restraint settings.	High, effective in harmonic-rich environments.
Fault Detection Accuracy	High, provided harmonics are below the restraint level.	May fail to detect faults with high harmonic content.
Applications	Moderate harmonic systems (e.g., transformer energisation).	High harmonic systems (e.g., IBR-dominated grids).
Challenges	Requires precise harmonic detection algorithms; less effective in rapidly changing dynamics.	May block legitimate fault detection in cases where harmonics are part of the fault signature.
Suitability	Suitable for predictable harmonic environments.	Effective for unpredictable harmonic environments with significant distortion.

The following harmonic orders are typically used:

- 2nd/4th Harmonic Restraint
 - Purpose: Block differential tripping during magnetising inrush.
 - Principle: Inrush current contains pronounced even harmonics, primarily 2nd; 4th is often present at a lower level and improves security for some modern low-flux designs where 2nd can be marginal.
 - Implementation options:
 - 2nd-only threshold: Restrain when $H2/H1 \geq \sim 15\text{--}20\%$.
 - Composite even-harmonic: Restrain when $(H2 + k \cdot H4)/H1 \geq \text{threshold}$ (e.g., H2 threshold $\sim 12\text{--}15\%$ with H4 aiding at $\sim 6\text{--}10\%$; vendor-specific).
 - Limitations:
 - Modern transformers with low-flux designs may produce lower 2nd harmonic content, risking misoperation.
 - High short-circuit impedance units may have lower 2nd harmonic, requiring alternative techniques.
- 3rd Harmonic Restraint

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- Purpose: Occasionally used in addition to the 2nd harmonic for improved security.
- Principle: The 3rd harmonic is present in both inrush and overexcitation conditions, but is not as dominant as the 2nd harmonic. Triplen harmonics are often suppressed or redistributed (e.g., by delta windings), making the 3rd harmonic less reliable as a primary inrush discriminator.
- Usage: Some relays allow 3rd harmonic-based blocking or restraint to enhance security, but it is not universally applied.
- 5th Harmonic Bypass
 - Purpose: Detects overexcitation and allows differential protection to operate when the transformer is overexcited.
 - Principle: Overexcitation due to overvoltage (V/f ratio exceeding limits) generates significant 5th harmonic.
 - Implementation: Instead of restraining like a 2nd harmonic, the presence of high 5th harmonic content can bypass inrush blocking, allowing tripping for overexcitation-related faults.
- Practical use in modern relays
 - 2nd harmonic restraint: Almost always used for inrush detection.
 - 3rd harmonic restraint: Optional/usually off.
 - 4th harmonic restraint: enabled if available.
 - 5th harmonic bypass: Used to allow tripping under severe overexcitation conditions where traditional restraint could prevent necessary operation.

Differential protection schemes depend on synchronised current measurements from both ends of a protected zone. Achieving this synchronisation for line protection necessitates a robust and reliable telecommunication infrastructure, such as fibre optic cables or microwave links. These communication systems ensure low-latency and high-accuracy data exchange, which is critical for the relay to detect internal faults effectively.

However, deploying such infrastructure may not always be feasible in certain environments, including remote or rural areas, due to cost, physical access, or technological limitations. In these cases, alternative protection methods, like impedance-based or hybrid schemes, may need to supplement or replace differential protection. Adaptive algorithms can also mitigate some challenges, but they cannot fully address communication constraints.

4.1.4 Overcurrent Protection

Overcurrent relays operate when current exceeds a predefined limit, commonly used for fault detection in distribution networks. They are simple and reliable in traditional systems, but face challenges if a sufficient or relatively constant magnitude of fault current cannot be maintained.

Overcurrent relays may incorporate additional features to enhance their fault detection and decision-making capabilities:

- Directional Elements:

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- Some overcurrent relays include directional components to determine whether the fault is forward or reverse. This feature uses phase angle differences between voltage and current (also see below further information in Section 4.1.5).
- Voltage Supervision:
 - Overcurrent relays may use voltage levels to complement current measurements. Voltage-based supervision ensures the fault condition is valid before initiating a trip. Voltage supervision is essential for high-impedance faults. It enhances detection by ensuring the fault is valid, especially where current-based detection alone would fail
- Time Delays:
 - Adjustable time-delay settings allow the relay to coordinate with other protection devices, ensuring proper sequence in fault isolation.
- Sequence Component Analysis:
 - Advanced relays analyse negative- and zero-sequence currents to detect unbalanced faults, improving fault discrimination in scenarios like ground faults.
- Adaptive Thresholds:
 - Adaptive relays dynamically adjust pickup thresholds based on system conditions, making them suitable for environments with varying fault current magnitudes, such as IBR-dominated grids.

These features make modern overcurrent relays versatile and better suited for the evolving dynamics of power systems.

4.1.5 Directional Protection

Directional protection relays, usually embedded in the distance or over-current protection, determine the direction of fault current flow relative to the relay location. They utilise phase angle differences between voltage and current to ascertain whether the fault is forward or reverse. Some directional relays rely on negative-sequence currents for unbalanced faults, as these components are particularly indicative of fault direction. The absence of sufficient negative-sequence currents can compromise relay performance, particularly for relays designed for traditional synchronous generating systems.

4.1.6 Permissive overreach transfer trip (POTT)

POTT relays are a communication-assisted protection scheme designed for transmission line protection. They operate by comparing fault detection data between relays located at both ends of a transmission line. Key operating steps include:

- **Local Fault Detection:** Each relay monitors its zone for fault conditions using criteria such as impedance, current, and voltage.
- **Permission Signal Exchange:** When a relay detects a fault, it sends a permission signal to the relay at the opposite end of the line over a dedicated communication channel.
- **Mutual Agreement:** If both relays agree (i.e., detect a fault within the line section), the relays trip and isolate the line. If one relay does not detect a fault, no trip occurs, ensuring discrimination.

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Key advantages and challenges associated with POTT relays is summarised below:

- Advantages:
 - Enhanced fault discrimination by using communication to verify fault location.
 - Capability to clear faults quickly, improving system stability.
- Challenges:
 - **Communication Dependency:** POTT relays require high-speed, reliable communication systems. Any delay or failure in communication can lead to misoperation or a failure to clear the fault.

Note that a permissive underreach transfer trip (PUTT) relay also very occasionally exists. PUTT uses underreaching elements (typically Zone 1) to detect faults. Since underreaching elements do not extend beyond the protected line, faults detected are almost certainly within the line. The scheme relies on communication to ensure the remote end also permits tripping. However, PUTT is not widely used for the following reasons and, as such, was not considered in this work.

- Reliability and Sensitivity: PUTT requires faults to be detected within the underreaching zone at both ends before tripping, which can limit sensitivity for high-impedance faults.
- Speed vs. Selectivity Trade-off: Since underreaching elements operate faster (Zone 1 trips instantly), PUTT may not always require communication. If local underreach detects the fault, it can trip independently; therefore, the term “transfer trip” does not apply.
- Communication Use Case: While PUTT can improve selectivity, it is less common because many modern protection schemes use POTT due to its ability to detect faults beyond the immediate underreaching zone.

4.1.7 Fault Identification Logic (FID)

FID enhances traditional protection schemes by determining fault characteristics, including type, location, and severity. Its operation relies on analysing system quantities such as current, voltage, phase angles, and sequence components. FID utilises algorithms to distinguish between normal transients, symmetrical faults, and asymmetrical faults.

The following features may be used in FID.

- **Sequence Component Analysis:**
 - Analyses positive, negative, and zero-sequence currents and voltages to classify fault types (e.g., line-to-line or ground faults).
- **Harmonic and Transient Detection:**
 - Detects non-fundamental components in the signal, such as harmonics and interharmonics, to identify faults impacted by IBRs.
- **Phasor Angle Evaluation:**
 - Measures phase angle shifts between voltage and current to determine fault direction and severity.
- **Pattern Recognition and Machine Learning:**
 - Advanced FID systems employ machine learning to recognise fault patterns and adapt to dynamic system conditions.

Grid Forming and Grid Following Inverter Fault Current Contribution

For this discussion, the phase angle relationship between the negative- and zero-sequence current is used to identify the faulted-phase loop, which is one of the widely used methods. These angle ranges correspond to a known theoretical relation between the phase angle of negative- and zero-sequence components of phase-A current (I_{A2} and I_{A0}). The FID identifies the type of fault and faulted phases by determining which sector the measured phase angle falls within, as follows:

- 1) If the phase angle between I_{A2} and I_{A0} is $0^\circ \pm \text{margin}$ (the yellow sector), the fault type is either AG or phase-B and phase-C to ground (BCG), and the relay enables AG and phase B and phase C (BC) elements only. In this sector, the relay selects AG or BCG based on which element has the lowest calculated reach.
- 2) If I_{A2} lags I_{A0} by $120^\circ \pm \text{margin}$ (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.
- 3) If I_{A2} leads I_{A0} by $120^\circ (\pm \text{margin})$ (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 components. In a power system dominated by synchronous generators, this relation holds valid due to the inductive nature of the negative-sequence network and the impedances of the synchronous generator.

Due to delta-connected transformers, IBRs do not influence the zero-sequence network. Since FID operates based on the angle between negative-sequence and zero-sequence current phasors, the performance of FID is decided by the negative-sequence control of IBRs. The differences between IBR and synchronous generators may negatively impact the performance of FID.

4.1.8 Restricted Earth Fault (REF) Relay

A REF relay is a highly sensitive protection scheme designed to detect earth faults within a specific (restricted) zone of a power system, typically inside a transformer or generator winding.

The REF relay works by measuring the residual (zero-sequence) current in a transformer or generator winding. It compares the sum of phase currents (measured by phase CTs) with the neutral current (measured by a neutral CT). If an earth fault occurs within the protected zone, an imbalance in these currents appears, triggering the REF relay. If an earth fault occurs outside the protected zone, the phase and neutral currents remain balanced, and the relay does not trip.

The REF relay follows the principle:

$$I_{residual} = I_A + I_B + I_C - I_N$$

where I_A , I_B , I_C are the phase currents measured by phase CTs, and I_N is the neutral current measured by the neutral CT. Under normal conditions, $I_{residual} = 0$, meaning no fault is detected. If an internal earth fault occurs, $I_{residual} \neq 0$, causing the relay to trip.

REF protection is immune to external faults because the sum of the phase currents equals the neutral current for faults outside the protected zone. This ensures stability during external disturbances, unlike standard differential protection, which can be affected by through-fault conditions.

Grid Forming and Grid Following Inverter Fault Current Contribution

While REF protection may face challenges as IBR penetration increases, this aspect has been left out of this work since zero-sequence current is not a controlled quantity in IBRs and is instead more dependent on transformer earthing arrangements.

4.2 Impact of FRT Strategies on Protection Systems [1] [6] [7] [8]

- **Reduced Fault Current:** The reduced fault current provided by IBRs may not allow adequate fault clearance when using traditional overcurrent-based relay systems, leaving the fault uncleared for longer. It is important to note that the reduced fault current is not a result of the FRT response but rather a consequence of the inherent current limitations of the semiconductor switching devices used in IBRs. This is highlighted here to emphasise its potential role in prolonging fault duration (see the point below for further details).

Furthermore, reactive current injection during a fault can modify the depth of the voltage dip, potentially disrupting the operation of relays that depend on voltage supervision, such as overcurrent relays.

- **Prolonged Fault Duration:** FRT could prolong fault presence in the grid. To comply with grid codes, IBRs maintain connectivity through the fault duration, even if the fault persists. This contrasts with traditional synchronous generators, which may trip to isolate faults faster. Extended fault presence complicates the coordination between primary and backup relays, potentially delaying backup relay activation. This delay is exacerbated under low system strength conditions or systems with high impedance paths. It is important to note that an IBR has minimal sensitivity to fault duration, unlike a synchronous generator, which must trip or risk losing synchronism if the fault duration exceeds its critical clearing time. The challenge does not stem from the IBR's behaviour being inferior but rather from the fact that protection systems are traditionally designed with the capabilities and limitations of synchronous generators in mind. As discussed, these characteristics differ significantly from those of IBRs in several key aspects.
- **Prioritisation of positive-sequence fault current:** Most IBRs are designed to prioritise positive-sequence fault current as required by most grid codes and preferred by control system designers. The current limited nature of the IBR means that the negative-sequence current may be deprioritised, which in turn means that sufficient negative-sequence current may not be provided for the successful operation of relays relying on this quantity.

4.3 Unique IBR Attributes Contributing to Misoperation

4.3.1 Insufficient and Variable Fault Current Magnitude

- Fault current contributions vary with inverter control strategies (e.g., GFL vs. GFM).
- Fault current magnitude and variability from IBRs pose significant challenges for traditional protection systems. These characteristics differ considerably from synchronous generators, impacting relay performance.

4.3.1.1 Characteristics of Insufficient and Variable Fault Current Magnitude in IBRs

- **Reduced Magnitude:** Fault current contributions from IBRs are limited to 1.0 -1.5 p.u., significantly lower than the 2-3 p.u. typical of synchronous generators. This limitation is imposed by hardware protection and software-based control strategies to protect inverter components.

Grid Forming and Grid Following Inverter Fault Current Contribution

- Note that here, the IBR is assumed to be a solar PV system, a BESS, or a Type IV wind turbine. Type III wind turbines generally exhibit a larger peak; however, this is not significant from the perspective of protection system impact. The same applies to synchronous machines, where the initial peak rapidly declines to approximately 2–3 pu within the timeframe relevant to primary protection clearance times.
- Dynamic Control Influence: The magnitude of fault current depends on control strategies such as FRT control. GFL and GFM inverters differ in their fault current contributions due to varying control strategies.
- Time-Dependent Behaviour: IBR fault current magnitude varies dynamically during the fault, as control systems continuously adjust output based on system conditions.
- Note that Figure 5 assumes a constant fault current contribution from the IBR during the fault. However, in practice, this is not always the case. It often takes 40–80 ms for the fault current to reach 90% of its target value, with full settling occurring 1–2 cycles later. This is indicated in Figure 6 which compares RMS fault current profile in an IBR and a synchronous generator [9].

Practical experience has shown that an IBR may reach its maximum continuous current at around 80 ms but can then drop significantly, indicating potential high variability in the fault current contribution from the IBR. The high variability of IBR fault current will be discussed further in this document.

Fault Current Contribution: Synchronous Generator vs. IBR

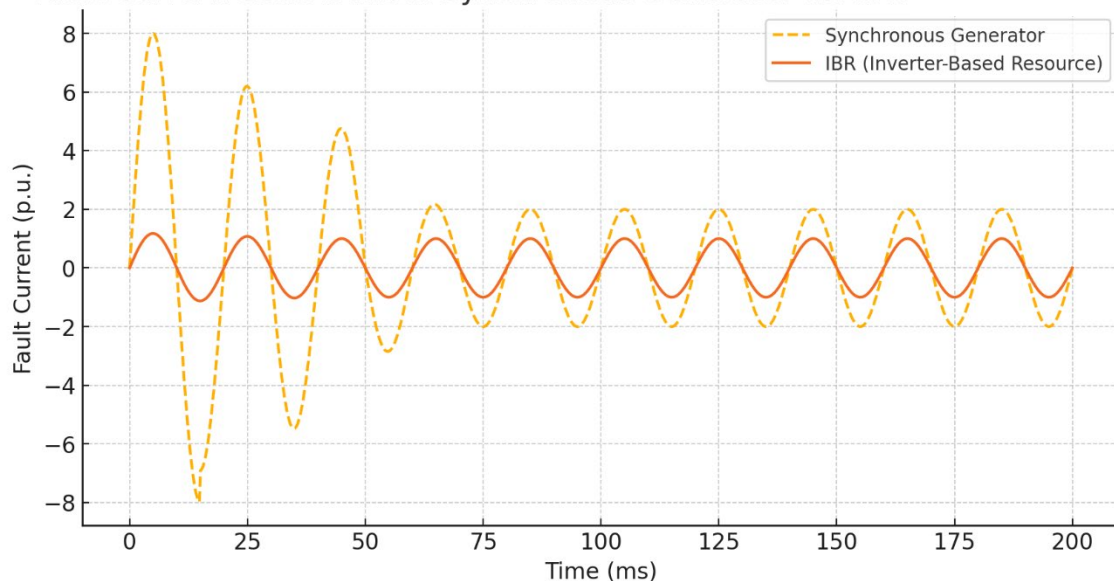


Figure 5 Idealised comparison of fault current waveform in IBRs and synchronous machines

Grid Forming and Grid Following Inverter Fault Current Contribution

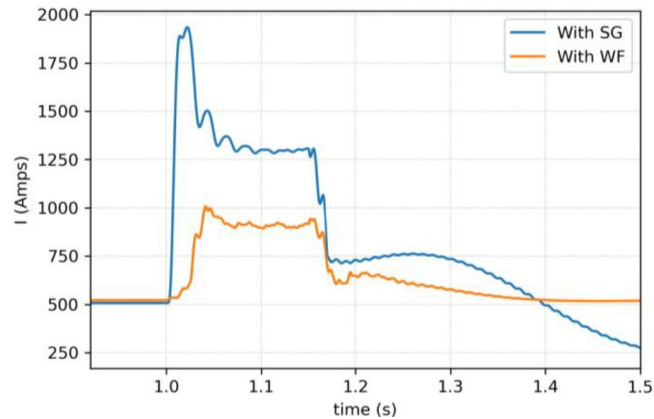


Figure 6 An example of RMS fault current in IBRs and synchronous machines [9] (This figure has been reproduced with permission from The IET, 2024)

4.3.1.2 Comparison with Synchronous Generators

- High Fault Current: synchronous generators deliver robust and predictable fault currents, enabling effective operation of overcurrent and impedance-based relays.
- Stable Response: synchronous generator responses to faults are governed by their inherent inertia and excitation systems, resulting in a consistent fault current magnitude.
- Limited Variability: Unlike IBRs, synchronous generator fault current characteristics are largely independent of time (besides the DC component decay, which can be readily calculated) and less susceptible to dynamic changes.

4.3.1.3 Implications for Protection Relays:

4.3.1.3.1 Overcurrent Relays

- Insufficient fault current may fail to trigger overcurrent relays, particularly those designed with high pickup thresholds for synchronous generator systems.
- Variations in fault current magnitudes complicate relay coordination, potentially causing delayed or missed tripping.

4.3.1.3.2 Distance Relays

- Reduced fault current impacts apparent impedance calculations, leading to underreach or overreach scenarios.
- Dynamic variations in fault current magnitude during transient events distort impedance trajectories, resulting in misoperation.
- A critical challenge in distance protection is that relay operation is typically supervised by a minimum phase current threshold. If an IBR's output current drops below this threshold before the relay completes its operating time, the relay fails to trip, leading to a potential protection gap. This is particularly problematic in low-generation conditions, where an IBR may have few units online and operating at low capacity before the fault. As a result, the lack of sufficient supervising current poses a significant risk to distance relay reliability in IBR-connected systems.

4.3.1.3.3 Directional Relays

- Fluctuations in fault currents disrupt phase angle measurements, leading to incorrect directional fault detection.

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4.3.1.4 Mitigation Strategies

The mitigation strategies outlined here and in other sections detail actions that can be undertaken by various industry stakeholders, including AEMO, TNSPs, and relay manufacturers. For instance, implementing adaptive relay settings would require initiative from manufacturers. In Section 6, our recommendations primarily focus on actions that AEMO can lead; however, the broader strategies discussed in each "Mitigation Strategies" section aim to provide a view of additional possibilities across the industry.

- Adaptive Relay Settings:
 - Configure overcurrent relays with lower pickup thresholds and dynamic adjustment capabilities to account for IBR-specific fault current characteristics.
- Hybrid Protection Schemes:
 - Combine impedance-based methods with differential or directional elements to improve fault detection under low fault current conditions.
- Enhanced Modelling and Testing:
 - Use electromagnetic transient (EMT) simulations to study fault current variability and ensure relay coordination is robust.
- Enhanced Performance for IBR Fault Current Contribution:
 - Revise access standards or define system services to specify a higher and more constant minimum fault current contributions from IBRs where possible.
 - Currently the maximum fault current contribution does not need to exceed above the maximum continuous current, i.e. 100%.

4.3.2 Insufficient and variable negative-sequence component [1] [10] [11] [12]

- Protective relays often rely on negative-sequence or zero-sequence currents to detect unbalanced faults. Negative-sequence currents are typically preferred because they provide more accurate fault localisation and are less affected by grounding configurations. However, in systems dominated by IBRs, both components are minimal, leading to challenges in fault detection. In applications where grounding plays a significant role, zero-sequence current-based relays may have an advantage but still face limitations due to IBRs' controlled fault response.
- This attribute poses unique challenges to protection systems that rely on negative-sequence current for fault detection, particularly during unbalanced fault conditions.

4.3.2.1 Characteristics of Negative-sequence Current in IBRs

- Low Magnitude: IBRs are generally designed to limit negative-sequence components such that the positive-sequence component can be prioritised.

Reference [1] provides estimates of the current through an inverter supplying negative sequence current during a close-in line-to-line fault on a transmission line. This example demonstrates that at least one phase of the inverter reaches a 120% current limit, which consequently restricts the negative sequence current injection during the fault. Additionally, the figure shows that if the IBR is not required to inject pre-fault load current during the fault, the negative sequence current injection could increase to approximately 60%. This example highlights that even when negative sequence current injection is mandated, its magnitude

Grid Forming and Grid Following Inverter Fault Current Contribution

remains constrained, as the vector sum of load current (if present), positive sequence reactive current, and negative sequence reactive current cannot exceed the IBR's current limit.

Reference [1] also presents fault current infeed from a solar farm as measured by the respective relay during a real single-phase-to-ground fault. The response shown in this reference does not resemble that of a traditional single-phase-to-ground fault due to the limited supply of negative sequence current from the solar generation facility. The negative sequence contribution was approximately 21% of the positive sequence current and 24% of the zero-sequence current, indicating that the inverters were actively limiting their negative sequence current injection in response to the fault.

Figure 7 presents the simulated fault current characteristics of a Type III-based wind farm during a double-phase-to-ground fault. In addition to the low magnitude of negative sequence current, significant variability in both positive and negative sequence currents is evident throughout the fault duration [12].

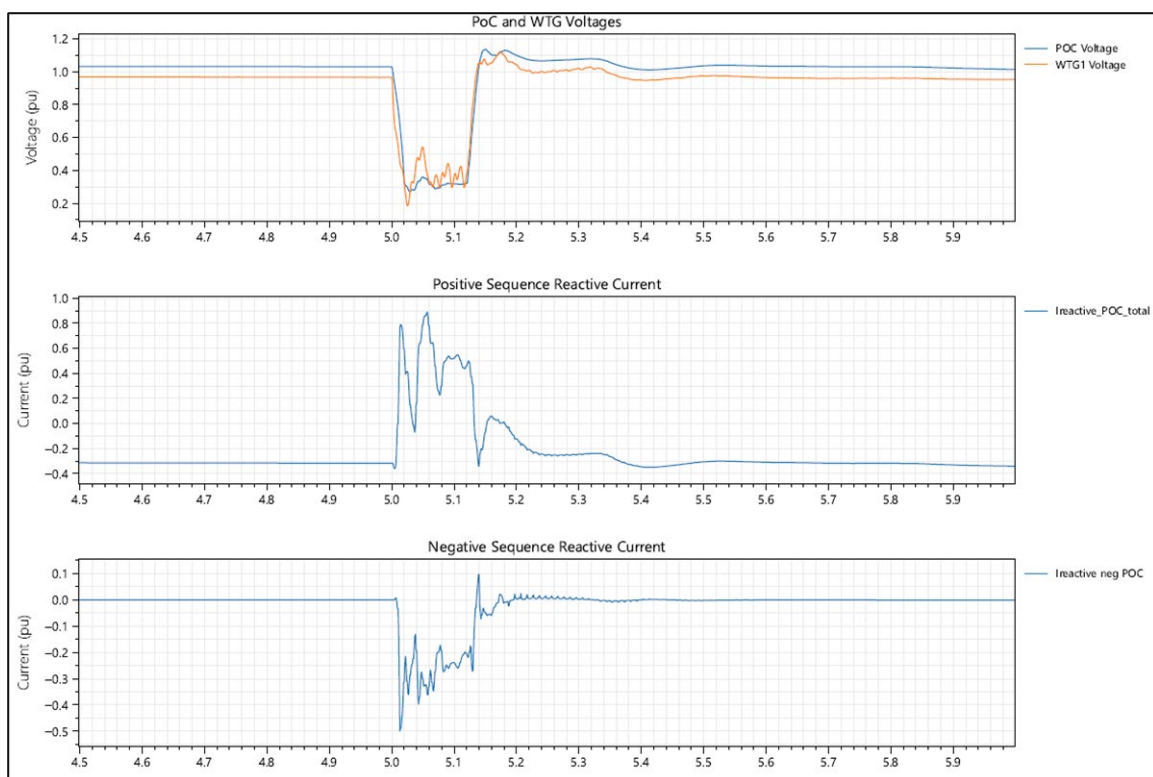
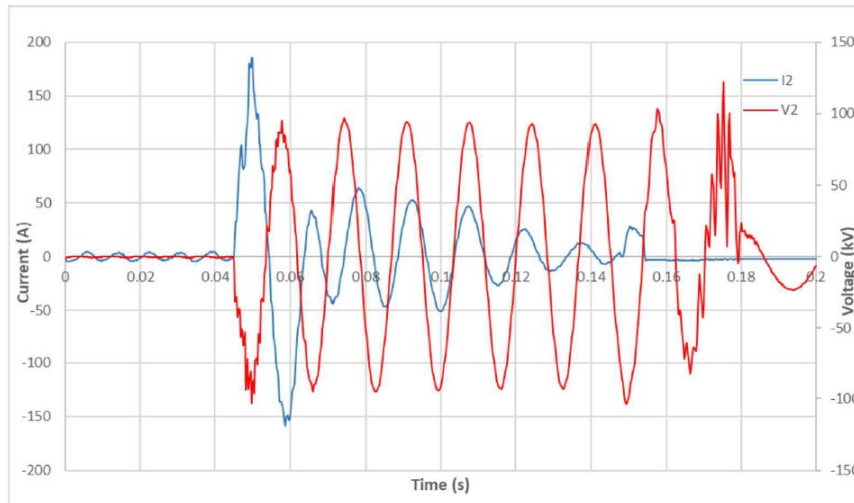


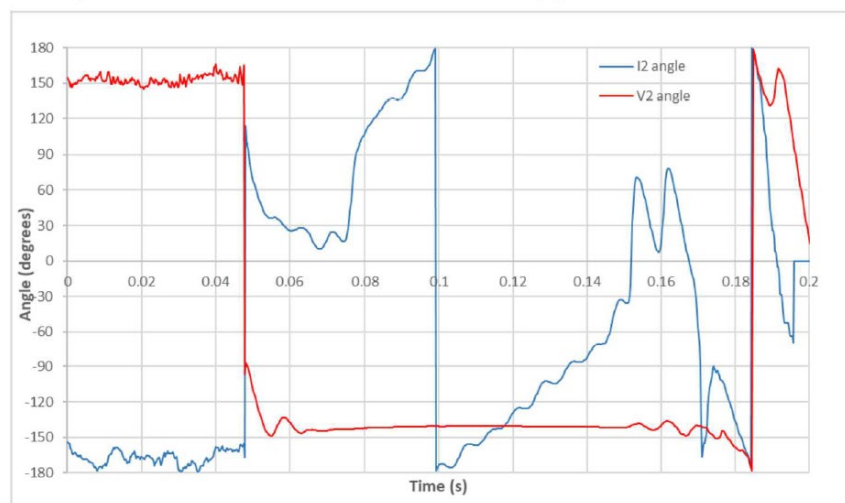
Figure 7 Negative-sequence behaviour of Type III wind farm

- Dynamic Control Response: IBRs modulate their output based on control strategies, leading to variations in the negative-sequence current during the fault's duration.
- Several practical IBRs have been reported where the frequency of the positive- and negative-sequence currents injected by the IBR differs from that of their respective terminal voltages. For instance, Figure 8(a) illustrates that the frequency of the unfiltered negative-sequence current (blue) is noticeably different from that of the unfiltered negative-sequence voltage (red) [11]. Further highlighting this lack of coherence, Figure 8(b) presents relay-filtered measurements, showing that while the angle of the negative-sequence voltage remains stable throughout the fault, the angle of the negative-sequence current continuously varies [11]. This dynamic behaviour can lead to inconsistent directional discrimination by protection systems.

Grid Forming and Grid Following Inverter Fault Current Contribution



(a)



(b)

Figure 8 Variations in negative-sequence: (a) current-voltage phase relationship, (b) phase angle variations

- FRT Requirements: Other than a couple of exceptions, for example, in Germany and IEEE Std 2800-2022, regulatory requirements for FRT often result in controlled and limited negative-sequence current contributions, further challenging traditional protection systems.

4.3.2.2 Comparison with Synchronous Generators

- Synchronous generators naturally generate substantial and stable negative-sequence currents under unbalanced faults, providing a clear and reliable signal for relays to detect and localise faults.

Reference [1] illustrates the measurement of a negative sequence forward directional relay (device 32GF) for a Phase B-to-ground fault, which, after three cycles, evolved into a Phase B-to-C-to-ground fault. The positive sequence voltage is used as the reference, with phasors rotating counterclockwise. The strong synchronous generator-dominated system contributed substantial zero- and negative-sequence currents, with their phase angles leading their respective sequence voltages by approximately 90° , as expected in a conventional synchronous system with an inductive path to a forward short-circuit fault. This phase angle remained

Grid Forming and Grid Following Inverter Fault Current Contribution

consistent even as the fault transitioned from a Phase B-to-ground fault to a Phase B-to-C-to-ground fault and did not change until after fault clearance. The negative sequence forward directional element asserted shortly after fault inception and remained active until the fault was cleared.

- In contrast, the low and dynamically controlled negative-sequence currents from IBRs may be insufficient to trigger relays designed for traditional systems.

Reference [1] presents relay records from the wind farm within the same power system discussed above, capturing the forward fault current contribution from the wind turbine generation. The negative-sequence current was below 90 A and was nearly in anti-phase with its corresponding sequence voltage. This indicates that the phase angle relationship between the negative-sequence current and voltage in a Type III wind turbine generator differs from that of conventional synchronous sources and is not easily predictable. The negative-sequence forward directional element asserted transiently during the event, highlighting unreliable and inconsistent decision-making.

4.3.2.3 Implications for Protection Relays

4.3.2.3.1 Directional Relays

These relays often rely on the direction of negative-sequence current to determine fault location. Insufficient negative-sequence current can lead to a failure in directional discrimination, causing incorrect fault identification or failure to trip.

4.3.2.3.2 Negative-sequence Overcurrent Relays

These relays may fail to operate entirely in systems dominated by IBRs due to the low magnitude of negative-sequence currents, reducing the overall sensitivity of the protection scheme.

4.3.2.3.3 Distance Relays

Apparent impedance calculations rely partly on sequence components. Dynamic and inconsistent negative-sequence contributions can distort impedance trajectories, leading to underreach or overreach.

4.3.2.4 Mitigation Strategies

- **Adaptive Relay Settings:** Lowering thresholds for negative-sequence current detection can improve sensitivity, though it may increase the risk of false positives.
- **Integration of Zero-Sequence Current:** Where system grounding allows, zero-sequence components can supplement negative-sequence-based fault detection to improve reliability.
- **Advanced Control Algorithms:** Development of control algorithms for IBRs that inject controlled negative-sequence currents during faults could enhance relay compatibility.
- **Model Validation:** Using EMT simulations to model negative-sequence behaviours under different fault scenarios can help refine relay settings and improve coordination.
- **Enhanced Performance for IBR Negative-sequence Current Contribution:**
 - Revise access standards or define system services to specify a higher and more constant negative-sequence fault current contribution.

Negative sequence current injection in the current clause S5.2.5.5. of the NER is set out as per below:

Grid Forming and Grid Following Inverter Fault Current Contribution

The reactive current contribution required may be calculated using phase-to-phase, phase-to-ground or sequence components of voltages. The ratio of the negative sequence to positive sequence components of the reactive current contribution must be agreed with AEMO and the Network Service Provider for the types of disturbances listed in this clause S5.2.5.5;

However, in practice, many factors impact the amount of negative sequence current injected, and having a single ratio of negative sequence to positive current component of the reactive current is neither practically possible nor will it help address a real issue in the power system. It is recommended to develop a new requirement similar to that set out in IEEE Std 2800-2022, which requires the IBR unit to inject negative sequence current during unbalanced faults with key attributes indicated below [13]:

- Dependent on IBR unit terminal (POC) negative sequence voltage and
- That leads the IBR unit terminal negative sequence voltage by between 90 and 180 degrees

Note that, unlike the requirement set out in VDE 4120 [14] and 4130 [15], IEEE Std 2800-2022 does not specify the amount of negative sequence current injection as a function of negative sequence voltage, i.e. K-factor for negative sequence. This is because a single value or range of values will not necessarily achieve the best outcome for the overall power system security. An unnecessarily high negative-sequence current will adversely impact other access standards and the provision of system services. In contrast, too low a negative-sequence current injection might impact the plant's own stability or the correct operation of protection systems.

4.3.3 Variable phase angle

IBRs exhibit greater variability in phase angle during faults compared to synchronous machines. This is due to their reliance on fast controls, which adjust outputs dynamically in response to system conditions. Relays relying on phase angle or sequence-based calculations, such as directional or negative-sequence relays, may misinterpret these changes, leading to incorrect fault direction identification or misoperation. The phase angle variability in IBRs is influenced by their control strategies and rapid response mechanisms, and it has a critical impact on protection relay performance:

4.3.3.1 Characteristics of Phase Angle Variability in IBRs

- **Dynamic Control Responses:** IBRs rely on fast control systems that adjust the phase angle rapidly to maintain voltage and current balance. This dynamic adjustment often results in non-linear phase angle changes during fault conditions.
- **GFL:** These inverters use phase-locked loops (PLLs) to synchronise with the grid frequency. Fault-induced disturbances can disrupt PLL operations, leading to erratic phase angle shifts.
- **GFM:** While GFMs are more stable, their phase angle dynamics are still faster than synchronous generators due to the lack of mechanical inertia.

Figure 9 presents a real-world wind farm case where Zone 1 overreached, leading to a misoperation [16]. The estimated expansion vector for this forward fault is depicted in Figure 10, showing a continuous drift in angle over time [16]. Initially, at time t_1 , the estimated angle was in the third quadrant, but by t_2 , it had shifted into the fourth quadrant. This gradual transition caused the Mho characteristic to drift from the third to the fourth quadrant over time.

Grid Forming and Grid Following Inverter Fault Current Contribution

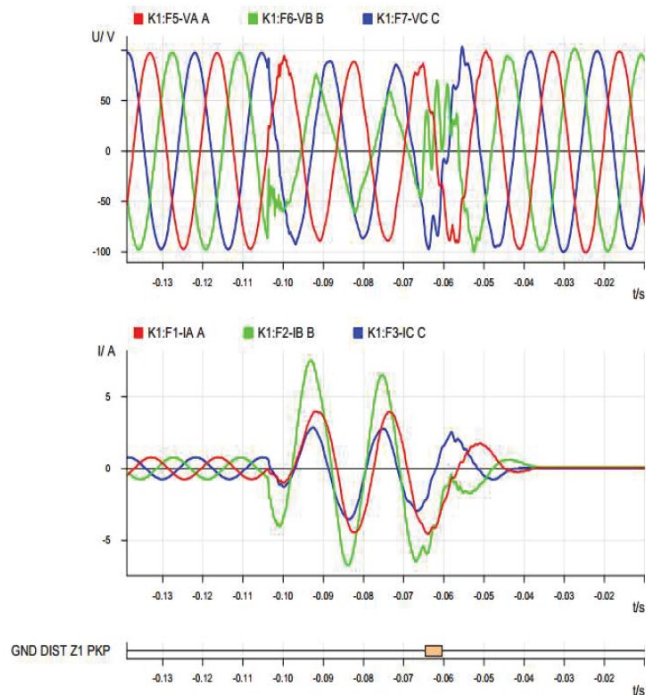


Figure 9 Zone 1 Ground element overreach [16] (This figure has been reproduced with permission from The IET, 2022)

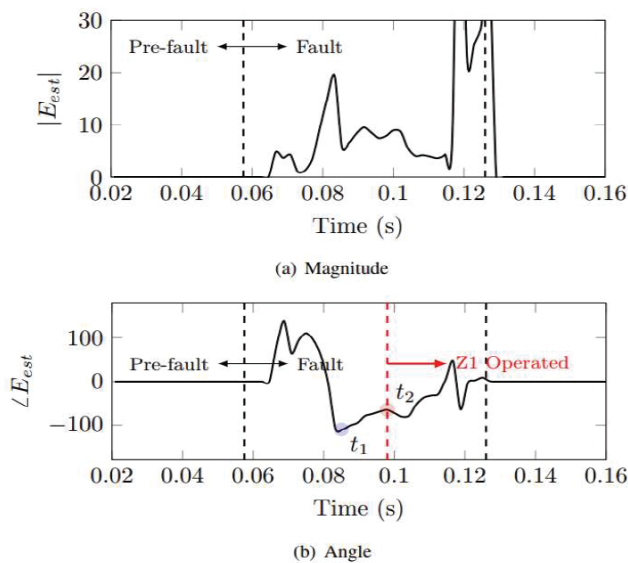


Figure 10 Estimated dynamic impedance comprising impedance magnitude and phase angle [16] (This figure has been reproduced with permission from The IET, 2022)

4.3.3.2 Comparison with Synchronous Generators

- Synchronous generators maintain a relatively stable phase angle during faults because of their inherent inertia. The slower dynamics and mechanical coupling limit rapid changes in phase angle, providing a predictable response for relay algorithms.
- In contrast, IBRs can create abrupt and irregular phase angle changes, which can lead to confusion in relays designed to interpret steady-state or slow-varying phase angles.

Grid Forming and Grid Following Inverter Fault Current Contribution

4.3.3.3 Implications for Protection Relays

4.3.3.3.1 Directional Relays

These relays rely on phase angle differences to detect the direction of power flow and fault location. Erratic phase angle shifts in IBRs may cause directional relays to misinterpret fault direction, resulting in incorrect tripping or failure to trip.

4.3.3.3.2 Negative-sequence Relays²

The variability in phase angle between phases can distort the calculation of sequence components, particularly when coupled with low negative-sequence currents.

4.3.3.3.3 Distance Relays

Apparent impedance trajectories observed by distance relays are affected by phase angle variability, leading to underreach or overreach scenarios. This variability particularly affects memory-polarised mho relays, which rely on consistent phase angle references.

4.3.3.4 Mitigation Strategies

- **Adaptive Algorithms:** Protection relays need adaptive algorithms capable of handling fast phase angle variations and dynamically adjusting thresholds based on IBR behaviour.
- **Enhanced Modelling and Testing:** EMT simulations can help model IBR phase angle dynamics under various fault scenarios, ensuring better relay coordination.
- **Hybrid Control Systems:** Combining virtual impedance and droop control in GFMs can stabilise phase angle variability, improving relay compatibility. A more detailed discussion on the impact of GFM control will be presented in Section 4.5.

4.3.4 Sizeable Harmonics, Interharmonics and Fast Transients Content

- IBRs can introduce significant harmonic and interharmonic content during faults, posing significant challenges to the operation of protective relays. These non-fundamental waveform components are caused by fast switching of semiconducting switching devices and the fast control mechanisms in IBRs.

4.3.4.1 Characteristics of Sizeable Harmonics, Transients, and Interharmonics Content in IBRs

- **Harmonic Content:** Generated by the rapid switching of semiconducting switching devices, harmonic content in fault currents often includes higher-order frequencies that distort the fundamental waveform.
- **Interharmonics:** Occur between integer multiples of the fundamental frequency, which can be caused, for example, by control instabilities or interaction of multiple inverters.
- **Transient Noise:** Arises during fault initiation, clearing, or rapid control adjustments, introducing high-frequency noise that could mask the true fault signal.

Figure 11 shows relay currents and voltages for a forward Phase-B-to-ground (BG) fault on a transmission line, where the system behind the relay is an unconventional source (a wind farm) [17]. The currents exhibit significant distortion and do not follow the typical pattern of a BG

² Note that the term negative-sequence relay refers to a group of protection relays, including directional elements in distance and over-current relays, which rely on negative-sequence current measurements for decision making rather than a distinct type of relay.

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fault. Additionally, the faulted phase voltage (V_B) is notably low. All relay input signals are heavily distorted.

The transients in current and voltage measurements during faults, along with the relationship between RMS and fundamental frequency values, are critical factors. These recorded THD values from the actual fault event approached simultaneously 60% and 50% for the THD_v and THD_i , which resulted in mis-operation of distance protection [18]. As fault current levels decrease, the relative proportion of harmonics may increase, leading to calculation inaccuracies and potential protection misoperations. This observed behaviour in distance protection is unprecedented, warranting further study to understand evolving grid dynamics.

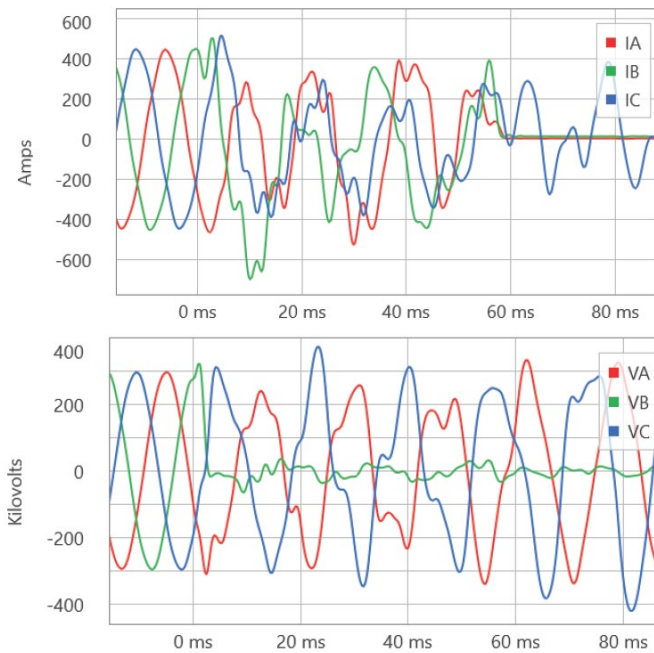


Figure 11 Line voltages and currents for a BG fault in a system with an unconventional source behind the relay (field record) [17] (This figure has been reproduced with permission from The IET, 2022)

4.3.4.2 Comparison with Synchronous Generators

- Harmonics: Synchronous generators produce fault currents with minimal harmonic distortion due to the absence of power electronic interfaces with the grid.
- Interharmonics: Rarely observed in synchronous generators but common in IBRs due to the interaction of multiple switching frequencies or multiple control systems.
- Transient Noise: synchronous generators exhibit predictable transient behaviour, while IBRs show rapid, complex transients due to their electronic nature.

4.3.4.3 Implications for Protection Relays

4.3.4.3.1 Overcurrent Relays

- Harmonic content increases the root mean square (RMS) current, leading to false trips when relays misinterpret the current magnitude.

4.3.4.3.2 Directional Relays

- Phase distortion from harmonics can confuse relays relying on phase angle differences for fault direction identification.

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4.3.4.3.3 Distance Relays

- Apparent impedance is skewed by harmonic components, causing overreach (relay operates farther from the fault than expected) or underreach (relay fails to operate for nearby faults).

4.3.4.3.4 Negative-sequence Relays

- Harmonics reduce the accuracy of negative-sequence current calculations, leading to failure in detecting unbalanced faults.

4.3.4.3.5 Differential Relays

- Transient noise and harmonics disrupt the balance between primary and secondary currents, causing unnecessary tripping.

4.3.4.4 Mitigation Strategies

- Harmonic Filtering:
 - Install advanced software-based harmonic filtering on relay inputs to remove non-fundamental components. This could include low-pass filters, wavelet transforms, or adaptive notch filters in relays to suppress high-frequency noise while preserving fault signals.
- Adaptive Relay Algorithms:
 - Design relays that differentiate between harmonic distortions and actual fault signals.
- Hybrid Relays:
 - Use protection systems combining traditional methods with adaptive or machine-learning-based techniques to enhance performance in high-harmonic environments.
- Improved Testing:
 - Conduct hardware-in-the-loop (HIL) testing to evaluate relay performance under harmonic and transient-rich conditions.
- Enhanced Performance for IBR's Harmonic and Interharmonic Content During the Fault:
 - Revise access standards to specify a maximum permissible level of harmonics and interharmonics during the fault.

4.3.5 Impedance Variations [16] [19] [20] [21] [22]

- The dynamic control mechanisms and rapidly changing impedance characteristics of IBRs significantly affect the operation of protection systems. These behaviours, introduce challenges for traditional impedance-based relay schemes.

4.3.5.1 Characteristics of Impedance Variations in IBRs

- Dynamic Impedance Response: IBRs dynamically adjust their impedance to manage fault currents and protect internal power electronic components. This behaviour results in variable and non-linear apparent impedance during faults.
- Fast Control Dynamics: Control mechanisms in IBRs, such as current-limiting strategies in GFL and GFM controls, react in milliseconds, potentially introducing rapid shifts in system impedance.

Grid Forming and Grid Following Inverter Fault Current Contribution

- Proprietary Controls: Different manufacturers implement varying control strategies, leading to non-uniform impedance responses across devices (this will be discussed in more detail in Section 4.3.6).

Figure 12 presents the equivalent impedance of IBRs using virtual impedance-based GFM control and balanced current injection-based GFL control and compares with the internal impedance of a voltage source, i.e. a synchronous generator [20]. As shown, unlike synchronous generators, which can be approximated as voltage sources with constant source impedance, IBRs exhibit dynamic and time-varying internal impedance characteristics.

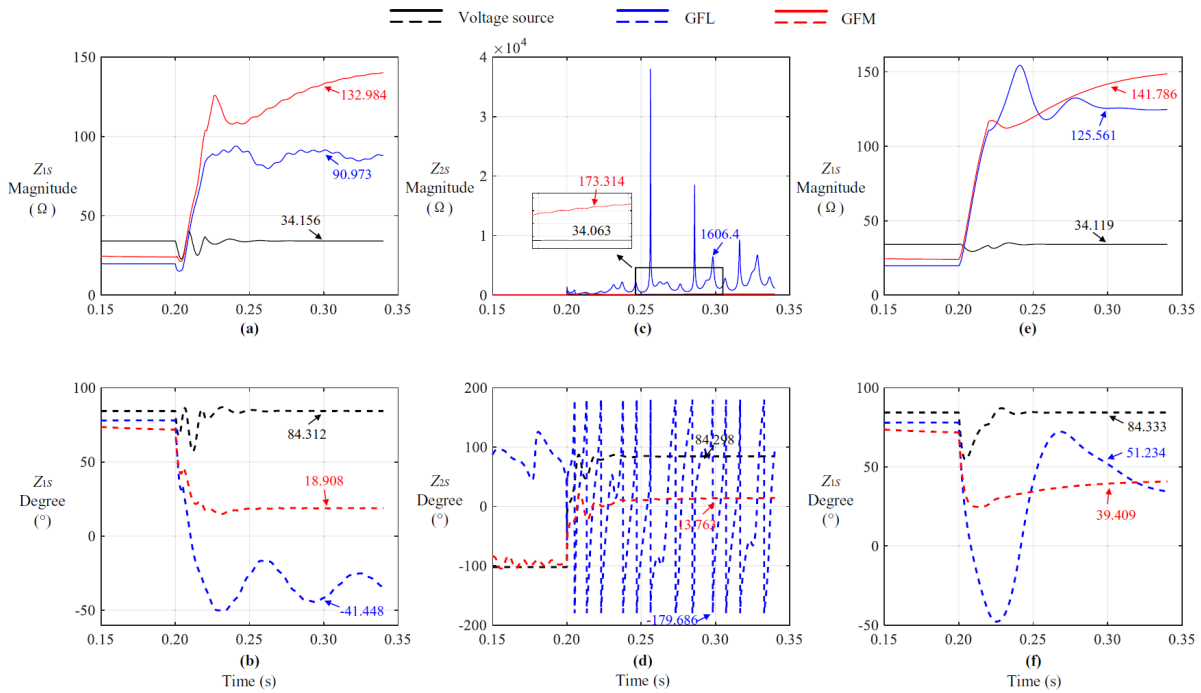


Figure 12 The equivalent impedance of synchronous generator, GFL and GFM [20] (This figure has been reproduced with permission from The IET, 2024)

4.3.5.2 Comparison with Synchronous Generators

- Stable Impedance:** synchronous generators exhibit relatively constant impedance characteristics during faults due to their mechanical and electromagnetic properties.
- Predictable Fault Behaviour:** The impedance trajectory for synchronous generators remains linear and proportional to the fault, providing reliable data for protection systems.
- Dynamic Control:** In contrast, IBRs introduce non-linear and rapidly changing impedance values that traditional distance relays and other protection schemes are not designed to interpret.

4.3.5.3 Implications for Protection Relays

4.3.5.3.1 Distance Relays

- Apparent impedance may change dynamically, causing underreach (failure to trip for nearby faults) or overreach (tripping for faults outside the intended zone).
- Rapid changes in fault impedance trajectories can mislead relay algorithms based on steady-state assumptions.

Grid Forming and Grid Following Inverter Fault Current Contribution

4.3.5.3.2 Differential Relays

- The impedance mismatch between primary and secondary zones can cause differential relays to misoperate. If one end of a transmission line is fed by an IBR and the other by a traditional generator or strong grid, the relay may see a significant current imbalance even during external faults, leading to misoperation.

4.3.5.3.3 Directional Relays

- Variations in fault impedance during control adjustments can disrupt the detection of fault direction.

4.3.5.3.4 Out-of-Step and Power Swing Blocking

- Impedance swings during fault clearing may trigger out-of-step conditions or disable power swing blocking mechanisms prematurely.

4.3.5.4 Mitigation Strategies

- Adaptive Relay Algorithms:
 - Develop relays with dynamic algorithms capable of responding to variable impedance patterns. Such relays should adaptively adjust their trip thresholds and operating zones by:
 - Monitoring the Short-Circuit Ratio (SCR) to assess the likelihood of impedance variability.
 - Tracking real-time fault current levels to ensure relay settings are responsive to actual system conditions.
 - Comparing pre-fault and post-fault impedance changes, allowing relays to adjust their reach dynamically and avoid misoperation during IBR-induced impedance fluctuations.
 - Incorporating voltage- and frequency-dependent impedance settings to account for IBRs' control-driven current limitations.
 - By implementing these real-time adaptive adjustments, relays can distinguish between natural IBR impedance shifts and genuine fault conditions, reducing misoperations in high-IBR networks.
- Improved System Modelling:
 - Use EMT simulations to model and predict the dynamic impedance behaviours of IBRs under different fault scenarios.
- Hybrid Protection Schemes:
 - Combine impedance-based methods with current differential and voltage-based techniques to enhance reliability in dynamic environments.
- GFM-Specific Adjustments:
 - Grid-forming inverters with virtual impedance strategies can be fine-tuned to provide more stable impedance profiles, reducing the variability that impacts relay performance.
- Enhanced Performance for IBR's Impedance Variations During Faults:
 - Revise access standards to specify a maximum acceptable impedance variation during the fault. This could differ between the GFL and GFM requiring further studies in the second stage of this project to determine.

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4.3.6 Proprietary Control Algorithms

- Proprietary control algorithms in IBRs introduce significant variability in fault responses, which complicates the performance of traditional protection systems. Each manufacturer's implementation of control strategies, tailored to optimise inverter operation and frequently incorporating proprietary intellectual properties (IPs), creates challenges for standardised protection schemes.

4.3.6.1 Characteristics of Proprietary Control Algorithms in IBRs

- Non-Standardised Behaviour: IBRs use proprietary algorithms that differ in how they manage current output, FRT and system stability, leading to diverse fault characteristics.
- Adaptive Responses: These algorithms can continuously adjust the inverter's output based on internal logic, grid conditions, and fault parameters, resulting in dynamic and unpredictable responses during faults.
- Control Variability: The lack of uniform control strategies among manufacturers introduces inconsistencies in fault current magnitude, phase angle, and sequence component contributions.

4.3.6.2 Comparison with Synchronous Generators

- Predictable Response: Synchronous generators follow well-defined physical principles and standardised operating characteristics, leading to predictable fault responses.
- Uniform Fault Contribution: synchronous generators provide consistent fault current levels and sequence components regardless of manufacturer differences.
- Static Behaviour: Unlike IBRs, synchronous generators lack dynamic control algorithms, minimising variability in their fault responses.

4.3.6.3 Implications for Protection Relays

The following points, previously discussed in earlier sections, are summarised here to emphasise the additional impact of proprietary control algorithms on all aspects covered in Section 4.3.

4.3.6.3.1 Overcurrent Relays

- Variability in fault current magnitude due to proprietary algorithms can prevent consistent relay operation.

4.3.6.3.2 Distance Relays

- Apparent impedance may shift unpredictably due to dynamic changes in fault current and system impedance, leading to overreach or underreach.

4.3.6.3.3 Directional Relays

- Phase angle discrepancies caused by adaptive control responses may mislead directional relays, resulting in incorrect fault detection or miscoordination.

4.3.6.3.4 Negative-sequence Relays

- Some proprietary algorithms suppress negative-sequence current during faults, rendering these relays ineffective.

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4.3.6.3.5 Differential Relays

- Differences in fault response timing and magnitude between protected zones can disrupt current differential calculations, causing false tripping or failures.

4.3.6.4 Mitigation Strategies

- Standardisation Efforts:
 - Develop and enforce access standards requiring consistent fault response characteristics across IBR manufacturers to improve relay compatibility.
 - The revised access standards suggested in Sections 4.3.1, 4.3.2, 4.3.4 and 4.3.5 will assist in achieving more standardised and consistent responses across different manufacturers.
- Advanced Relay Algorithms:
 - Design relays with adaptive capabilities to handle dynamic and proprietary control-induced variability.
- Model Validation:
 - Use EMT simulations to validate relay performance against a wide range of proprietary IBR control behaviours.
- Manufacturer Collaboration:
 - Collaborate with manufacturers to provide detailed inverter control models for protection studies.
- Hybrid Protection Systems:
 - Implement protection systems that combine multiple detection methods to compensate for inconsistencies in IBR fault characteristics.

4.3.7 Frequency Estimation Challenges

Frequency tracking plays a crucial role and impacts the decision of any protection element which is based on phasor information.

4.3.7.1 Characteristics of Frequency Estimation

- IBRs often complicate accurate frequency estimation during transient events due to their fast dynamic responses and harmonic distortions. Relays dependent on precise frequency calculations, such as frequency or RoCoF relays, may experience delays or inaccuracies, reducing their reliability. This issue is especially pronounced in weak grids or systems dominated by IBRs.

Figure 13 presents the raw frequency after pre-processing for a real-world case where rapid frequency drift occurred in the presence of renewable generation, leading to a Zone 1 misoperation [16]. A key observation is the mismatch between the frequencies of the voltage and current signals.

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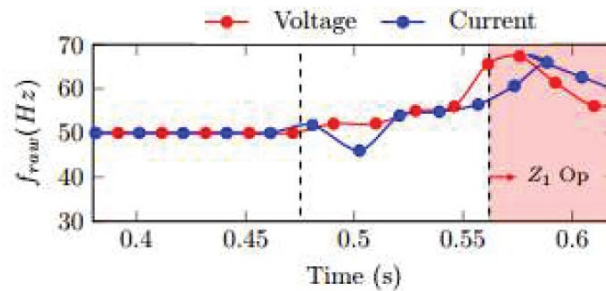


Figure 13 Zone 1 mis-operation due to frequency drift [16] (This figure has been reproduced with permission from The IET, 2022)

4.3.7.2 Comparison with Synchronous Generators

In conventional power system with a high share of synchronous generators, the inertia of the rotating shaft limits abrupt frequency changes during disturbances. However, with IBRs rapid and significant variations may occur.

4.3.7.3 Mitigation strategies

To improve frequency estimation reliability, the following solutions can be considered:

- Enhanced Frequency Estimation Algorithms
 - Traditional phasor-based frequency estimators struggle with IBR-induced distortions.
 - Using adaptive signal processing techniques, such as Kalman filters, PLLs, and wavelet transforms, can improve frequency accuracy.
- Hybrid Frequency Tracking Approaches
 - Combining zero-crossing detection with phasor-based methods can enhance frequency stability under transient conditions.
 - Model-based frequency estimation leveraging dynamic system responses can help differentiate actual system frequency changes from control-induced disturbances.
- Harmonic Filtering and Noise Rejection
 - Implementing digital notch filters to remove dominant harmonic components in the presence of IBR-driven distortions.
 - Multi-rate signal processing techniques can separate fundamental frequency components from harmonics.
- Redundant and Multi-Point Measurements
 - Instead of relying on single-point frequency estimation, using wide-area measurement systems (WAMS) and PMUs (Phasor Measurement Units) can provide a more stable reference frequency in weak grids.
 - Averaging techniques across multiple measurement points can mitigate local distortions.

4.3.8 Summary of Implications for Protective Relays

Table 3 summarises the key issues discussed in Section 4.3 for each significant relay considered in this report.

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Table 3 Summary of implications for protective relays based on relay type

Section	Overcurrent Relays	Distance Relays	Directional Relays	Negative-Sequence Relays	Differential Relays	Frequency Relays
3.3.1.3 Insufficient and Variable Fault Current Magnitude	May not operate due to insufficient fault current magnitude.	Apparent impedance calculations are impacted, leading to underreach or overreach.	Fluctuating fault currents disrupt phase angle measurements, leading to incorrect fault direction detection.	N/A – These relays depend on sequence components, not fault current magnitude.	N/A – Differential relays primarily compare current in/out rather than absolute magnitude.	N/A – Frequency relays do not rely on fault current magnitude.
3.3.2.3 Insufficient and Variable Negative-Sequence Component	N/A – Overcurrent relays typically do not rely on sequence components.	Apparent impedance calculations may be distorted due to a lack of negative-sequence contribution.	Limited negative-sequence current may prevent proper directional detection of unbalanced faults.	May fail to detect unbalanced faults due to low or absent negative-sequence current.	N/A – Differential protection does not rely on sequence components.	N/A – Frequency relays do not rely on sequence components.
3.3.3.3 Variable Phase Angle	N/A – Overcurrent relays are primarily dependent on magnitude, not phase angle.	Phase angle variability may cause misinterpretation of impedance zones.	Erratic phase angles can cause incorrect directional discrimination.	Variable phase angles distort sequence component calculations, reducing effectiveness.	N/A – Phase angle changes do not directly impact differential protection.	N/A – Frequency relays are not dependent on phase angle.
3.3.4.3 Sizeable Harmonics, Interharmonics and Fast Transients Content	False trips due to harmonics increasing the RMS current.	Harmonic distortion affects impedance calculations, leading to incorrect operation.	Harmonics distort phase angle calculations, affecting directional relay performance.	Harmonics may interfere with negative-sequence calculations, leading to incorrect operation.	Harmonics and transients may introduce false differentials, causing unnecessary trips.	N/A – Frequency relays are not affected by harmonics directly.

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Section	Overcurrent Relays	Distance Relays	Directional Relays	Negative-Sequence Relays	Differential Relays	Frequency Relays
3.3.5 .3 Impedance Variations	N/A – Impedance variations primarily affect impedance-based relays.	Dynamic impedance changes lead to underreach or overreach errors.	Rapid impedance variations can interfere with directional decision logic.	N/A – Negative-sequence relays are not impedance-dependent.	Impedance variations between zones can lead to incorrect fault detection.	N/A – Frequency relays do not rely on impedance measurements.
3.3.6.3 Proprietary Control Algorithms	Unpredictable responses may cause inconsistent fault detection.	Non-uniform inverter responses create inconsistencies in impedance calculations.	Different inverter manufacturers may have inconsistent phase angle responses, affecting directional decisions.	Some inverter algorithms suppress negative-sequence currents, rendering these relays ineffective.	Timing mismatches from proprietary algorithms may disrupt differential calculations.	N/A – Frequency relays are not impacted by inverter control algorithms.
3.3.7.3 Frequency Estimation Challenges	N/A – Overcurrent relays are not frequency-dependent.	N/A – Distance relays are not directly affected by frequency estimation issues.	N/A – Directional relays do not rely on frequency estimation.	N/A – Negative-sequence relays are not frequency-dependent.	N/A – Frequency estimation does not directly impact differential relays.	Harmonic distortions and fast dynamic response lead to inaccuracies in frequency measurement, causing misoperation.

4.4 GFM vs. GFL Inverters

The discussions so far have primarily focused on common characteristics shared by all IBRs. However, key differences exist between GFL and GFM inverters, which are summarised in Table 4. These distinctions have implications for their interaction with protection systems and overall grid performance.

Note that significantly more experiences have been gathered from international system incidents regarding the impact of GFL inverters on protection systems (See Section 5). The same level of operational experience with GFM inverters has not yet been obtained, highlighting the need for further investigation into their behaviour and implications. The need for additional research is emphasised in several cells of the table.

Table 4 Comparison of GFL and GFM with respect to the impact on relay performance

Aspect	GFL	GFM
Fault Current Contribution	Fault current is limited and usually variable.	Some designs provide more stable fault current characteristics, though still limited current magnitude and nearly the same as that provided by a GFL. Oversized GFM inverters with uprated semiconducting switching devices can be sourced from a couple of manufacturers. The additional cost should be carefully considered.
Dynamic Response	Variable dynamic responses and inconsistency across manufacturers can confuse relay algorithms.	Requires further investigation in the second stage of this project, also leveraging on learning from other AEMO initiatives, such as GFM access standards review
Negative Sequence Contribution	Typically suppresses negative-sequence components, as a positive-sequence current prioritisation is generally preferred by most grid codes and by control system designers. However, negative-sequence current control can be delivered by most manufacturers.	No significant difference with GFL. However, the capability to deliver multiple desirable grid support functions may result in an even lower current being available in GFM inverters compared to GFL inverters for allocation to the negative-sequence component.
Impedance Variability	Variable apparent impedance.	Better control over apparent impedance and less variation during faults, at least with some control strategies (See Section 4.5). Further work is recommended to gain a more comprehensive understanding of

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Aspect	GFL	GFM
		GFL and GFM differences with respect to impedance variability.
Interaction with Weak Grids	Susceptible to instability in weak grids, increasing relay misoperation risks. This is particularly true for relays which either use harmonics or interharmonics for decision-making or are likely to get confused by the presence of high harmonics or interharmonics.	Enhances stability in weak grids.

4.5 Comparative Analysis of Control Strategies for GFM Inverters [22] [23] [24] [25] [26] [27]

4.5.1 FRT strategies for GFM

4.5.1.1 Current Control-Based FRT

In this approach, GFM inverters transition to GFL mode during faults to limit fault current. This approach requires a backup PLL for synchronisation with the main network during faults. Therefore, during the fault, this is essentially the same as the response of any other GFL. However, this mode transition from GFL to GFM can introduce undesired transients. With this approach, the inverter operates as a constant current source instead of a constant voltage source, making this strategy unsuitable for a system strength impact perspective.

4.5.1.2 Virtual Impedance-Based FRT

The virtual impedance-based FRT strategy involves incorporating a virtual impedance in the converter control loop to emulate an increase in the converter's output impedance, thereby limiting the current magnitude. This approach enables the converter to maintain its voltage source behaviour before, during, and after faults, offering a reliable solution for current limitation in GFMs. However, as the virtual impedance cannot instantly adjust the current amplitude, transient currents may occur during the initial period of a fault in this FRT structure.

4.5.1.3 Current Reference Saturation-Based FRT

This FRT method limits fault current by saturating the current references within an additional inner current controller. The saturated current references can lead to voltage regulator saturation, and eventual wind-up and instability in the GFM. These challenges can compromise system stability and reliability during faults.

4.5.1.4 Power Reference Readjustment-Based FRT

This strategy limits fault current by scaling down the power references of GFMs. The reactive power injected during faults can be controlled by adjusting the reactive power reference. Although effective, this method is less commonly employed compared to the other FRT strategies for GFMs.

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4.5.1.5 Voltage limiter

GFM control regulates the phase current magnitude by reducing the difference between the inner voltage and the point of coupling (POC) voltage via voltage limiters.

4.5.2 The Impact of Various GFM Controls on Protection System Performance

4.5.2.1 Current limitation

4.5.2.1.1 Advantages

- Simplified Local Relay Settings:
 - The predictable fault current behaviour of current-limiting IBRs reduces the variability in individual relay settings, particularly for overcurrent relays, making configuration easier.

4.5.2.1.2 Disadvantages

- Low Fault Current Magnitude:
 - Limiting fault current often reduces it below the sensitivity thresholds of traditional overcurrent relays, leading to missed fault detection and delayed protection response.
- Impairment of Distance Relays:
 - Distance relays rely on accurate impedance calculations, which can be distorted by the dynamic current limitation behaviour of GFMs, resulting in relay overreach or underreach.
- Transient Voltage and Current Disturbances:
 - Current saturation strategies can induce transient oscillations, especially during the initial fault period, potentially causing misoperations in differential and directional relays.
- Negative Sequence Current Suppression:
 - Some current-limiting strategies suppress negative-sequence currents, which are critical for directional and phase-selective relays to operate effectively under unbalanced fault conditions.
- Complex System-Wide Coordination:
 - While local relay settings may be simpler, the overall coordination of distance, directional, and differential protection schemes becomes more challenging.
- Risk of Voltage Regulator Saturation:
 - During prolonged faults, current saturation can cause voltage regulator saturation and potential instability.

4.5.2.2 Droop

4.5.2.2.1 Advantages

- Predictable Fault Current Contribution:

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- Droop-controlled GFM can deliver a controlled fault current magnitude that aids in ensuring consistent relay performance, particularly for distance and overcurrent relays.
- Well-Controlled Current Injection:
 - GFM droop-controlled inverters limit their fault current in a predefined manner, ensuring that it remains within expected bounds.
- Ease of Coordination:
 - The proportional response to power changes makes it easier to coordinate with traditional protection settings, improving the reliability of overcurrent and directional protection schemes.
- Enhances Islanded Operation:
 - Droop-controlled GFMs can operate autonomously in islanded systems, ensuring protective relays continue functioning by providing a stable voltage source without relying on the external grid.

4.5.2.2.2 Disadvantages

- Dynamic Impedance Variation:
 - The equivalent impedance seen by the relay varies dynamically with the power system's operating conditions, which can lead to relay overreach, underreach, or instability.
- Transient Response Issues:
 - It can introduce transient oscillations and dynamic impedance variations (as mentioned in the above bullet point), which may affect distance, differential, and directional relay performance, leading to overreach, underreach, or delayed tripping.
- Challenges with Negative Sequence Currents:
 - Droop-controlled GFMs typically do not inject sufficient negative-sequence current during unbalanced faults. This lack of negative-sequence current can hinder the performance of directional and differential protection schemes.
- Complex Coordination with Traditional Systems:
 - Relay coordination becomes more complex in hybrid systems where synchronous generators and droop-controlled GFMs coexist, as their fault responses differ significantly.

4.5.2.3 Virtual impedance

4.5.2.3.1 Advantages

- Enhances Distance Relay Stability:
 - Virtual impedance control modifies the fault response of GFMs, enabling them to mimic synchronous machine behaviour by stabilising impedance and preventing excessive impedance fluctuations.
- Maintains Voltage Source Behaviour:

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- Virtual impedance allows GFMs to maintain constant voltage source characteristics during faults.
- Flexible Implementation:
 - Virtual impedance can be tuned to balance transient performance and steady-state stability, enabling better integration with traditional protection schemes.
- Reduces Transient Overvoltages:
 - By smoothing fault current injection, virtual impedance minimises transient overvoltages, improving the performance of protection relays under dynamic grid conditions.

4.5.2.3.2 Disadvantages

- Dynamic Impedance Variability:
 - If virtual impedance is actively adjusted during a fault, unlike in synchronous machines, it can change the impedance trajectory dynamically within a few ms, potentially misleading distance relays and causing incorrect tripping or miscoordination.
- Impact on Fault Current Magnitude:
 - While limiting fault current is beneficial for inverter protection, it can result in fault currents that are too low for traditional overcurrent relays to detect, compromising relay sensitivity.
- Challenges with Relay Coordination:
 - Variations in virtual impedance behaviour across different GFMs or control implementations can make it difficult to standardise relay settings, increasing the risk of relay misoperations.
- Transient Currents During Faults:
 - Virtual impedance adjustments can cause transient current oscillations, especially during the initial fault period, which may confuse differential and overcurrent relays.
- Complexity in Tuning:
 - Precise tuning of virtual impedance parameters is required to optimise protection performance. Poorly tuned systems may either fail to limit fault currents effectively or destabilise relay operations.
- Dependence on Control Strategy:
 - The effectiveness of virtual impedance depends heavily on the inverter's control strategy. Poorly designed control loops can exacerbate issues like delayed fault response or harmonic distortion, impacting relay accuracy.

5 Detailed Analysis of Incidents

5.1 Incident 1: Finland Harmonic-Induced Distance Relay Misoperation [18]

In a notable incident in Finland, excessive harmonic distortion in the grid caused a distance relay to misoperate, leading to the unnecessary disconnection of critical infrastructure. High levels of harmonics originated from IBRs and interacted with relay algorithms designed for traditional systems.

- **Relay Issues:** The distance relay, expecting sinusoidal waveforms, interpreted harmonic components as part of the fundamental signal, causing incorrect impedance calculations. This resulted in a false trip, disrupting system reliability.
- **Actions Taken:** Fingrid investigated advanced harmonic filtering and revised relay settings to mitigate similar occurrences in the future. Additionally, they initiated research into relays that incorporate harmonic-resistant algorithms for improved fault discrimination.

5.2 Incident 2: Sequence-Based Protection Misoperation in a Type III Wind Farm [1]

In a Type III wind plant scenario, directional negative-sequence relays misoperated due to inconsistencies in negative-sequence current contribution during faults. The incident occurred in a wind-dominated region of Northern Europe.

- **Relay Issues:** Limited and inconsistent negative-sequence current contributions led to incorrect fault direction detection by directional relays.
- **Actions Taken:** Recommendations included adopting directional zero-sequence elements where system grounding supports reliable zero-sequence current measurements and refining relay algorithms to handle low-magnitude sequence components.

5.3 Incident 3: Negative-Sequence Overcurrent Relay Misoperation in an IBR-Dominated Grid [1]

In a Type III wind plant scenario, misoperation of directional negative-sequence relays was observed due to inconsistent negative-sequence current contribution during faults. This incident, occurring in a wind-dominated region of Northern Europe, highlights the challenges of applying traditional directional protection in networks with high penetration of wind power.

- **Relay Issues:** The limited negative-sequence current contribution from IBRs caused the relay to fail in detecting and isolating faults. This misoperation resulted in extended fault clearance times and grid instability.
 - **Limited Negative-Sequence Current Contribution:**
 - Unlike synchronous generators, Type III wind turbines do not inherently produce strong negative-sequence current during unbalanced faults.

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- As a result, directional relays that rely on negative-sequence elements (67P) for fault direction detection struggled to operate correctly.
- Incorrect Tripping of Un-Faulted Feeder Relays:
 - During a BCG fault, the collector feeder breaker tripped correctly based on the 67P directional element.
 - However, the same 67P elements in relays on two unfaulted collector feeders misoperated, incorrectly detecting the fault as being within their protected zones.
 - This misoperation was caused by the lack of sufficient negative-sequence current from the wind turbines, which prevented the relays from accurately determining fault direction.
- **Actions Taken:** Adjustments to relay settings were made to lower detection thresholds. Utilities also explored introducing a controlled level of negative-sequence current during faults to enhance relay response.

5.4 Incident 4: Harmonic-Induced Misoperation of Relays in STATCOM-Dominated Grids [1]

In a European STATCOM-dominated grid, high harmonic and interharmonic content generated during a fault event caused severe misoperation of multiple relays, including distance and differential protection.

- **Relay Issues:** Harmonics distorted the fault current waveform, leading to inaccurate impedance calculations and incorrect trip signals. Differential relays were particularly affected by the presence of non-fundamental frequency components.
- **Actions Taken:** Advanced harmonic filtering technology was installed to mitigate the impact on relay performance. Additionally, new protection algorithms were tested to differentiate between harmonics and fault signatures.

5.5 Incident 5: Unbalanced Faults in Series-Compensated Lines [6]

An incident in South America involving series-compensated transmission lines demonstrated misoperation of directional and distance relays under unbalanced fault conditions. The series compensation dynamically altered the line impedance, complicating fault detection.

- **Relay Issues:** Relays were unable to adapt to the rapid changes in apparent impedance caused by the fault, resulting in incorrect fault location identification.
- **Actions Taken:** Hybrid protection schemes were introduced to combine impedance-based and current differential methods for improved fault detection and localisation.

Table 5 provides a tabular summary for all incidents related to relay misoperation under high penetration of IBRs discussed earlier in this Section.

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Table 5 A summary of real-life incidents involving misoperation of protective relays.

Incident	Location	Relay Issues	Actions Taken
Harmonic-Induced Distance Relay Failures	Finland	Harmonics misled distance relays, causing incorrect impedance calculations.	Installed advanced harmonic filtering; revised relay settings; initiated harmonic-resistant relay designs.
Negative-Sequence Relay Misoperation	Northern Europe	Limited negative-sequence currents caused directional relays to fail.	Recommended directional zero-sequence elements; refined relay algorithms.
STATCOM-Induced Relay Failures	Eastern Europe	Harmonics and interharmonics caused distance and differential relay misoperations.	Deployed harmonic filtering; introduced improved relay algorithms.
Unbalanced Faults in Series-Compensated Lines	South America	Dynamic impedance changes caused directional and distance relay misoperations.	Hybrid protection schemes combining impedance-based and current differential methods were applied.

6 Accurate Fault Current Calculation of IBRs

While recognising that some aspects of the challenges discussed in this document, such as the inclusion of harmonic and inter-harmonic content of fault current, require EMT simulations, there remains a strong application for phasor-domain fault current calculation tools. These tools are still valuable for calculating fault current, phase angle, and sequence behaviour, which are crucial for assessing the impact of IBRs on the operation of protection systems. Traditional fault calculation methods, including those defined in IEC 60909 or bespoke engines within different simulation programs, have historically been based on models and operating principles of synchronous machines, which are treated as voltage sources during faults. These conventional methods assume a predictable and relatively straightforward fault current contribution from synchronous machines, where the fault current is typically high and relatively stable. However, the dynamic and nonlinear fault responses of IBRs present a significant challenge to this approach. As observed in practical applications [28], there are noticeable discrepancies when comparing calculated fault currents with measured ones, especially during the fault event. This divergence highlights the limitations of using synchronous machine-based methods for IBRs, which behave fundamentally differently due to their current-limiting controls and the nature of their interactions with the grid.

This section delves into the enhancements made in some simulation tools to address these challenges. It explores how these tools, through iterative phasor-domain calculations, can now more accurately capture the complex fault responses of IBRs. The modifications in the models and algorithms reflect a deeper understanding of IBR behaviour, particularly their precise FRT behaviour. By incorporating these advancements, the updated simulation tools are better equipped to calculate fault current, sequence components, and phase angles, leading to more reliable assessments of protection system performance. The improvements made to these simulation tools are essential for achieving a more accurate fault analysis, enabling a more accurate assessment of the impact of IBRs on protection systems.

The main consideration is that IBRs should be modelled as voltage-dependent current sources, as opposed to the traditional voltage source models used for synchronous machines. This method reflects the nonlinear fault response characteristics of these devices due to their power electronic converters.

- **Rationale:** The fault current contribution of an IBR depends on its residual voltage. However, the relationship between inverter current and residual voltage is nonlinear, necessitating extensive testing or high-resolution transient simulations. The control system can include features such as dynamic reactive current control, i.e. the so-called K-factor, or current limiting.
- **Data for Modelling:** The proposed model requires a tabular data structure where manufacturers provide the necessary data on fault behaviour, such as sequence voltages and currents over time. Alternatively, the table can be produced from an EMT time-domain simulation. This data is necessary for modelling the IBR response at different voltage levels and during different fault conditions, which allows simulation tools to capture the non-linear fault current contributions from these units.

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Separate data is required to capture the positive-sequence and negative-sequence behaviours. This is regardless of whether the negative-sequence current is injected, absorbed or cancelled out by the inverter. One dataset is required per cycle during the fault. Also, different data is required for different active power levels and control system settings if they have an impact on fault current.

Several algorithms are used to implement these models in commercial fault calculation software. Various software platforms, including bespoke simulation programs, have developed different approaches for incorporating these models into their short-circuit analysis tools. The commonalities between these platforms include the iterative solution methods required to model the behaviour of IBRs due to their nonlinear control systems.

- **Iterative Solution Methods:** Because the fault response of IBRs is nonlinear, conventional short-circuit analysis tools, which typically solve the system in one step, cannot be directly applied. Instead, these tools use an iterative approach where the network is linearised at each iteration, adjusting the current injections of the IBRs based on the voltage conditions until convergence is achieved. This approach ensures that the fault responses are accurately modelled, especially when considering the impact of the converters' control systems.
- **Data Requirements:** All the platforms reviewed require similar data inputs, such as fault type, voltage magnitude, and current sequences. The format for this data typically includes tabular data that represents the IBR's response to various terminal voltages and fault conditions, which is used to adjust the current injections during each iteration.
- **Control Mode Adaptation:** All platforms take into account the control strategies of the IBRs. These include options such as constant real power, constant power factor, and dynamic reactive current control. The simulation tools allow for different control modes to be implemented, ensuring flexibility to model various manufacturers' control systems.
- **Voltage and Current Limiting:** Common among these tools is the need to handle current limiting during faults. In cases where the IBR's current output exceeds the thermal limits of the converter, the simulation tools adjust the current to stay within these limits. This is a critical feature for accurately modelling fault conditions, as the converter's response during a fault is significantly influenced by whether it is in a limiting mode.

7 Protection System Modelling Recommendations

7.1 Integrated Power System Dynamic Modelling Including IBRs and Protection Systems

7.1.1 Dynamic Modelling of Relays

- Include time-domain models of critical protective functions such as impedance-based protection (including distance relays) with and without directional element, differential protection, and directional overcurrent relays.
- Model relevant aspects of the operating logic of protective relays, including their dynamic response to varying fault current magnitude, phase angle and impedance, harmonics and any filtering used.

7.1.2 Scenarios for Dynamic Analysis

To address the challenges posed by IBRs in protection systems, dynamic analysis should consider the following key scenarios. To do so, EMT dynamics models of relays, inverters and the rest of the system should be used to simulate dynamic response under various fault scenarios, considering different GFL and GFM IBR control strategies and their impacts on fault characteristics relevant to relays' operation.

7.1.2.1 System Strength Variations

Explore various combinations of synchronous machines (including generators and condensers) and IBRs (incorporating different penetration levels of GFL and GFM) with the following key objectives:

- **Weak Grid Conditions:** Test relay operation in high-impedance systems to identify challenges such as distance relay underreach or delayed differential relay response.
 - Two scenarios are considered with aggregate SCR for IBRs is below 5, excluding the impact of GFMs):
 - 100% of IBRs are GFL
 - 20% of IBRs are GFM and 80% are GFL(These percentages are based on Etik Energy's other studies, which suggest that a system with up to 20% IBRs using GFM is likely to remain unstable.)
- **Strong Grid Conditions:** Validate relay performance in systems with low impedance to ensure adequate fault discrimination and coordination.
 - Strong system conditions (aggregate SCR for IBRs is at least 10, excluding the impact of GFMs) will be simulated across three different scenarios, each involving multiple dispatched GFLs:
 - System strength provided by synchronous generators only
 - System strength provided by GFM only
 - Two scenarios are considered:
 - ◆ 30% of IBRs are GFM and 70% are GFL
 - ◆ 50% of IBRs are GFM and 50% are GFL

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- System strength provided by a combination of synchronous generators and GFM
- For both weak and strong grids, it is also recommended to investigate the impact of synchronous generation retirement on steady-state and quasi-steady-state network voltages. The latter refers to voltage changes from the initial steady-state value during the fault. This analysis is crucial because relays that rely on voltage measurements may observe differences in voltage dips between the system for which their settings were initially configured and the future system. This discrepancy becomes significant when the fault occurs several busbars away from the relay's measurement point.

7.1.2.2 GFM and GFL Inverter Behaviour

- Include realistic models of GFL and GFM inverter control strategies to evaluate relay performance under different operating conditions.
 - For GFM, the investigation should include at least the two most widely used control strategies of virtual synchronous machine and droop, also accounting for the designs which use a virtual impedance/admittance control.
- Analyse the impact of proprietary IBR control algorithms on relay decision-making.
 - It is recommended to consider the following inverter types:
 - At least two different GFM control strategies as discussed above
 - GFL wind, particularly Type III wind, due to its most distinct characteristics compared to other inverter types
 - Standalone GFL BESS or solar PV
 - Hybrid BESS and solar PV
 - GFL wind or solar PV with and without a synchronous condenser

7.1.2.3 Harmonics and Interactions

- Investigate scenarios resulting in a high level of harmonics or interharmonics during the fault and analyse the effects of harmonics and interharmonics on relay algorithms, particularly for distance and differential relays.

7.1.2.4 Sequence Component Variations

- Include the following control strategies subject to model availability:
 - Deliberate provision of negative-sequence
 - Deliberate absorption of negative-sequence
 - Deliberate cancellation of negative-sequence
 - Minimal or no control of negative-sequence, as pertains to some Type III wind plants
- Simulate faults with minimal sequence components to test relays relying on these for detection.
- Model scenarios with changing sequence currents due to IBR control strategies.

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7.1.2.5 Communication System Performance

- Latency and Packet Loss: Test the impact of communication delays and data losses on POTT, differential, and distance relay coordination.

7.1.3 Incorporate Standards in Simulations

- Conduct studies with IBR plants first meeting the automatic access standards with regard to FRT requirements, and then change them all to comply with the minimum access standards, and observe instances of relay mis-operation in both cases.
- Compare NER technical requirements against worldwide requirements and identify aspects which can be included in the NER to increase the likelihood of correct operation of protection systems.
- Apply any improved aspects from these standards and Grid Codes, such as the German grid code or IEEE Std 2800-2022 requirements for negative-sequence current injection, in addition to the above, to test their feasibility and effectiveness in improving relay reliability

7.1.4 Validation Against Field Data

- Validate dynamic relay models using field data from IBR-rich grids to ensure accuracy and reliability in real-world conditions.
- Use HIL testing setups to verify relay performance under simulated fault scenarios.

By addressing these scenarios through dynamic modelling, AEMO can identify vulnerabilities in relay performance and refine protection strategies to ensure robust fault detection and isolation in evolving power systems.

8 Protection quality fault current

Table 6 proposes provisional success criteria for inverter fault-current behaviour, framed to support protection performance and comparability across OEMs. Highlighted numerical values are initial estimates only and should be treated as placeholders pending validation; there is no established international precedent for some of these thresholds.

How to read the criteria (at a glance)

1. Fault current magnitude and shape: The plant should deliver a clearly distinguishable, steady contribution for the full fault duration so relays see a strong, stable signal (for example, sustained ≥ 1.2 p.u. without fast decay or oscillation).
2. Negative-sequence content: Directional elements rely on a well-phased negative-sequence current; the current: voltage phase relationship (target 90° – 100° lead) and a typical 20–50% I_2/I_1 range should be checked via studies and may differ for GFM implementations.
3. Phase-angle stability: The fault-current phasor should remain coherent (for example, within $\pm 30^\circ$ of pre-fault), avoiding swings that would undermine angle-based protection.
4. Harmonics and transients: Keep the contribution essentially fundamental (50 Hz), with THD within relay immunity envelopes and no DC or sub-harmonic artefacts that could distort measurement.
5. Predictable impedance response: The apparent R–X trajectory should move monotonically towards the origin for forward faults (and away for reverse), without reversals or non-physical excursions that could confuse distance/impedance logic.
6. Control consistency across OEMs: Behaviour should be repeatable under equivalent conditions and not hinge on OEM-specific control nuances, enabling testability and like-for-like assessment.

Recommended next steps for the industry

- Undertake system studies to validate and, if needed, refine the proposed values.
- Cross-check the proposed criteria against current OEM capabilities.
- Assess the relative merits of:
 - pursuing rule changes to formalise these as future access standards, versus
 - incentivising their provision through new system-services mechanisms.

Note: The highlighted numbers are intended to guide study set-up and OEM engagement, not to pre-judge final thresholds. Final values should be determined through extensive simulation studies.

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Table 6 Proposed constituting components of protection quality fault current

#	Criterion	Description	Success Criterion
1	Fault Current Magnitude and Shape	Fault current must be clearly distinguishable from load current, stable in time, and consistent across events.	<ul style="list-style-type: none"> Inject ≥ 1.2 p.u. RMS for all fault types Sustain 1.2 p.u. fault current for the entire fault duration except the first 1-2 cycles, up to 220 ms (maximum magnitude variation should not exceed $\pm 10-20\%$) Avoid fast decay, ramping, or oscillatory behaviour
2	Negative-Sequence Content	Necessary to support directional protection during asymmetrical faults.	<ul style="list-style-type: none"> Current must lead the terminal negative-sequence voltage by 90°–100°. (determining the correct phase angle relationship for GFM plants requires further investigation). The negative-sequence current and voltage should have closely matched frequencies and maintain this alignment consistently throughout the fault duration. A typical target range for the negative-sequence current is 20–50% of the positive-sequence current, depending on network protection needs as determined by system studies
3	Phase Angle Stability	Maintains coherent phasor alignment for protection algorithms.	<ul style="list-style-type: none"> fault conditions, the phase angle of the fault current (Operate-current–polarising angle deviation) should remain within $\pm 30^\circ$ of its pre-fault value
4	Harmonics and Transients	Ensures the spectral content of the injected fault current supports accurate relay operation.	<ul style="list-style-type: none"> THD $\leq 8\%$ during fault contribution (IEC 60255 immunity) Inject only at fundamental frequency (e.g. 50 Hz) Avoid subharmonic, interharmonic, or DC components

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#	Criterion	Description	Success Criterion
5	Predictable Impedance Response	Fault impedance trajectory must align with physical system fault direction and support relay logic.	<ul style="list-style-type: none"> • Apparent impedance must evolve in a stable, directional, and monotonic path: <ul style="list-style-type: none"> – For forward faults, the trajectory should progress steadily toward the origin in the R-X plane (i.e., decreasing resistance and reactance), reflecting higher current and lower voltage consistent with a forward fault. – For reverse faults, the trajectory should move away from the origin (i.e., increasing R-X), consistent with fault current flowing in the reverse direction. • Unstable or non-physical impedance trajectories must be avoided throughout the entire fault duration, up to <u>220 ms</u>: The trajectory should not exhibit reversals, oscillations, or large non-monotonic excursions in impedance space that could confuse the relay logic.
6	Control Consistency Across OEMs	Ensures fault response is predictable, testable, and comparable across inverter platforms.	<ul style="list-style-type: none"> • Fault current behaviour must be repeatable under equivalent fault and network conditions • Must be independent of OEM-specific control implementations

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