Australia's National
Science Agency

Advanced Fault Response Analysis and System Integration Requirements for Inverter-Based Generation and Load Technologies

Stage 5 | Topic 1 – Inverter Design

IBR response during the fault, IBR impact on power system protection and modelling framework for Inverter-based loads

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Acknowledgement of Country

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Terminology

Below table provides list of terminology used during the work.

Abbreviation	Meaning
AC	Alternating Current
AGC	Automatic Generation Control
AEMO	Australian Energy Market Operator
BESS	Battery Energy Storage System
BTPC	Balanced Three-Phase Current
CLM	Current-Limiting Method
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	Direct Current
DFIG	Doubly-Fed Induction Generator
DOL	Direct-On-Line
DPS	Diversity Parameter Set
DFT	Discrete Fourier Transform
EMF (E*)	Internal Electromotive Force
EMT	Electromagnetic Transient (simulation/model)
ENTSO-E	European Network of Transmission System Operators for Electricity
EPRI	Electric Power Research Institute
EV	Electric Vehicle
FIDVR	Fault-Induced Delayed Voltage Recovery
FNN	Forum Netztechnik/Netzbetrieb (German grid-code body)
FRT	Fault Ride-Through
GFL	Grid-Following (inverter)
GFM	Grid-Forming (inverter)
HVDC	High Voltage Direct Current
IBL	Inverter-Based Load
IBR	Inverter-Based Resource
IEEE	Institute of Electrical and Electronics Engineers
IT	Information Technology
I_1 / V_1	Positive-Sequence Current / Voltage
I_2 / V_2	Negative-Sequence Current / Voltage
I_{max}	Maximum Converter Current
LL-G	Double Line-to-Ground (fault)
L-G / SLG	Line-to-Ground / Single Line-to-Ground (fault)
MW	Megawatt

Abbreviation	Meaning
NA	Not Applicable
NEM	National Electricity Market (Australia)
NREL	National Renewable Energy Laboratory
NS	Negative Sequence
NSCI	Negative-Sequence Current Injection
NSVC	Negative-Sequence Voltage Control
NSVI	Negative-Sequence Virtual Impedance
OEM	Original Equipment Manufacturer
P	Active Power
PDT	Phasor-Domain Transient (simulation/model)
PEM	Proton Exchange Membrane (electrolyser type)
PLL	Phase-Locked Loop
PNNL	Pacific Northwest National Laboratory
pu	Per Unit
Q	Reactive Power
R/X	Resistance-to-Reactance Ratio
RoCoF	Rate of Change of Frequency
SCR	Short-Circuit Ratio
SG	Synchronous Generator
SMIB	Single-Machine Infinite Bus
STS	Static Transfer Switch
TCR	Technical Connection Rules
TNSP	Transmission Network Service Provider
DNSP	Distribution Network Service Provider
UPS	Uninterruptible Power Supply
VAR	Volt-Ampere Reactive
VDE	Verband der Elektrotechnik (German Association for Electrical, Electronic & Information Technologies)
VFD	Variable Frequency Drive
VSM	Virtual Synchronous Machine
VUF	Voltage Unbalance Factor
WEM	Western Australia Electricity Market
Z_1,eff	Effective Positive-Sequence Impedance
Z_2,eff	Effective Negative-Sequence Impedance
50Q / 51Q / 67Q	Negative-Sequence Overcurrent and Directional Protection Elements

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Executive summary

Australia is at the forefront of the global energy transition with a rapid shift toward inverter-based resources (IBRs) such as grid-forming (GFM) and grid-following (GFL) inverters. This transition is reshaping the operational landscape of the National Electricity Market (NEM) and the Western Australia Electricity Market (WEM). This uptake has displaced traditional synchronous generators from the grid and some of the system security supports that these synchronous generators provide. The IBRs are increasingly tasked with supporting system strength, maintaining voltage stability, and providing fit-for-purpose response during the fault. Their behaviour during faults, especially in low-inertia and weak-grid environments, differs significantly from synchronous machines, challenging system stability and adequate protection operation. The industry must now grapple with how to ensure reliable protection performance in systems dominated by power electronics.

Part I: Investigation of IBR capability to suppress unbalanced faults using negative sequence current control

Part 1 of this report investigates the behaviour of inverter-based resources (IBRs), focusing on GFL and GFM inverters during negative-sequence voltage conditions. These conditions generally arise during unbalanced faults and pose challenges for control system stability and protection in grids increasingly dominated by IBRs rather than synchronous machines.

The presence of negative-sequence current is critical for accurate fault detection, particularly for protection schemes that rely on it to determine the fault direction. The phasor relationship between negative-sequence voltage and negative-sequence current is important for accurate operation of the directional relay. GFL inverters require explicit control to inject negative-sequence current, while GFM inverters could emulate voltage source behaviour to provide negative-sequence current.

> A GFL inverter relies on sophisticated control to handle unbalanced conditions. The key limitations of GFL during unbalanced condition are the current ceiling and reliance on the phased-lock loop. While GFL inverters can assist during unbalanced events, they behave more like controlled current injectors. They do not, on their own, hold up the voltage of a collapsed phase, but they contribute according to a predefined characteristic.

GFL inverters with negative-sequence control enabled have been shown to achieve the desired phase relationship between negative-sequence current and negative-sequence voltage, but remain constrained by current limits and phase-locked loop (PLL) stability. A well-tuned GFM inverter has demonstrated the ability to provide a stable, predictable phase relationship between negative-sequence current and negative-sequence voltage.

Studies of power systems to examine responses from various technologies under unbalanced conditions demonstrated a wide variety of responses. They were largely driven by control system tuning for GFL and GFM inverters. Adopting negative-sequence control during fault conditions has improved the performance of some GFL inverters.

The report presents various design targets to consider when designing the control systems for GFL or GFM inverters. A high-level summary of these design targets is provided below, while details are discussed in relevant sections of the report.

Practical design targets and recommendations are presented below as guideline principles for industry to consider and debate before finalising:

> A properly designed grid-forming (GFM) inverter operating under unbalanced conditions behaves like a voltage source, similar to a synchronous machine, positioned behind an impedance. When approaching current limits, the inverter should transition smoothly by either increasing its effective impedance or reducing its internal voltage phasor. This enables it to regulate around the maximum allowable current. Once system conditions return to normal, it should seamlessly restore full voltage control.

- During the fault negative-sequence current should lead the negative-sequence voltage by approximately 90° (± 10° tolerance)[1] to support accurate detection of the direction of the fault.
- To avoid continuous response for minor unbalances, a deadband of 2 to 3% of unbalance should be used.
- The direction of negative-sequence current should be from IBR towards the grid during the fault to reduce unbalance of the system.
- If the control system design is using k-factor approach, then the value should between 2 and 6. For a control system using a virtual impedance approach, the effective negative-sequence impedance should be close to the effective positive-sequence impedance to support phase balancing.
- Consider a proportional reduction in sequence currents or impedance fold-back to maintain voltage source behaviour during the current limiting situation.

Based on the power system study carried out, the following observations were made.

- A system with higher share of synchronous machines provides a stable and desired phasor relationship (particularly negative-sequence phasors) during the unbalanced system condition. This was as expected and aligned with the established knowledge and understanding of a system with a high share of synchronous machines.
- As inverter-based resources (IBRs) replace synchronous generation, the magnitude of negative-sequence current decreases and the phasor relationship between negative-sequence voltage and negative-sequence current deviates from the ideal 90° leading. This is more pronounced with IBRs lacking negative-sequence control.

[1] Type 3 wind generator might need larger tolerance band.

Across the scenarios studied, enabling negative-sequence control helps maintain a more stable phasor and achieve a closer-to-90° leading phase relationship. IBRs with negative-sequence control prioritise negative-sequence current output, achieving significantly higher current contribution than without negative-sequence control.

> Network studies show that as synchronous generation decreases and IBR share increases, negative-sequence control becomes essential to maintain adequate negative-sequence current magnitude and a stable ~90° leading phasor relationship between negative-sequence current and voltage.

In summary, the transition to inverter-based resources is redefining system behaviour during faults and challenging traditional protection paradigms. While synchronous generators inherently provide predictable negative-sequence support, IBRs require deliberate control strategies to achieve similar outcomes. Simulation studies confirm that well-tuned GFL and GFM inverters can meet expectations for reactive negative-sequence current injection, but performance varies widely with control design and current-limit handling. To ensure system stability and protection reliability in an IBR-rich grid, the industry should adopt standardised design targets, harmonise international requirements, and prioritise robust negative-sequence control across all technologies. These measures will enable dependable fault response, maintain voltage balance, and continue to support reliable operation of the protection systems.

Part II: Development of technical standards for grid-forming inverters with respect to impact on protection

Part II examines how the increasing penetration of inverter-based resources (IBRs), particularly grid-forming (GFM) and grid-following (GFL) inverters, is fundamentally changing power system fault behaviour and challenging the assumptions underpinning traditional protection schemes. Conventional protection systems were designed for synchronous generators that provide high-magnitude, predominantly inductive fault currents with stable and predictable sequence relationships. In contrast, IBR fault current is limited, control-dependent, and often exhibits variable magnitude and phase characteristics, particularly for negative-sequence quantities.

A central finding is that negative-sequence current behaviour is critical for protection performance. Directional relays, faulted-phase selectors, and permissive schemes depend on both sufficient magnitude and a predictable phase relationship (typically a ~90° leading angle of negative-sequence current relative to voltage). Simulation results indicate that many IBRs without explicit negative-sequence control provide insufficient or poorly phased current, resulting in delayed operation, misdirection, relay chattering, or failure to operate. These issues become more pronounced as synchronous generation is displaced and system strength declines.

GFL inverters can improve protection performance when equipped with negative-sequence control. When appropriately tuned, they can achieve near-quadrature (~90° lead) current injection and improve directional discrimination. However, performance remains constrained by current limits, PLL dynamics, and control delays. Early-cycle phasor distortion and saturation effects can still undermine relay behaviour, highlighting the need for validation using full electromagnetic transient (EMT) models.

GFM inverters can exhibit more favourable behaviour from a protection perspective when designed as voltage sources behind predominantly inductive impedance. In such designs, negative-sequence current emerges naturally with stable phasor characteristics, improving relay visibility and dependability. However, this behaviour is not inherent and it depends strongly on control design. Poorly tuned virtual impedance, excessive resistive components, or hard current clipping can degrade phasor quality and undermine protection assumptions.

IBRs equipped with well-implemented negative-sequence control significantly improve protection reliability but outcomes remain technology- and tuning-dependent.

Network-level studies confirm that protection challenges are system-wide rather than device-specific. Following outlines key observations from network-level studies:

- As IBR penetration increases, the aggregate magnitude and coherence of negative-sequence current decreases, unless a sufficient proportion of IBRs actively provide correctly phased support.
- Weak grids and high diversity in inverter behaviour increase variability in relay performance across fault types and locations.
- Enabling negative-sequence control across multiple IBRs improves overall performance but does not fully restore the robustness observed in synchronous-dominated systems.

Critically, system studies show that only well-tuned implementations (e.g., site-specific GFL with negative-sequence control or properly designed GFM systems) achieve both acceptable phasor alignment and stable current contribution.

A major design requirement for GFMs is maintaining voltage-source characteristics during current-limited operation. Abrupt current clipping can distort waveform and phasor behaviour, degrading protection performance. Instead, best practice is to:

- Smoothly increase effective impedance or reduce internal voltage (EMF) as current approaches limits,
- Maintain predictable sequence behaviour and phasor relationships, and
- Restore full voltage control promptly after the fault clears.

This “impedance fold-back” approach preserves protection-relevant characteristics while ensuring device protection.

A key outcome of Part II is the need to treat negative-sequence behaviour as a protection-critical requirement, rather than an optional control feature. Existing Australian requirements (e.g., NER) do not explicitly define key parameters such as negative-sequence current magnitude, phase angle, or current-limiting behaviour.

Drawing on international standards and study findings, the report proposes that technical requirements should include:

- Phase relationship: $\angle I_2 \approx \angle V_2 + 90°$ (±10° tolerance)
- Magnitude (k-factor): proportional injection with k ≈ 2–6
- Current limiting: coordinated, smooth reduction preserving phasor behaviour
- Voltage-source behaviour (if relevant): maintained under current limits

- Impedance symmetry: Z_2,eff ≈ Z_1,eff for GFM designs
- Response speed: fast (<20–40 ms) and sustained during fault
- Deadband: avoid response to minor unbalances (≈2–3%)

Verification should be based on EMT-grade models and consistent phasor measurement methods, ensuring accurate representation of early-cycle behaviour and limiter interactions.

In summary, reliable protection in IBR-dominated power systems requires coordinated evolution across standards, control design, modelling, and protection practice. Negative-sequence control should be universally implemented and carefully tuned, current-limiting strategies must preserve predictable behaviour, and system studies must reflect real device dynamics.

> Reliable network protection in IBR-rich power systems requires coordinated action across standards, control design, modelling, and protection practice.

Without these measures, increasing IBR penetration will lead to a progressive erosion of protection dependability posing a risk to system security. Conversely, with well-defined standards and robust implementation, GFM and GFL inverters can provide protection-compatible fault response and support reliable operation of future power systems.

Part III: IBL Interface specification for model structure and performance mapping

Part 3 of this report establishes a technology-neutral, modular modelling framework for inverter-based loads (IBLs), enabling consistent and credible representation of their behaviour in both phasor-domain transient (PDT) and electromagnetic transient (EMT) simulations. Modern IBL, such as data centres, electrolysers, EV fast chargers, and industrial drive systems, are increasingly dominated by power electronics and supervisory logic, leading to complex disturbance responses and recovery behaviours that are not captured by traditional static load models. Part 3 addresses this gap by focusing on externally observable behaviour at the point of connection, rather than internal vendor-specific design details, ensuring model applicability across diverse technologies and confidentiality requirements.

IBLs commonly include AC–DC converters, DC-link energy buffers, inverter stages, embedded storage elements, auxiliary systems, and supervisory control. These elements interact dynamically, shaping behaviours such as current-limited near-constant power response during voltage depressions, momentary cessation, conditional transfer to internal supply, successive-disturbance tolerance, unbalance and phase-angle sensitivity, and staged reconnection and recovery. These behaviours influence voltage recovery, frequency stability, system strength margins, and interaction risks in weak or converter-dense networks. Part 3 maps these behaviours to specific modules and defines the minimum modelling features needed to reproduce them credibly in system studies.

The modular interface specification provides a standardised module inventory, a set of required inputs/outputs, and a small number of retained internal states, timers, and flags, enabling consistent implementation across PDT and EMT domains. Key cross-cutting modules such as supervisory logic and protection/limit logic are explicitly represented so that conditional state-dependent behaviours, transfer and reconnection logic, and “second-event” recovery effects are accurately modelled. EMT models are used to benchmark fast dynamics, limits, and transitions, while PDT abstractions reproduce the resulting connection-point response envelopes for wide-area studies.

The framework also introduces a Diversity Parameter Set (DPS) to support multi-site and fleet studies, recognising that timing differences and behavioural coherence across facilities can materially affect system outcomes. Diversity can be represented through bounded parameter ranges, scenario ensembles, or stochastic sampling, without needing sensitive OEM details. Validation is structured through an evidence hierarchy comprising in-service disturbance replay, factory and integration evidence, EMT benchmarking, and engineering reasonableness checks, with confidence levels assigned per key behaviour group.

Part 3 provides a scalable, vendor independent modelling foundation that reflects the real drivers of IBL disturbance and recovery behaviour. It is intended to support credible assessment and validation of IBL impacts across network conditions, and provides the basis for future guidance and coordination frameworks without imposing prescriptive performance requirements.

1 Background and Introduction

Inverter-based resources (IBRs), including grid-forming (GFM) and grid-following (GFL) inverters, are increasingly relied upon to support system strength, maintain voltage stability, and respond to faults. Their fault behaviour in low-inertia, weak-grid environments differs markedly from that of synchronous machines. This poses challenges to system stability and protection schemes.

At the same time, inverter-based loads (IBLs) such as data centres, EV chargers, electrolysers, and industrial drives are becoming major contributors to system dynamics. These loads feature complex power electronic interfaces with some similarities but often with more differences from IBRs. Current modelling frameworks lack the modularity and performance integration needed to accurately simulate their response to disturbances and assess their impact on the grid.

Previous work completed by researchers through various stages examined how large signal stability can be improved by appropriate inverter tuning, the impact of various control system approaches and their impact on large-signal stability and proposed design and tuning criteria. Complementing the work completed in previous stages, this stage 5 of the research focuses on the three emerging needs in the realm of converter control design. They are:

- Task 1: Typical IBR responses during faults

Unlike synchronous machines, IBRs can flexibly control their interaction with negative-sequence conditions during unbalanced faults. This work investigates how GFL and GFM inverters behave under such conditions. The work aims to identify which control behaviours support faster and more stable voltage recovery, better protection coordination, and future standardisation.

- Task 2: Technical standards for GFM accounting for impact on protection systems

The GFM inverters behave as voltage sources behind impedance and exhibit nonlinear behaviour during faults and post-fault recovery. This behaviour can impact power system protection schemes. Using detailed modelling, this work examines the risks of mis-operation of protection schemes and develops technical recommendations.

- Task 3: Modular interface specification and modelling framework for IBLs

The growing diversity of IBLs (e.g. data centres, EV chargers, electrolysers) demands a flexible, scalable modelling structure that can accommodate varying technologies and control schemes. The focus of this work is to develop a modular interface specification and modelling framework for IBLs which is applicable for system studies.

1.1 Progress against the Roadmap

The Roadmap Topic 1 focuses on development of capabilities, services, design methodologies and standards for Inverter-Based Resources (IBRs) to ensure power system reliability.

Stage 1 created a research roadmap addressing key questions on IBR control, services, capabilities, and protection, engaging stakeholders like universities, governments, and CSIRO. It outlined five major tasks plus shared tasks with other research topics. Stage 2 developed a practical tool to evaluate multi-IBR system stability, introducing indices for quick transient stability margin assessment. Stage 3 focused on grid-forming inverter design and control to enhance reliability in IBR-dominated grids. Stage 4 analysed the sensitivity of control parameters and improved large-signal stability tools, offering practical tuning and design guidelines.

Stages 1 to 4 focused on the IBR control design to support stable operation of the power system and improvement of transient stability margin, while giving no consideration to either IBL control design or IBR during the fault behaviour and its impact on the system and protection. This gap is being addressed in stage 5.

The Stage 5 work completed aligns well with the Roadmap for Topic 1. Specifically, the following roadmap areas are being investigated through the stage 5 work:

- Typical IBR responses during faults: This work focuses on the interrelationship between IBR and the power system protection system, where it examines the impacts of various control approaches on power system protection adequacy.
- Technical standards for GFM accounting for impact on protection systems: This task builds on the learnings from the previous talk to support revision (if needed) of Technical Standards in Australia.
- Modelling framework for IBLs: The aim of this task is to develop bespoke models of IBLs and a modelling framework for IBRs that support system studies.

Table below shows the Research Roadmap tasks being addressed by Stage-5 research activities

Table 1 Progress against Topic 1 Research Roadmap

Roadmap Major Tasks	Roadmap Tasks	Stage 5 Tasks	Progress*
4. Protection and Reliability	4.1 IBRs effect on existing protection systems	Typical IBR responses during faults Technical standards for GFM accounting for impact on protection systems	85%
	4.2 Enhancing IBR response during and subsequent to faults		85%
	4.3 Assessment and enhancement of IBRs reliability		90%
4. Protection and Reliability	4.3 Assessment and enhancement of IBRs reliability	Modelling framework for IBLs	60%

*Progress to date against roadmap tasks.

1.2 Research relevance to Australia

Australia is at the forefront of the global energy transition, with a rapid shift toward inverter-based resources (IBRs) such as grid-forming (GFM) and grid-following (GFL) inverters. This transition is reshaping the operational landscape of the National Electricity Market (NEM) and the Western Australia Electricity Market (WEM). This uptake has displaced traditional synchronous generators from the grid and some of the system security supports that these synchronous generators provide. The IBRs are increasingly tasked with supporting system strength, maintaining voltage stability, and providing a fit-for-purpose response during the fault. Their behaviour during faults, especially in low-inertia and weak-grid environments, differs significantly from synchronous machines, challenging system stability and adequate protection operation. An inappropriate behaviour during the fault could see a rise in un-faulted phase voltages, leading to undesired consequences to the grid. The industry must now grapple with how to ensure reliable protection performance in systems dominated by power electronics.

Recently, AEMO has issued a Statement of Need under clause 3.11.12(a) of the National Electricity Rules to acquire Type 2 transitional services for the purpose of conducting a Grid-Forming (GFM) Inverter Protection-Quality Fault Current Trial. The trial aims to demonstrate whether GFM inverters can provide fault current of sufficient magnitude, duration, and composition (e.g. relevant positive and negative-sequence components and waveform properties) for protection relays to operate correctly under diverse system operation and fault conditions.

AEMO recently published two reports that highlight investigating IBRs to provide protection against quality fault current [1]. Both reports highlighted several system incidents that identified that traditional protection systems are not well-suited to the quality of fault current supplied by the IBRs. These reports recommended enhancing modelling and simulation practices to study the 'composition' of the fault current contribution from IBRs.

Currently, a key unresolved issue is whether IBRs can reliably provide minimum system strength, particularly in terms of protection adequacy. Before revising grid-codes to include IBRs as providers of protection-quality fault current, it is essential to understand their capabilities and limitations. The research conducted under Stage 5, Topic 1, is highly relevant to this effort. By simulating the fault response of GFL and GFM inverters and evaluating their ability to provide "protection-quality fault current," the project addresses a key technical barrier to broader IBR adoption. These simulations are grounded in technologies currently deployed in the NEM and WEM, ensuring that the findings are directly applicable to real-world Australian grid conditions. For Australian industry stakeholders, transmission network service providers (TNSPs), distribution network service providers (DNSPs), inverter manufacturers, and renewable energy developers, this research offers actionable insights. The models being developed to investigate IBR response during the fault are similar to the technologies present in the National Electricity Market (NEM) and Western Australia Electricity Market (WEM). Therefore, the learning outcomes would provide useful information on the interrelationship between IBRs and protection in the context of the NEM and the WEM.

Australia's electricity system is seeing rapid growth in large, non-traditional, inverter-based loads, with some proposed facilities reaching several hundred megawatts to over one gigawatt. These inverter-based loads can either support or challenge stability depending on their controls and how they interact with the network. At present, fit-for-purpose dynamic models are generally not available. International practice still leans on simplified composite load representations that do not capture key internal controls, protection behaviour, or dynamic interactions, which can mask vulnerabilities such as unexpected tripping, adverse interactions, and oscillatory instability, particularly in low system strength conditions. International incidents involving data centre disturbances reinforce the need to improve modelling. Australia, therefore, needs a scalable, high-fidelity modelling framework that defines what to represent, at what level of detail, and for which study types, without adding complexity where it is not justified. This report addresses this gap by proposing a modular, technology-neutral modelling framework that captures externally observable behaviour at the point of connection. This enables consistent and credible representation of IBL impacts across both EMT and phasor-domain studies. The framework supports improved assessment of system stability, protection interactions, and recovery performance in evolving power systems.

Furthermore, excluding any confidential or sensitive data used, the EMT models developed will be released to CSIRO to share with the research community to scrutinise, change, grow, or otherwise use as they see fit. Furthermore, by releasing the EMT models to CSIRO for broader use, the research fosters collaboration and innovation across the national research and engineering community.

Part I Typical IBR responses during faults

2 Behaviour of Grid-following and Grid-Forming Inverters Under Negative-Sequence Voltage Conditions

2.1 Objective and scope

he objective of Task 1 (Part I) is to characterise how grid-following (GFL) and grid-forming (GFM) inverter-based resources (IBRs) respond to negative-sequence voltage conditions during unbalanced faults, and to identify the control behaviours that support stable voltage recovery, dependable protection coordination, and future standardisation. Unlike synchronous machines, whose negative-sequence response is governed by machine physics, IBRs manage negative-sequence quantities entirely through their control systems. Part I therefore examines what behaviour is achievable, how it varies with control design, and how closely it can emulate the predictable response that protection schemes have historically relied upon.

Part I is intended to be used as a reference baseline that links inverter control behaviour to the negative-sequence quantities that matter for system protection and voltage balance. It establishes the physical meaning of negative-sequence components, sets out the notation and phasor conventions used throughout the report, and defines the attributes against which each technology is assessed.

The scope covers a representative range of real and generic technologies, including generic and site-specific GFL battery energy storage systems (BESS), Type 3 and Type 4 wind farms, generic and site-specific GFM BESS, and GFM solar in droop and virtual synchronous machine (VSM) configurations. Most technologies are assessed both with and without negative-sequence control enabled, so that the contribution of explicit negative-sequence control can be isolated. Part I explains the physical meaning and impact of negative-sequence components, examines how GFL and GFM inverters respond to negative-sequence voltage conditions, and integrates guidance from major standards ([2], [3], [4]) and research ([5], [6], [7]).

Part I does not define access standards, compliance criteria, or mandatory performance limits, nor does it endorse any particular technology or vendor. Results are derived from existing models using their native control systems and are presented for comparative illustration only. Instead, Part I provides:

- an explanation of negative-sequence behaviour and its significance for stability and protection,
- a comparative assessment of GFL and GFM responses under unbalanced conditions, and
- a set of practical, quantified design targets (covering phase angle, deadband, current direction, magnitude/k-factor, impedance symmetry, response speed, and current-limiting behaviour) offered as guideline principles for industry consideration and debate.

Collectively, Part I provides the technical evidence base and design vocabulary that inform the protection-focused standards work in Part II.

2.2 Negative-sequence voltages and currents: meaning and Impact

In a three-phase system, any imbalance can be decomposed via symmetrical components into a positive-sequence (balanced set of voltages/currents with normal phase rotation), a negative-sequence (balanced set with reversed rotation), and possibly a zero-sequence (in-phase components), as shown in Figure 1. Negative-sequence voltage (V_2) indicates an imbalance where one or two phase voltages deviate in magnitude or phase. Common causes include single-phase faults, open conductors, or unbalanced loads. The negative-sequence voltage at a node drives a negative-sequence current through the network's negative-sequence impedance. For single-line-to-ground faults, the zero-sequence network availability, set primarily by transformer winding connections, grounding method, and any earthing transformer, strongly affects fault current magnitude and relay observability. This section focuses on negative-sequence behaviour (V_2/I_2), but protection outcomes depend on the combined positive-, negative-, and zero-sequence networks [8].

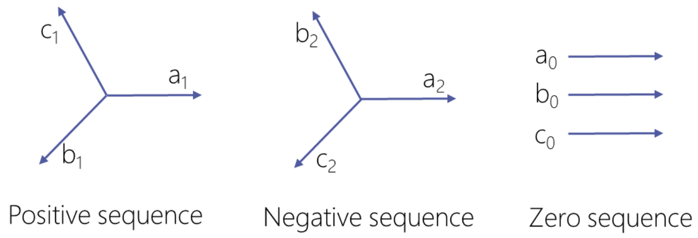

Figure 1 Sequence components

Synchronous generators (SGs) have a well-defined negative-sequence impedance (often on the order of the sub-transient reactance), so they will source a substantial negative-sequence current (I_2) during unbalanced system conditions. Critically, in an SG, this I_2 is predominantly reactive (approximately 90° in quadrature with V_2) due to the inductive nature of the machine's negative-sequence impedance, and this phase relationship remains stable during the fault, as illustrated in Figure 2. In this report, $I_2$is defined as positive from the device to the grid. For an approximately zero internal negative-sequence EMF, $I_2 = (0 - V_2)/jX_2$, so $I_2$is in quadrature with V_2(leading by approximately 90° for inductive X_2). For the intended predominantly reactive I_2 response, average negative-sequence real power is near zero. However, under unbalance the instantaneous three-phase power contains a pronounced 2ω component, which drives torque ripple and additional heating in machines. The heating mechanism is primarily I_2^2R loss in stator and rotor circuits. Many grid codes specify maximum steady-state I_2 as a percentage of rated current. Rotating-machine withstand limits for negative-sequence are typically specified in machine standards rather than as a single universal value in the European grid-code legal text. For example, IEC 60034-1 specifies continuous unbalanced operating capability for synchronous machines in terms of an allowable negative-sequence current ratio I_2/I_N (typically 0.05–0.10 pu, depending on machine type and cooling), and also specifies an I_2^2t style short-duration capability for fault conditions. European requirements do, however, explicitly recognise 'asymmetric load (negative phase sequence)' as a protection and coordination consideration for power-generating modules.

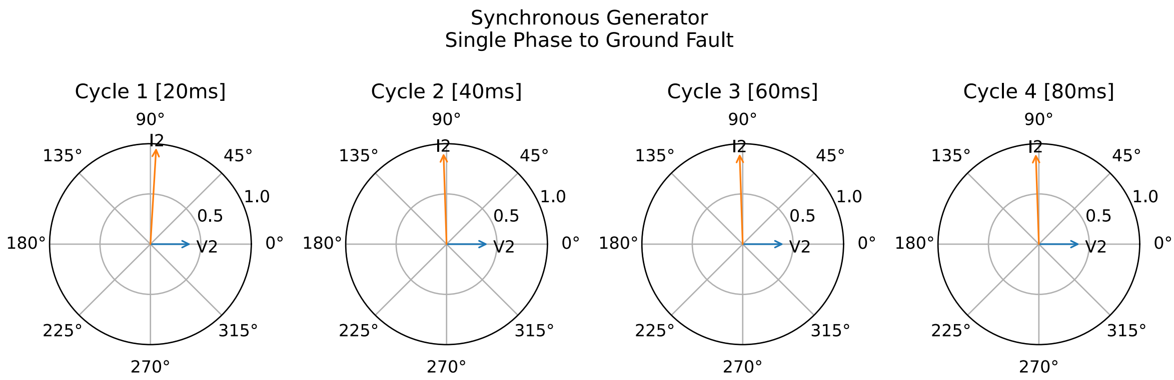

Figure 2 Negative-sequence components of a synchronous generator during single line to ground fault

For the power system, negative-sequence components affect both stability and protection. During an unbalanced fault, positive-sequence reactive current injection (as required for voltage support) will raise voltage on all phases uniformly, which can cause overvoltages on the healthy phases if negative-sequence current is not also provided. Negative-sequence current injection, on the other hand, addresses the imbalance explicitly. The intent is to boost the faulted phase voltages and mitigate overvoltage in unfaulted phases by countering the negative-sequence voltage at the point of connection.

From a protection standpoint, relay functions such as negative-sequence overcurrent (50Q/51Q), negative-sequence directional elements (67Q), and faulted phase selectors rely on the presence of sufficient I_2 with a predictable phase angle relative to V_2. For SLG faults in particular, sensitivity can be dominated by the available zero-sequence path and transformer connection, even if I_2 control is well behaved. Traditional relays assume that during faults, I_2 will be sizable and roughly in quadrature (90°) with V_2, as is true for SGs, as shown in Figure 3. If modern inverters do not contribute adequate I_2 or if their I_2 has an unexpected phase angle, protection can misoperate or fail to detect/unambiguously locate faults. In summary, negative-sequence voltage is an indicator of imbalance, and controlled negative-sequence current responses are needed to support voltage symmetry and maintain protection coordination.

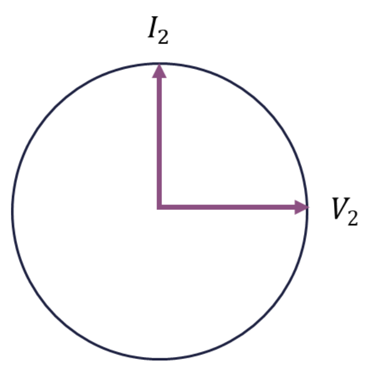

Figure 3 Intended relationship between V_2 and I_2 during unbalanced fault

Most converter hardware has a hard current ceiling, so regardless of whether it is operated in Grid-Following (current-source) or Grid-Forming (voltage-source behind impedance) mode, its fault and negative-sequence contribution is bounded by $I_{\max}$. Therefore, even if a negative-sequence current is requested, the achievable I_2 is constrained by the inverter rating and any simultaneous positive-sequence current obligations. As an illustrative example, consider a 100 MVA synchronous generator with 14% sub-transient reactance connected through a transformer with 8% leakage reactance. A line-to-line fault close to the connection transformer results in 40% negative-sequence voltage. Under such conditions, the negative-sequence current present in the system would be 181%. By contrast, a 100 MVA IBR with $I_{\max} = 1.2$ pu has limited headroom. If it attempts to maintain 1.0 pu pre-fault current (active-priority), only ~0.2 pu incremental capacity remains for negative-sequence support. In reactive-priority operation, active current can be curtailed to free additional headroom for $I_1$and I_2 support, subject to the same phase-current ceiling.

2.3 GFL inverter response to negative-sequence conditions

2.3.1 Principles of response

GFL inverters operate as current sources synchronised to the grid voltage via a PLL. In their simplest form, they inject only positive-sequence current to track active and reactive power setpoints, ignoring negative-sequence voltages resulting from unbalanced conditions. This minimises stress on the converter, but leaves imbalances of the grid unmitigated.

Modern grid codes [2], [3], however, require IBRs to provide negative-sequence current during unbalanced conditions. To meet this, GFLs must generate current references for both positive- and negative-sequences, typically proportional to the measured V_1 and V_2. The outcome is that a GFL contributes negative-sequence current support only when explicitly commanded by its control, rather than inherently as part of its physics.

2.3.2 Control techniques for negative-sequence response

The only possible approach to control the negative-sequence response in the GFL is through the control system. The dominant method is dual synchronous reference frame (SRF) control [9] [10], where measured voltages are decomposed into positive and negative sequences. One SRF rotates forward at the grid frequency to capture the positive sequence, while another rotates backwards to capture the negative sequence. Each has its own current controller, allowing the GFL to generate independent current references for I_1 and I_2 during unbalanced conditions.

Some existing approaches for handling the negative-sequence component in GFL inverters are shown in Table 2.

Table 2 Typical approaches for negative-sequence management in GFL inverters

Approach	Details
Legacy designs	Only positive-sequence current is injected. Unbalanced conditions uncorrected.
Modern implementations	Provides negative-sequence support. Use of dual synchronous reference frame loops to meet the grid code.
Advanced schemes	Support during deep unbalanced conditions using filtering or adaptive PLLs.

There are some practical challenges associated with the fast and accurate performance of the control system, which are summarised in Table 3, while details are presented in Section 2.3.5.

Table 3 Challenges of fast and accurate performance

Challenge	Details
Sequence extraction	Use of digital filters or moving DFTs can introduce ~1 cycle delay. Note that IEEE 2800 conformity assessment defines the phasor/sequence measurement using a one-cycle DFT moving window, and the associated measurement delay is included in the response and settling times.
Controller tuning	Demanding control tuning as the negative-sequence loop operates at twice the grid frequency. Control interaction with the positive-sequence loop is a possibility.
Control system coordination	All control loops (e.g. positive-sequence, negative-sequence, DC link control, etc.) are to be carefully balanced for speed, accuracy, and robustness to noise. Poor tuning risks sluggish or oscillatory response during unbalanced conditions.

2.3.3 Negative-sequence current and phase relation

Grid codes sometimes specify that negative-sequence reactive current must be injected in proportion to the measured negative-sequence voltage magnitude $|V_2|$, and in quadrature (≈90° lead) with V_2 as shown in Figure 4 [2] [3].

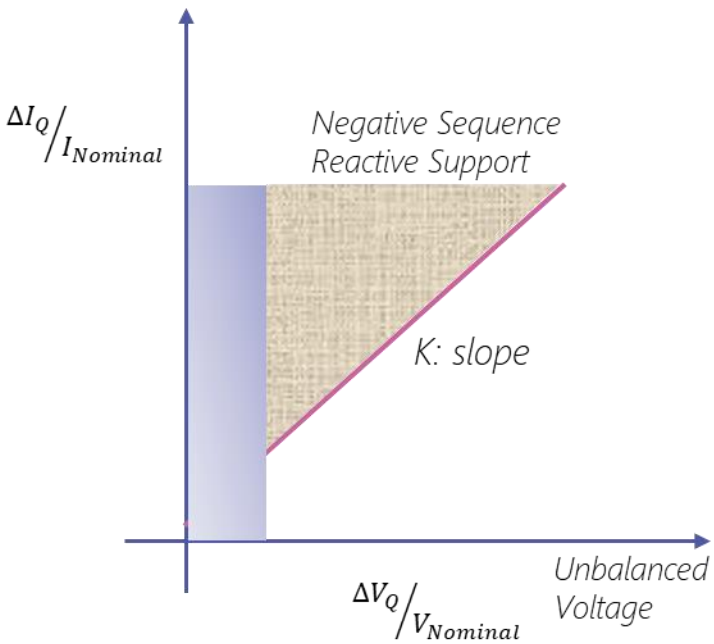

Figure 4 Typical relationship between V_2 and I_2

A proportionality constant (the k-factor) is often used to define the slope of injection as follows.

$$\Delta I_Q = k\Delta V$$

For unbalanced dips, the commanded negative-sequence current magnitude is:

$$|I_2| = k|V_2|$$

This ensures that the increment of reactive current in the positive and negative sequences is proportional to the depth of the voltage dip.

Negative-sequence phasor relation

The negative-sequence current is commanded 90° out of phase with V_2, making it purely reactive.

In a reference frame aligned with V_2:

$i_{2d} = 0 \qquad i_{2q} = +k\,|V_2|$

where the sign is chosen so that i_{2q} leads V_2 (leading, predominantly reactive negative-sequence current). This produces reactive negative-sequence support without active negative-sequence power.

Effective reactance analogy

Using these control laws, a GFL inverter actively contributes negative-sequence current during unbalanced events. This behaviour mimics a synchronous generator's negative-sequence reactance:

$Z_2^{eff} = \frac{1}{k}$

For typical k-values in the range 2–6, the inverter presents an effective negative-sequence reactance of 0.5–0.167 pu, comparable to conventional synchronous machines, but with current limitation enforced by the inverter's protection.

Phase angle

The phase relationship between I_2 and V_2 is crucial. GFL control targets a 90° lead (purely reactive I_2). For instance, if the inverter detects a negative-sequence voltage at its terminal, it will command a current that *leads* that V_2 by ~90°. In practical implementation, achieving exactly 90° may be difficult, so standards allow a tolerance (IEEE 2800 permits 90–100° lead for full converters, acknowledging minimal resistive errors). This explicit enforcement of phase via control can be seen as a strength, since it ensures tight compliance with standards (90–100°) even when grid impedance is not purely inductive. This 90° rule ensures the inverter is not injecting negative-sequence active power (which would cause internal DC bus oscillations and exacerbate torque oscillations in any nearby machines). Instead, the inverter supplies predominantly reactive negative-sequence current, so average negative-sequence real power is near zero, but instantaneous power still contains a 2ω oscillation (100 Hz in a 50 Hz system), which can drive the DC-link ripple.

An important nuance is the current priority and limitation. During a large fault, the inverter's total current is limited by hardware (often ~1.1–1.5 pu short-term). The control system must allocate this limited current between positive-sequence components (needed to support the overall voltage and active power) and negative-sequence components (to balance the phases). Most grid codes generally prioritise voltage support and ride-through, meaning *positive-sequence support tends to take precedence* when current saturates. However, they may also require that both sequences be reduced proportionally to stay within the limit, while maintaining the requisite phase angle relationship. In practice, a vector current limit is imposed.

2.3.4 Current limitations and prioritisation

Combined current limit

The inverter ensures that the vector sum of positive and negative-sequence currents does not exceed I_{max} . A simplified criterion is

$$|I_1|^2 + |I_2|^2 \leq I_{max}^2$$

meaning the RMS of the combined positive and negative sequence currents stay within the capability. More conservatively, some implementations ensure no *phase* current exceeds the limit, which roughly corresponds to the worst case of:

$$|I_1| + |I_2| \leq I_{max}$$

Note: This sequence-magnitude criterion is only a proxy. Depending on the relative angles of I_1 and I_2, it can still produce a phase current that exceeds $I_{\max}$, so per-phase instantaneous checks (reconstructed i_a, i_b, i_c) should be used for compliance and protection of the converter.

In practice, compliance is usually enforced on per-phase instantaneous current, so the limiter should reconstruct phase currents from I_1 and I_2 and check $|\ i_a\ |$, $|\ i_b\ |$, and $|\ i_c\ |$, not only sequence magnitudes.

Proportional sequence reduction

If the reference currents calculated by the controller would cause I_{max} to be exceeded, the GFL will scale back both I_1 and I_2 proportionally. For example, one can compute a scaling factor.

Scaling factor:

$$\propto = \min\left(1, \frac{I_{max}}{\sqrt{\left|I_1^{ref}\right|^2 + \left|I_2^{ref}\right|^2}}\right)$$

Apply to both sequences:

$$I_1^{cmd} = \propto I_1^{ref} \qquad I_2^{cmd} = \propto I_2^{ref}$$

Both sequences “back off” together, preserving their ratio and phase relation. This ensures the inverter doesn’t simply drop all I_2 (which would unbalance the output current), and it maintains support in all sequence components as far as possible. Notably, IEEE 2800 allows one to choose active-current priority or reactive-current priority during faults. In a *reactive-priority* mode (typical for low-voltage ride-through), the inverter will sacrifice active power output to feed reactive currents (both I_1 and I_2) up to the limit. In an *active-priority* mode (e.g. some energy storage systems), it might do the opposite. In either case, if reactive current is prioritised, positive-sequence reactive support is usually the highest priority, with negative-sequence support using the remaining capacity.

2.3.5 System stability implications

During faulted or unbalanced conditions, a well-controlled GFL inverter will inject both positive- and negative-sequence currents up to its current limit. As a current source, once this ceiling is reached, it cannot increase output, and its terminal voltage may collapse under a severe fault. Within its limit, the control system allocates current according to defined priorities; most grid codes call for reactive support first. Negative-sequence current contributes by supplying additional current into the faulted phase(s) while reducing overvoltage in the healthy phase(s), improving balance compared with injecting only positive-sequence current.

A critical stability challenge lies in the PLL. Conventional PLLs, when locked to a phase voltage, are disturbed by the 2× frequency oscillations introduced by negative-sequence components. This can destabilise angle estimation during faults and distort current references. To counteract this, many designs use positive-sequence PLLs (e.g. decoupled double synchronous PLLs) or filtering schemes to suppress the 100 Hz ripple. Without such measures, GFLs risk oscillatory synchronisation. Even with ideal sequence references, practical implementations exhibit inter-sequence coupling through PLL dynamics, current-limiter nonlinearities, and DC-link control, so compliance should be verified using the full closed-loop model rather than the sequence blocks in isolation.

The DC bus is another source of vulnerability. Even when the commanded negative-sequence current is reactive, the instantaneous three-phase power exhibits a double-frequency oscillation that introduces a second-harmonic ripple in the DC-link voltage. This can stress capacitors and destabilise the DC regulator. Stable operation, therefore, depends on robust inner-loop dynamics and often auxiliary measures such as notch filters or feed-forward cancellation to prevent these oscillations from feeding back into the current controller.

Tuning the negative-sequence controller adds further complexity. Operating at the beat frequency (e.g. 100 Hz in a 50 Hz system) makes the loop more sensitive to delays and cross-coupling with the positive-sequence control. Insufficient phase margin or poorly coordinated bandwidths can result in oscillatory or sluggish behaviour, undermining grid-code compliance for rapid negative-sequence injection.

From a broader power system perspective, the limited fault current capability of GFL inverters (typically 1.1–1.5 pu, versus 2–3 pu for synchronous machines) means their absolute negative-sequence contribution is small. Published studies report that some inverter controls can deliver relatively small $|I_2|$ during deep unbalanced faults unless negative-sequence control is explicitly enabled and prioritised; reported values vary with control design, current limits, and study conditions. Consequently, residual negative-sequence voltages remain higher in inverter-dominated systems, placing stress on equipment and complicating protection settings. That said, enabling negative-sequence support improves relay performance. In practice, the achievable I_2 magnitude is determined not just by this ceiling but also by the allocation strategy. For example, reactive-priority settings can allocate most of the available current to positive-sequence and negative-sequence reactive support, yielding much stronger system contribution.

In summary, the stability of GFL under unbalanced conditions depends heavily on PLL synchronisation, DC-bus energy balance, and careful tuning of current controllers. With appropriate design, these inverters can provide useful negative-sequence support and ride through faults stably. However, their contribution remains constrained by current limits and is more fragile than that of synchronous machines or well-designed GFMs.

2.3.6 Steady-state considerations

In steady-state operation with small voltage or load unbalances (typically a few per cent V_2), GFL inverters usually continue to supply primarily positive-sequence current and only contribute negative-sequence current if the imbalance exceeds a defined threshold. Many controllers apply a deadband to prevent continuous response to trivial deviations, thereby avoiding unnecessary oscillations and limiting the double-frequency ripple on the DC bus. This approach improves thermal robustness and long-term stability of the converter. Importantly, both technologies manage continuous negative-sequence duty, but in different ways. A GFL inverter can apply a deadband so it does not intentionally inject I_2 under a small steady-state unbalance, whereas a synchronous machine will naturally carry I_2 whenever $V_2 \neq 0$and can only manage this via withstand limits and protection (for example I_2 thresholds and $I_2^2 t$ thermal tripping). As a result, GFLs do not act as continuous balancing resources for minor imbalances, but once thresholds are exceeded, their collective contributions, when many units follow the same grid code, play a significant role in restoring acceptable voltage balance across the system.

2.3.7 Practical design targets

Table 4 provides practical design targets for the GFL inverter.

Table 4 Practical design targets for GFL inverter

Attribute	Practical design targets
Phase relationship	$\angle(I_2) \approx \angle(V_2)$ + 90° (reactive injection) Some standards allow 90° - 100° tolerance.
Slope (k – equivalent)	Suitable k ≈ 2–6 which results in $X_{2,eff}$ ≈ 0.5 – 0.167 pu)
Symmetry	Maintain consistent treatment of positive- and negative-sequence currents (e.g. proportional scaling under current limit)
R/X and loop tuning	Negative-sequence loop operates at 2× frequency Coordination with the positive-sequence control loop is required to maintain overall control system stability
Limits	Regulate near 95 – 100% of I_{max} Apply proportional reduction to I_1 and I_2 if exceeded.
Sharing/priority	Implement current allocation consistent with international standards (typically prioritise positive-sequence reactive support, with negative-sequence using residual headroom)
Steady-state behaviour / deadband	Apply deadbands/thresholds so that minor unbalances (<~2–3% V_2) do not trigger continuous I_2 injection

2.3.8 Summary

A GFL inverter relies on sophisticated control to handle unbalanced conditions. With decoupled sequence control, it can inject negative-sequence reactive current (approximately in quadrature with the negative-sequence voltage) proportional to the voltage unbalance (k-factor slope). Stability-wise, as long as the PLL and current loops are properly tuned, the GFL can ride through unbalanced faults, albeit with limited current magnitude. It will likely reduce both positive-sequence and negative-sequence currents if limits are reached, typically prioritising critical support (voltage support via reactive current) first. The main limitations of GFL during unbalanced conditions are the current ceiling and reliance on the PLL. These factors mean that while GFL inverters can *assist* during unbalanced events, they behave more like controlled current injectors.

They do not, on their own, hold up the voltage of a collapsed phase, but they contribute according to a predefined characteristic.

2.4 GFM inverter response to negative-sequence conditions

2.4.1 Principles of response

GFM inverters operate as controlled voltage sources, setting their own frequency and voltage (either absolutely or relative to the grid) within their capacity. A GFM inverter attempts to maintain balanced, stable three-phase voltages at its terminals, much like a synchronous generator would. Under balanced conditions, GFMs regulate to a setpoint (using droop, dispatchable virtual oscillator, or other GFM control) to share load and maintain system frequency/voltage.

The challenge comes when the grid or load becomes unbalanced: an ideal voltage source would inject whatever current is needed to keep each phase at the reference voltage, which could result in very large negative-sequence currents flowing during faults or asymmetries. To prevent overcurrent and to behave in a predictable manner, GFM inverters incorporate a virtual impedance or other sequence-balancing control in their design.

The VDE FNN (2025) guidance for GFM units prescribes that a GFM unit should behave as a Thevenin-equivalent voltage source behind an impedance [4]. It highlights that "the effective negative-sequence system impedance should generally be equal to the effective positive-sequence system impedance during normal operation". In other words, the inverter should present a similar impedance to negative-sequence currents as it does to positive-sequence. If a GFM has, say, a 0.2 pu positive-sequence output impedance for droop control, it should also appear to have ~0.2 pu negative-sequence impedance in the negative-sequence network. This ensures it shares unbalanced currents in proportion to its capacity, just as it would share a balanced load. To implement this, GFM control may actively insert a virtual negative-sequence impedance, $Z_{2,eff}$ as follows.

$$I_2 = \frac{V_{int,2} - V_2}{Z_{2,eff}}$$

where $V_{int,2}$ is the internal negative-sequence voltage source of the inverter (including any virtual terms).

In normal operation (the GFM's internal voltage is balanced), so this simplifies to

$$I_2 \approx -\frac{V_2}{Z_{2,eff}}$$

Thus, the GFM injects a negative-sequence current proportional to the negative-sequence voltage at its terminals, with an effective admittance $1/Z_{2,eff}$. By choosing $Z_{2,eff}$ equal to the positive-sequence impedance (largely inductive), the negative-sequence current will be predominantly reactive and of the appropriate magnitude. For instance, if $Z_1 = Z_2 = j0.25\ pu$, a $V_2 = 0.1\ pu$=0.1 pu would cause $I_2 \approx 0.4\ pu$, closely emulating an SG's response.

Many GFMs don't compute an internal negative-sequence source every cycle. Instead, they add a negative-sequence droop / virtual-impedance loop so the inverter looks like a voltage source behind a designed negative-sequence Thevenin impedance Z_2, virtual.

One simple method is to inject a voltage drop in the reference proportional to the measured negative-sequence current:

$$V^*_{neg,\ ref} = V^*_{neg,\ open} + V^*_{neg,\ comp}$$

$$V^*_{neg,\ comp} = -Z_{2,\ virt}\ I_{2,\ meas}$$

This compensating voltage component is added to the reference voltage in opposite phase to counteract I_2. This effectively yields a Thevenin impedance $Z_{2,\ virt}$ for the negative-sequence (the explicit controller-inserted part) network.

VDE-FNN notes that negative-sequence voltage at the terminals is permissible if it helps keep the terminal voltage as symmetrical as possible or limits continuous asymmetric currents. A small intentional internal imbalance can therefore be acceptable to reduce persistent I_2 (>~3% of rated current), while under faults, the GFM still behaves like a source behind impedance until it nears its current limit.

2.4.2 Control techniques for negative-sequence response

Not all GFMs are controlled identically. The technique materially affects I_2 magnitude, phase, sharing, and behaviour at limits.

Most FRT-capable implementations (GFM and GFL) are organised as a Positive/Negative Sequence Control (PNSC) stack: (i) sequence extraction (+/−), (ii) positive-sequence voltage control (droop/VSM) with current-limit coordination, (iii) a negative-sequence path (NSVI/NSVC/NSCI/BTPV/BTPC) to shape I_2/V_2, and (iv) a current-limiting method (CLM) that reconciles the positive/negative commands with phase-current limits. The subsections below describe the negative-sequence options and how they interact with the limiter.

"Plain" voltage-source GFM (no explicit unbalance control)

- Objective: The objective is to hold balanced phase voltages using droop/VSM without sequence separation.
- Consequence: Under a significant imbalance, the unit can drive (produce) very large, effectively uncontrolled I_2 until it hits the current limit. The phase may deviate from 90° if dynamics or resistive effects intrude and, in some cases, the response can appear mis-phased, including undesirable absorption of negative-sequence VARs.
- Risk: The risk is unnecessary stress (2× frequency oscillations, heating) on inverter and potential non-compliance with "reactive-only" intent.

Virtual impedance & negative-sequence droop (recommended baseline)

- Controller measures I_2 (or V_2) and inserts a virtual $Z_{2,\ virt}$ so the inverter presents a finite, mostly inductive negative-sequence impedance using the compensating term discussed above.
- Benefits:
  - It provides a predictable (k-factor equivalence) response (i.e. $|I_2| \propto |V_2|$)
  - ~90° phasing by design, and fair sharing among multiple GFMs in proportion to their impedances (just like SG sub-transient reactances) can be achieved.

– It keeps the inverter a voltage source while limiting (VI-based CLM) and preserves ~90° I_2 phasing and predictable sharing
– The design can coordinate positive-sequence and negative-sequence limits and phase-current maximisation.

- Practical target: $Z_{2,\ virt} \approx Z_{1,\ virt}$ (symmetry of pos/neg sequence), and low R/X.

Sequence-controlled GFM (explicit positive-sequence/negative-sequence loops; hybrid)

- This design philosophy adds a decoupled negative-sequence regulator (e.g., 100-Hz rotating frame) to shape negative-sequence current I_2 (magnitude/phase) without compromising the voltage-source behaviour of the positive sequence.
- Several sequence control strategies exist, as shown in the Table 5.

This table groups common GFM negative-sequence approaches by their primary objective: shaping an effective Z_2, explicitly regulating I_2, explicitly regulating V_2, or suppressing I_2. The key message is that virtual-impedance style designs most naturally deliver predictable, near-quadrature I_2 and fair sharing, but only if the current limiter preserves "impedance fold-back" behaviour rather than hard clipping; approaches that target $I_2 \rightarrow 0$ reduce device stress but tend to degrade relay visibility and usually conflict with transmission-level FRT expectations.

- Use cases: fine-tuning toward strict 90° phasing, meeting a specific k-slope if passive Z_2 alone falls short, damping 2×-frequency oscillations in VSM/droop loops.
- Caution: keep this loop subordinate to the primary voltage/frequency control so the unit remains a voltage source.

Table 5 Grid-forming inverter negative-sequence control options, control objective, expected fault behaviour, and current-limiting caveats

Method family	Primary objective	Typical behaviour under fault/unbalance	Key caution (one line)	Ref.
Plain voltage-source GFM, no explicit unbalance path	Hold voltage, no special V_2/I_2shaping	I_2 is whatever results from internal dynamics and network coupling, until limited, not intentionally shaped	Can be mis-phased near limits, hard to make protection-friendly without added design	[11] [12]
NSVI: virtual impedance shaping (incl. droop style)	Make negative-sequence behaviour look like a Thevenin source behind a designed Z_2 (often mostly inductive)	Approximately impedance law: $I_2 \approx \frac{V_2}{Z_2}$, so if $X_2 \gg R_2$, I_2 is near quadrature with V_2	If R_2/X_2 is too high, angle drifts toward in-phase, limiter should prefer impedance foldback over hard clipping	[13] [14]
NSCI: explicit I_2injection	Hit (k)-slope and angle directly	A simple and common form is complex gain: $I_2^{\star} = k_2\, V_2$, where $k_2 = \mid k_2 \mid e^{j\phi_2}$; $\mid k_2 \mid$sets the slope and $\phi_2$sets the phase of $I_2^{\star}$ relative to V_2.	Sensitive to k_2 and limiter priority, V_2 estimation delays/noise propagate directly into $I_2^{\star}$.	[14] [15]
NSVC: explicit V_2 shaping	Improve terminal voltage symmetry, shape effective Z_2seen at the terminals	Drives V_2 toward a target, typically $V_2 \rightarrow V_2^{\star}$ (often $V_2^{\star} = 0$, but not necessarily), with the implied I_2 then set by the network	If $V_2^{\star}$ is too aggressive, it can under-deliver the required I_2during LVRT, especially when current-limited	[14] [16]
Balanced-current objective (BTPC, $I_2 \rightarrow 0$)	Keep phase currents balanced, minimise device stress	Enforces $I_2^{\star} \approx 0$ (or strongly penalises I_2), which reduces negative-sequence relay visibility	Generally conflicts with LVRT expectations unless strictly limited to minor steady-state unbalance, with overrides during faults	[15] [11]

Current-limit handling variants

- There are two mainstream CLMs used in the industry. They are:
  - Current Saturation (CS) based limiters: They are instantaneous, magnitude, and priority schemes that work for both GFL and GFM but effectively make the unit behave like a current source during FRT and can under-utilise capacity or distort sequence priorities. It should be used with care for IEEE 2800 coordination [13].
  - Virtual Impedance (VI) based) limiters: They are preferred for GFM so the inverter remains a voltage source while limiting the current. The design of Z (or effective impedance) should be mostly inductive and coordinated with positive / negative sequence limits [13] [17].
- Balanced reduction: It proportionally reduces positive/negative-sequence voltage commands so all sequence currents back off together to ~95–100% of I_{max}.
- Phase-current maximisation (G1/G2 scaling): Under asymmetrical faults, this approach adapts the I_1/I_2 split so at least one phase approaches $\sim I_{max}$ (no headroom left on any phase), rather than holding a fixed I_1: I_2 ratio. Normally implemented as vector-limiting followed by a per-phase check/scale so negative-sequence support is maximised without mis-phasing [14].
- Selective prioritisation (policy-driven):
  - Positive-sequence priority to support bulk voltage (allow a bit more V_2 temporarily), or
  - Negative-sequence priority to ensure relays see sufficient I_2 (accept deeper pos-seq voltage dip) [16].
- Common goal: Avoid abrupt clipping, maintain voltage-source character behind a higher effective impedance, then restore once the event subsides.

Restricted mode (fault-limited GFM behaviour)

- Definition: When any phase current approaches the limit (e.g., $|i\phi| \geq I_{max} - \varepsilon$) for a brief dwell (≈½–1 cycle), the GFM enters a restricted mode that keeps voltage-source behaviour while enforcing current limits. Instead of hard clipping the current vector, the controller folds back the internal EMF (E*) and/or raises the effective virtual impedance (preferably inductive) so that the phase currents respect Imax and the negative-sequence phasing (~+90° lead of V_2) is preserved [16].
- Typical control actions:
  - Folding back virtual impedance / internal EMT (E*): This action increases $X_{2,virt}$ (low R/X) and/or reduce E* to back off both I_1 and I_2 coherently (no abrupt clipping).
  - Sequence coordination: This action applies the phase-current maximisation step to saturate available headroom, then scale (I_1, I_2) together to maintain angle; avoid re-shaping I_2 after the limiter has acted.
  - Anti-windup & ripple management: This action enables anti-windup in V/Power loops; manage double frequency DC-link ripple (notch/PR or bandwidth shaping) to prevent oscillatory re-entry.
- Entry/exit criteria
  - Enter: any phase current approaches the limit ($|i\phi| \geq I_{max} - \varepsilon$) for 0.5–1 cycle.

– Exit: all phase current magnitudes |iϕ| ≤ 0.9·I_{max} for 2–4 cycles and DC-link ripple back within threshold; then restore nominal E*/$Z_{2,virt}$ smoothly.

- Design intent: The goal is not to become a current source but to remain a voltage source behind a larger (mostly inductive) effective impedance while limited, so negative-sequence angle and sharing stay predictable, and the unit cleanly re-enters full GFM once the fault clears.
- Optional note (place under "Virtual impedance & negative-sequence droop – Benefits"): In restricted mode, VI-based limiting lets the GFM remain a voltage source (by E*/$Z_{2,virt}$ fold-back), preserving ~90° I_2 phasing and predictable sharing until currents fall below Imax.

Bottom line: This approach is the most robust GFMs that emulate SGs, i.e. low and mostly-inductive $Z_{2,}$ I_2 ~90°, a predictable sharing, and graceful behaviour at limits. Designs that try to eliminate I_2 (by forcing zero V_2 internally) reduce device stress but do not support the system's modern standards [11] [16].

2.4.3 Negative-sequence current and phase relation

Since a GFM's negative-sequence behaviour is governed by impedance, it will naturally yield a current that is ~90° out of phase with the negative-sequence voltage (if the impedance is mostly inductive). For a synchronous generator, we noted I_2 leads V_2 by ~90°. A well-tuned GFM with predominantly inductive virtual impedance will behave similarly. From the grid's perspective, this is equivalent to a *capacitive* response: the GFM's negative-sequence current leads the terminal negative-sequence voltage by ~90°, mirroring a synchronous generator.

VDE FNN frames negative-sequence behaviour for GFM units in terms of an effective Thevenin impedance and recommends that the effective negative-sequence (counter-system) impedance is aligned with the positive-sequence (co-system) impedance during normal operation, with a small resistive component for damping. The intended outcome is a predominantly reactive I_2 response (near-quadrature with terminal V_2) and predictable sharing of unbalanced currents.

To express the GFM's negative-sequence current analytically, consider the internal voltage source and the grid forming a negative-sequence circuit. If the internal negative-sequence voltage is zero (ideal balanced internal reference) and the terminal has $V_2\angle\theta$, the current will be:

$$I_2 = \frac{0 - V_2\angle\theta}{Z_2}$$

$$I_2 = \frac{V_2}{|Z_2|}\angle(\theta - \pi - \emptyset z)$$

$$I_2 = \frac{V_2}{|Z_2|}\angle(\theta - 270^{\circ}), \quad \emptyset z = 90^{\circ}$$

With a purely inductive Z_2 ($\emptyset z$ = +90°), the negative-sequence current leads the negative-sequence voltage by 90°. Thus, the phase relationship in GFM is inherently set by the impedance angle. Designing Z_2 to be highly reactive ensures the GFM meets the intent of standards (pure negative-sequence VAR support).

One key difference from GFL is how the GFM achieves this 90° relation. It is not via an explicit current reference offset by 90°, but via the physics of its control loop. The GFM controls its positive-sequence voltage (through, e.g., droop) and often does not explicitly control negative-sequence voltage; negative–sequence current flows according to the impedance. As long as the inverter's bandwidth is high enough, the instantaneous negative-sequence current will follow Ohm's law at the connection point.

The k-factor requirement (reactive negative-sequence current per unit of negative-sequence voltage) can be satisfied by a grid-forming inverter simply by choosing its virtual negative-sequence impedance to be mostly inductive. In that case, the current follows Ohm's law at the terminals and remains close to quadrature without explicit sequence-current commands. Equivalently, k-factor is just the effective negative-sequence susceptance seen by the grid. Thus, for a target range k = 2 to 6 (e.g. German code), choose the virtual reactance X_2,virt ≈ 0.5 to 0.167 pu. This mapping is valid provided resistance is small (low R/X), current limiting is inactive, and the control bandwidth meets the specified response time.

Ohm's law in inductive form (negative sequence):

$$I_2 \approx j \frac{V_2}{X_{2,virt}}$$

Magnitude mapping to k-factor/susceptance:

$$\left|\frac{I_2}{V_2}\right| \approx \frac{1}{|X_{2,virt}|}$$

Compact statement:

$$k \approx \left|\frac{I_2}{V_2}\right| \approx \frac{1}{|X_{2,virt}|}$$

Caveats and practical notes

- Phasing: Keep R/X small; otherwise, the response is not purely reactive, and the k ≈ 1/X mapping degrades.
- Limits: Once I_{max} or voltage ceilings apply, the effective k is clipped.
- Dynamics: Meet the code's response window; filters in the 100-Hz (dq_2) path must not be overly sluggish.
- GFM tuning note: For GFM, achieving the same ≤4-cycle settling generally requires more exhaustive tuning of the +/− sequence current controllers and a suitable negative-sequence control/limit strategy.

2.4.4 Current limitations and prioritisation

Perhaps the greatest challenge for GFMs under unbalance is handling current limits while preserving stable voltage-source behaviour. Because a GFM attempts to regulate voltage, if a severe fault causes huge current demand, the inverter must enter a current-limiting mode to protect itself. A naïve approach (clipping the voltage) can cause the inverter to lose synchronisation or oscillate, since abruptly transitioning from voltage control to current saturation can introduce phase errors.

The VDE FNN (2025) note provides guidance on this. It stipulates that *"the voltage-source behaviour is a permanent and fundamental property that must be maintained even when the unit reaches a current limit,"* albeit allowing some distortion for very short periods. To meet this expectation, three design principles apply as shown in Table 6:

Table 6 Design principles to maintain voltage source behaviour

Design principle	Design details
Approach to limit	As the current reaches the maximum current, increase the effective negative-sequence impedance $Z_{2,eff}$ (and if needed, positive-sequence impedance $Z_{1,eff}$) and/or reduce the internal set-point of EMF (E*) to hold the magnitude of the current close to 0.95 to 1 pu without hard clipping. Promptly restore nominal impedance and set-point EMF (E*) after the event.
Transient allowance	Brief clipping or distortion (≈20–40 ms) may be tolerated during severe disturbances, but not as a sustained mode.
Recovery	After the event clears (voltage recovers), promptly remove the limiting and re-establish normal voltage control.

In effect, the GFM should fold back its voltage setpoint or increase its virtual impedance such that current is curtailed just enough to stay within I_{max}, rather than hitting a hard limit and producing a distorted waveform. After the event clears, the GFM must resume voltage-source behaviour as soon as feasible to re-establish stable regulation.

Implementing this can be done via a current-limited voltage control algorithm. For example, some GFM controls monitor the instantaneous current, and if it exceeds a threshold, they dynamically adjust the voltage reference magnitude and phase to reduce the current. Others essentially switch to a transient current control mode but with a managed return to voltage mode (sometimes called *"voltage priority with current limit"*). The key is to do this without introducing large phase discontinuities. Some research (EPRI, etc.) suggests using a proportional sharing of sequences under a limit similar to GFL. In practice, a GFM under limit will attempt to reduce both positive- and negative-sequence voltage outputs proportionally, so that it continues to supply some of each rather than dropping, for example, the negative-sequence entirely. This concept mirrors the earlier discussion on backing off both I_1 and I_2. In a GFM, this might manifest as backing off both the positive-sequence voltage magnitude and any internal negative-sequence voltage (if utilised) or effectively raising the output impedance equally for all sequence components.

2.4.5 System stability implications

From a stability perspective, GFM inverters generally have an advantage in grid stability for balanced conditions if the current limitation is not reached, but unbalanced operation is a special case. The presence of unbalanced currents causes oscillatory forces inside the inverter control (e.g. second-harmonic components in the instantaneous power and AC currents). A well-designed GFM is expected to tolerate these without losing synchronism.

Unlike GFL units, GFMs are not prone to PLL instabilities under negative-sequence conditions. Nevertheless, they must withstand the double-frequency ripple in their DC link and control currents. Virtual impedance and fast inner-loop regulation help damp the effect of negative-sequence currents on the DC bus or control angles. Adding a small resistive component to the virtual impedance (R/X ≈ 0.1) further improves damping, while maintaining predominantly reactive behaviour. Consistency in negative-sequence impedance across multiple GFMs is also important as mismatched Z_2 values can lead to circulating negative-sequence currents between units.

If the GFM uses a droop-based control, the negative-sequence current does not directly affect the power measurements used for droop (since those typically use average active/reactive power, which filters out double-frequency components). However, certain GFM strategies, like Virtual Synchronous Machine (VSM) control, will feel oscillations due to imbalance, analogous to a real machine. Careful tuning or supplemental damping (e.g. notch filters at 2× frequency in the power control loop) might be employed to ensure these oscillations do not amplify.

Research by PNNL has indicated that traditional GFMs (with no special unbalance control) can exhibit a very large impedance to negative-sequence (meaning they contribute little I_2) and potentially a problematic phase angle (e.g., nearly 180°), which is unsuitable for protection. The solution is precisely what we've described, i.e. adding a negative-sequence control scheme to make them "inject negative-sequence current through control" and emulate an SG's response. In doing so, GFMs become much more friendly to the grid during faults.

2.4.6 Steady-state considerations

In steady-state small unbalances (e.g. a slight voltage unbalance in the grid), a GFM will inherently attempt to correct it by driving negative-sequence current. This could result in a continuous small I_2 flow, which is an additional heating/stress factor on the inverter. The FNN guidance allows GFMs not to overreact to minor imbalances: specifically, it mentions not specifying a minimum negative-sequence impedance (so it could be high if needed), and allowing minor internal negative-sequence voltage to limit currents greater than 3% of the rated value to be continuously sustained. In practice, a GFM might have a threshold. If the imbalance is below a few per cent, it might not fully compensate (or it might intentionally leave a slight negative-seq at its terminal to avoid looping large currents). This is analogous to how synchronous generators have negative-sequence current limits; they will produce some current for minor unbalances, but can't go beyond a certain continuous level.

2.4.7 Practical design targets

Table 7 provides practical design targets for GFM inverter.

Table 7 Practical design targets for GFM inverter

Attribute	Practical design target
Phase relationship	$\angle(I_2) \approx \angle(V_2)$ + 90° (reactive injection, tight tolerance).
Slope (k – equivalent)	Suitable negative-sequence effective impedance ($Z_{2,eff}$) for $k \approx 2 - 6$ which results in $Z_{2,eff} \approx 0.5 - 0.167$ pu.
Symmetry	Maintain negative-sequence effective impedance close to positive-sequence effective impedance (i.e. $Z_{2,eff} = Z_{1,eff}$) during normal operation.
R/X	Negative-sequence loop operates at 2× frequency ~0.1 to keep I_2 predominantly reactive while adding light damping.
Limits	Regulate near 95 – 100% of I_{max}. Avoid sustained clipping and reduce all sequences proportionally unless policy dictates otherwise
Sharing/priority	Ensure that parallel GFMs present compatible negative-sequence impedance (Z_2) to prevent circulating unbalanced currents.
Steady-state behaviour / deadband	Apply deadbands/thresholds so that minor unbalances (<~3% V_2) do not trigger continuous I_2 injection

Finally, it is important to note that GFMs do not inherently "inject more" negative-sequence current than GFLs. Their I_2 contribution depends strongly on the chosen $Z_{2,eff}$. If $Z_{2,eff}$ is tuned high, a GFM may contribute very little I_2; if tuned low, it may supply substantial I_2 comparable to or greater than a synchronous generator. Thus, careful tuning of $Z_{2,eff}$ is essential to achieve both compliance and useful system support.

2.4.8 Summary

A well-designed GFM inverter in unbalanced conditions behaves as a synchronous-machine-like voltage source behind an impedance. Its negative-sequence current arises passively from a mostly inductive, finite Z_2, giving ~90° reactive support proportional to $|V_2|$ (k-factor equivalence). By matching Z_2 to the positive-sequence impedance, the GFM ensures fair current sharing among units and supports grid code requirements for reactive and protection-friendly phasing.

Robust implementations use virtual impedance or negative-sequence droop as a baseline, with optional lightweight sequence controllers to fine-tune magnitude/phase and damp double-frequency oscillations, all without undermining voltage-source behaviour. At current limits, GFMs should fold back smoothly, raising effective impedance or reducing internal voltage, to regulate near 95–100% maximum current, then restore full voltage control as conditions normalise.

Table 8 Summary of similarities and differences between GFL and GFM during unbalanced voltage conditions

Aspect	GFL	GFM
Control nature	Current source synchronised via PLL. Tracks current references in d–q frames.	Voltage source behind impedance Sets terminal voltage directly.
Negative-sequence control	Requires explicit decoupled negative-sequence control (dual-SRF), without this $I_2 \approx 0$ or mis-phased.	Negative-sequence current arises through impedance Negative-sequence current shaped via chosen $Z_{2,eff}$ (virtual impedance/droop), preferably low-R/high-X.
Phase relation (I_2 vs V_2)	Explicitly set by control (≈ +90° lead on V_2 ±10° window in codes such as IEEE 2800). Poor tuning can misalign or add resistive error.	Emerges from impedance; ≈ +90° lead if $Z_{2,eff}$ is predominantly inductive (low R/X). If $Z_{2,eff}$ is too high or too resistive, I_2 reduces or deviates.
Magnitude of I_2	Limited by the vector current ceiling I_{max}. Headroom depends on active/reactive priority and positive-sequence demands.	Capped by I_{max}. I_2magnitude depends strongly on $Z_{2,eff}$. Low $Z_{2,eff}$ → large I_2 (until limited); high $Z_{2,eff}$ → small/negligible. Same Imax governs both.
Current limits	Enforced by vector limit with proportional scaling of I_1 and I_2 to stay within I_{max}. Policy may prioritise reactive over active.	Managed by raising $Z_{2,eff}$ and/or reducing internal voltage setpoint so current remains near I_{max}. The intent is to preserve voltage-source behaviour.
Timing target	Straightforward to tune for ≤2.5-cycle rise / ≤4-cycle settle with dual-SRF (mind ~1-cycle extraction delay).	Needs exhaustive tuning and an appropriate negative–sequence control/CLM to meet ≤4-cycle settle (sensitive near current limits).
Steady-state behaviour	Deadbands of typically <2–3% V_2 to avoid response to minor unbalances, reducing stress from continuous double frequency ripple.	May inject small I_2 even for minor unbalances Many designs apply thresholds or an internal V_2 to limit continuous stress.
Analogy to synchronous generator	Mimics SG negative-sequence reactance using k-factor (k ≈ 2–6 → $X_{2,eff}$≈ 1/k ≈ 0.5–0.17 pu), valid for low R/X and outside current-limit.	Behaves like an SG behind reactance; I_2 support depends on $Z_{2,eff}$ tuning, not an inherent superiority.
System/protection implications	If I_2 is small (priority choice or poor tuning), residual V_2 may remain high, affecting protection sensitivity.	With inductive $Z_{2,eff}$, I_2 is predictable (+90° lead) and supports directional/sequence elements, however if $Z_{2,eff}$ is very high, I_2 may be below expected support.

2.5 “Absorption” vs “Injection” of negative-sequence current

2.5.1 Definitions and phasor convention (device-level)

In this document, ‘’injection’’ and ‘’absorption’’ refer to reactive-power flow in the negative-sequence network at the device terminals.

- Injection: negative-sequence current leads the device’s terminal V_2 by ~90° (capacitive from the grid’s perspective) → VARs flow from the device to the grid, tending to reduce residual V_2.
- Absorption: negative-sequence current lags the device’s terminal V_2 by ~90° (inductive/resistive) → VARs flow from the grid to the device, generally not reducing V_2 and potentially aggravating unbalance.

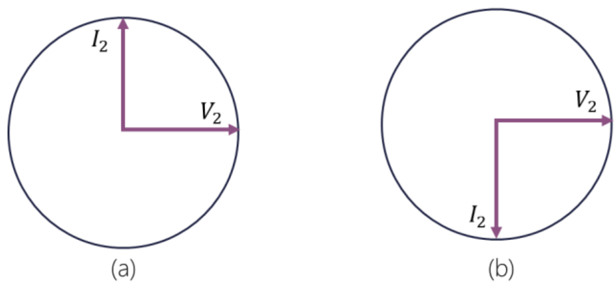

Figure 5 (a) Capacity and (b) Inductive: from grid perspective

2.5.2 Avoiding a common confusion (relay vs device reference)

Directional/sequence relays often define current into the protected element and use a local polarising sequence voltage. Under that relay convention, the same physical behaviour can be described with opposite lead/lag language. Throughout this report, we use the device → grid current convention and judge injection/absorption against the device terminal V_2.

2.5.3 Typical behaviour by technology

Table 9 provides a high-level summary of various technologies and its relationship with negative-sequence currents.

Table 9 Various technologies and its behaviour for negative-sequence current

Technology	Negative-sequence current behaviour
Synchronous Generators	Predominantly inductive negative-sequence reactance i.e. injects negative-sequence VARs (device I_2 ≈ +90° lead of terminal V_2). Magnitude limited by thermal/torque constraints.
Type-III (DFIG) wind turbines	Tend to absorb by default (stator tied to grid). Rotor-side control can mitigate but may not reliably deliver leading I_2 under severe faults.
GFL full converters	Behaviour set by control. Modern grid codes expect predominantly reactive negative-sequence current with I_2 ≈ +90° lead (±10°) of terminal V_2, with a defined slope (k-factor) and within current limits.
GFM full converters	Behaviour set by tuned negative-sequence impedance $Z_{2,eff}$ (and its R/X). With low-R/high-X (predominantly inductive) $Z_{2,eff}$ they provide injection (near-quadrature, ≈ +90° lead), subject to current limits

2.5.4 When is injection preferred vs absorption?

- Injection (leading I_2): preferred for transmission-level support; reduces residual V_2, improves phase-voltage balance during unbalanced faults, and yields predictable phasors for protection. Hence, codes for full-converter IBRs generally specify predominantly reactive I_2 with ≈ +90° lead with ±10° tolerance.
- Absorption (lagging I_2): acceptable where physics or device protection dominate (e.g., some distribution-level compensators to shield sensitive loads), but not the primary system strategy for rebalancing in IBR-rich grids.

2.5.5 Bottom line

- Use leading negative-sequence current (injection) for full-converter IBRs to provide effective voltage rebalance with limited current headroom and to maintain relay dependability.
- Recognise that rotating machines appear as injection under this convention; manage their contribution via established thermal/torque limits, while system-level rebalancing is delivered by appropriately tuned and tasked converters.

2.6 Standards and research guidance on negative-sequence behaviour

This section summarises various standards and research approaches for negative-sequence behaviour of a device and expected response that supports overall system performance.

This section distinguishes between (i) mandatory performance statements within the cited standards or grid codes, and (ii) common industry implementation practices used to achieve compliance. Where numeric thresholds or slopes are shown, they are treated as examples or project-specific settings unless explicitly stated as normative requirements.

2.6.1 IEEE 2800-2022

IEEE Std 2800-2022 is a performance standard for IBRs in the bulk power system. While IEEE 2800 is not written as a grid-forming specific standard, its negative-sequence and current-limit coordination expectations are commonly used as a reference point, and GFM-specific interpretations are typically handled via supplementary guidance and project-specific requirements. It explicitly addresses negative-sequence current injection for the first time in an IEEE standard. Key points include:

- Negative-sequence injection requirement: In abnormal voltage conditions, IBR plants *"shall inject negative-*sequence *current dependent on the IBR terminal negative-sequence voltage"*, in addition to positive-sequence support. The standard does not specify the exact magnitude (which is left to grid codes or manufacturers within broad limits), but it requires the behaviour to be qualitatively specified.
- Phase angle of I_2: For full converter IBRs (like PV, battery, Type-IV wind), IEEE 2800 mandates that the *negative-sequence reactive current lead the negative-sequence voltage by 90–100°*. Essentially, the inverter's I_2 must be close to pure reactive (capacitive). For Type-III wind (DFIG), a looser tolerance of 90–150° lead is allowed, acknowledging the limitations of partially converter-fed machines. The narrow 90–100° range for full converters is a stringent

requirement; it means only up to ~15% of I_2 can be resistive (since cos(90°)=0 and cos(100°)=0.17), ensuring the inverter primarily provides VARs in negative-sequence.

- Negative-sequence magnitude trigger and ceiling (example interpretation consistent with IEEE 2800 guidance): For severe negative-sequence deviations, an IEEE 2800-compliant control interpretation commonly used in industry is that when terminal V_2 is ≥ 0.25 , the plant can inject negative-sequence reactive current up to its maximum current rating, subject to the overall current limit coordination with positive-sequence requirements.
- Positive- vs negative-sequence priority: IEEE 2800 requires IBRs to have the capability to control both I_1 and I_2 outputs and to respect overall limits. However, it leaves room for different control philosophies. It stipulates that during faults, if priority is given to active current (e.g., an energy storage system maintaining output), the IBR must still meet minimum reactive injection requirements up to the limit. Many interpret 2800 as effectively requiring reactive current priority for most applications, since dynamic voltage support is crucial. In practice, manufacturers comply by using the proportional curtailment approach, which inherently meets the intent because if I_{max} is reached, both sequences reduce together, meaning you can't have a case where you keep full $I_1$and drop I_2 to zero (or vice versa) unless one of them was zero to begin with. In IEEE 2800-style descriptions, this is often expressed in terms of incremental reactive components ΔI_{q1} and ΔI_{q2}; when the total current limit is reached, an equal-magnitude reduction of ΔI_{q1} and ΔI_{q2} is generally preferred, while avoiding cases where $\Delta I_{q1}$is reduced below ΔI_{q2}.
- Performance verification: The standard includes test specifications (ride-through tests) where an IBR is subjected to, e.g. an unbalanced fault (like single-line-to-ground) and must respond with the appropriate current injection within a specified time. It lists response times (e.g. <2.5 cycles to reach 90% of required I_2) and steady-state tolerances (±2.5% to +10% of I_{max} for the settled current). This ensures practical implementations actively control I_2 rather than passively letting it flow or suppressing it.
- In summary, IEEE 2800 provides the high-level mandate: inject negative-sequence reactive current for voltage unbalances, ~90° phase-shifted, and manage your total current without exceeding limits. It does not prescribe the control architecture; however, in practice GFL implementations commonly use decoupled ± sequence control (often realised via a dual synchronous reference frame / dual-dq structure or equivalent sequence-separation methods), while GFM implementations commonly meet the intent via matched positive/negative-sequence virtual impedance concepts.

2.6.2 German Grid Code (VDE-AR-N 4120/4130)

Germany's grid codes (VDE-AR-N 4120 for high voltage, 4130 for transmission) have been pioneers in specifying *quantitative requirements* for asymmetrical fault current. The concept of k-factor originates from these codes. Key aspects include:

- k-Factor definition: In these rules, *k* is essentially the slope of reactive current injection versus voltage dip. A typical value is k = 2, meaning a 5% voltage dip triggers a 10% reactive current injection (both for positive-seq dips and negative-seq unbalances). The code often allows k to be in a range (2–10 for some distributions, 2–6 for transmission) – the German TCR (technical connection rules) specifically indicate k between 2 and 6 for negative-sequence. Higher k means a stronger response (stiffer behaviour).

- Positive- and negative-sequence requirements: Initially, older codes focused on positive-sequence (balanced faults), e.g. providing a reactive current at least proportional to the drop with k. However, the German code update recognised that only injecting balanced currents during an unbalanced fault could cause the healthy phases to overvoltage. Thus, VDE-AR-N 4120 requires a negative-sequence reactive current injection similarly proportional to V_2. *"The increment of reactive current in the positive- and negative- sequences should be proportional to the depth of the voltage dip."* This language, as cited earlier, essentially enforces the same k on V_2. An excerpt: *"In Germany, VDE-AR-N 4120 requires additional reactive negative-sequence current proportional to the negative-sequence system voltage at PCC."*.
- Limitation to prevent overvoltage: The German code also explicitly mentions avoiding raising non-faulted phase voltage too much. It achieves this by proportional sharing – if you inject the proper I_2, the positive-sequence injection will not cause as severe a voltage rise on the healthy phases. Additionally, some German specifications included a factor to slightly reduce I_1 injection if needed to protect unfaulted phases (sometimes referred to as the "unbalanced current control" factor). The k-factor method inherently addresses that because I_1 and I_2 are tied to their respective voltage deviations. For example, in a solid single-phase fault, one phase voltage drops (creating a large V_2), while the positive-sequence voltage also sags. The inverter injects a large i_{q1} for the overall sag and simultaneously an I_2 for the imbalance. The healthy phase sees i_{q1} raising it, but also sees I_2 pulling it down (since I_2 flows into the faulted phase from the others, effectively). The net effect is a balanced support.
- In practical terms, manufacturers selling in Germany program their GFL inverters with that dual-sequence current controller using k (often k=2 or 3 by default). For GFMs, Germany is starting to allow them at the transmission level under special project provisions; they, too, must satisfy these fault current rules not to disrupt protection.

2.6.3 VDE FNN Guidance (May 2025 Note on GFM Units)

The VDE FNN note "Network-forming properties of generating units" (Version 2.0, 2025) [4] [3] gives detailed recommendations for GFMs, many of which we have already woven into the GFM discussion. To summarise the key guidance relevant to negative-sequence behaviour:

- Thevenin behaviour: A GFM unit should behave like a voltage source behind an impedance. It should not act like a current source except temporarily when absolutely necessary. This means maintaining a controlled voltage even under disturbances, which inherently means it will provide whatever current is dictated by the impedance (up to limits).
- Equal positive- and negative-sequence impedance: As noted, the "effective counter-system (negative-sequence) impedance should equal the co-system (positive-sequence) impedance in normal operation". This ensures symmetry; the inverter doesn't favour positive sequences at the expense of negative ones (until limits are reached). It also simplifies protection analysis, as the GFM will contribute to unbalanced faults in proportion to balanced faults.
- Minimal R/X (highly reactive): The note recommends that the control impedance have a low R/X ratio (around 0.1 or 10% damping). A small resistive component can help dampen oscillations, but too much would result in active negative-sequence current flows, which is undesired

(wasting capacity and potentially causing power oscillations). Thus, the negative-seq current from a GFM is intended to be primarily reactive (capacitive or inductive, depending on whether it's supporting or opposing the voltage).

- Current limit handling: The FNN note provides a nuanced approach to current limits. Before reaching the limit, it says *"the fundamental-frequency control impedance must be kept constant"*, in other words, do not alter the behaviour (so that the sharing of current remains proper). Once the current limit is *reached*, the GFM is allowed to clip, but should then *"regulate the current to 95%"* of the clipping level to avoid continuous distortion. Notably, it mentions *"current clipping is characterised by significant distortion"*, which is undesirable if it persists. After reaching a limit, if another event happens, the GFM should attempt to come out of the current limit quickly to respond as a voltage source to the new event. This implies that a GFM should *not latch* into current limiting for longer than necessary; it should restore normal voltage control as the system allows.
- Negative-sequence reactive current approximation: Under the Thevenin-behind-impedance approximation, and assuming the internal negative-sequence voltage is negligible, the negative-sequence current is set primarily by the effective negative-sequence impedance:

  $$I_2 \approx -\frac{V_2}{Z_{2,\mathrm{eff}}} \approx -\frac{V_2}{jX_{2,\mathrm{eff}}}$$

  With low R/X, I_2 is near-quadrature with V_2 (predominantly reactive), with negligible average negative-sequence real power, noting that instantaneous power still contains a 2ω component.
- Phase jump response: The FNN note also covers behaviour during sudden phase angle jumps (which cause an active power surge). While not directly about negative-sequence, it illustrates the design philosophy. Even when the GFM has to provide a burst of active current (for a frequency/angle disturbance), it should also meet a certain negative-sequence sharing if that angle jump caused unbalance. The note quantifies an "angular jump power" and requires at least 50% of the max possible to be delivered in the "marketed direction" (i.e. to counter the angle change) and at least 5% in the opposite direction for stability. This mainly ensures GFMs both source and sink some power during major events to stay synchronised. For negative-sequence, one could analogise that the inverter should respond to any sudden imbalance by immediately adjusting current according to its impedance, rather than, say, waiting or ignoring it.

Overall, the VDE FNN 2025 note is quite comprehensive. The takeaway for negative-sequence behaviour is that GFMs should act like well-behaved voltage sources in both sequences and handle limits gracefully. The guidance aligns with what IEEE 2800 expects (although IEEE 2800 was primarily written for GFL, its spirit also applies to GFM, and future revisions may explicitly cover GFM).

2.6.4 Research Insights (EPRI, NREL, PNNL, etc.)

Multiple research organisations have studied negative-sequence control in inverters to ensure stability and protection compatibility:

- EPRI (2019-2021) [5] : EPRI looked at the protection impacts of IBRs and how negative-sequence injection can help. They showed via simulation that without I_2 injection, a system with many IBRs had much smaller negative-sequence fault currents (e.g. 0.12 pu for a Type IV wind plant, vs

1.5 pu for an SG in the same fault). The phase angle of IBR I_2 was also abnormal (e.g. 131° or -101° instead of ~90°). This can confuse relays. By implementing a controller per IEEE 2800/VDE 4120 (i.e. injecting I_2 = kV_2 ∠90°), the IBR's effective negative-sequence impedance dropped, and the phase angle moved closer to 90°, improving consistency. EPRI recommended that all new inverter controls include this functionality to avoid protection blind spots. These angle windows are treated here as normative IEEE 2800 performance requirements for the device categories stated.

- PNNL (PSCC 2020, etc.) [7]]: PNNL researchers directly studied *negative-sequence impedance of IBRs* and its impact on relays. They demonstrated that a full converter under standard control can even appear *capacitive or resistive* in negative-sequence, meaning I_2 could lag or lead strangely, which is completely different from an SG. This explained why some relays misoperated in areas with high IBR penetration. Their proposed solution aligned with VDE-AR-N 4120: have the converter control impose a negative-sequence current proportional to V_2 (with gain k). Their results showed that doing so yields a much more SG-like response and restores the relay performance in most cases. They also pointed out that in doing so, the inverter uses any remaining capacity *after* positive-seq demands – confirming the concept of priority (positive-seq reactive given first priority, then negative-seq reactive). One interesting observation was that if a DFIG (Type-3 wind) uses its converter to actively cancel torque oscillations (i.e. suppress I_2), it will reduce its contribution to I_2 in the grid drastically. So there's a trade-off between mitigating mechanical stress in a DFIG vs supporting grid protection.
- NREL [6]: NREL has been deeply involved in writing IEEE 2800 and analysing gaps with IEEE 1547 (which governs distribution). In a 2023 gap analysis, they note IEEE 1547 (which covers <100 kV interconnections) currently lacks explicit negative-seq requirements, whereas IEEE 2800 has them. They emphasise the need for harmonisation so that even smaller inverters (e.g. rooftop PV, which can also cause unbalance issues on distribution feeders) inject negative-seq current appropriately. NREL also developed example control algorithms to comply with IEEE 2800, demonstrating a dual-sequence current controller that monitors V_1 and V_2 and outputs current references for each. Their test results show the inverter meeting the 90° phase requirement and not exceeding current limits by using the proportional back-off method. NREL's broader GFM research (as part of the DOE portfolios) also indicates that future GFMs must handle "unbalanced grid support" as a capability, on par with black start and inertia support.
- Other academic research: Many academic papers have tested different injection strategies. Some strategies include *balanced current injection* (only I_1) vs *unbalanced injection* (I_1 + I_2 per grid code) and even *over-injection* (where they try to maximise I_2 beyond the code for protection). They found that following the code (with I_2 injection) generally *improves relay faulted-phase identification and direction detection*. However, it might not solve every case – e.g. if fault current is very low, some relays still struggle. There is ongoing work on adapting relay algorithms (like making them less reliant on a 60° phase assumption between I_2 and I_1) to better handle IBR contributions. Nonetheless, from the system stability view, no negative-seq support at all is clearly worse: it can cause healthy-phase overvoltages, slower fault clearing, and even ferroresonance in extreme cases (if one phase goes overvoltage and drives saturation in transformers). Hence, the consensus of research is that controlled negative-sequence injection is essential in IBR-rich grids. An IEEE PES [18] report noted that some relays require on the order of 10% negative-sequence current relative to positive-sequence current to operate. If GFL IBRs

supply negative-sequence current proportional to negative-sequence voltage unbalance in line with *the k factor between 2 and* 6, it would help support intended protection operation.

2.7 Acceptance criteria and favourable behaviours during negative-sequence conditions

The effectiveness of an inverter's negative-sequence response should be judged against technical and protection-driven criteria. The following points describe what "good" looks like and how both GFL and GFM controls can achieve it, as well as typical pitfalls to watch for.

1) Adequate magnitude of negative-sequence current

Measure: deliver the grid code required negative-sequence current magnitude without violating current limits.

- GFL: Modern sequence-decoupled GFLs can meet prescribed slopes provided current headroom and priorities permit; legacy under-delivery was implementation-specific, not fundamental.
- GFM: With a designed, predominantly inductive $Z_{2,\mathrm{eff}}$, GFMs can reproduce synchronous-machine-like negative-sequence impedance behaviour (near-quadrature phasing and a chosen $|I_2|/|V_2|$ characteristic) up to the converter's overcurrent limit $I_{\max}$. This does not imply a comparable absolute fault current magnitude to an SG, which is typically higher due to greater short-time overcurrent capability. Higher R/X and current-limiting behaviour can further reduce the realised $|I_2|/|V_2|$ and distort phasing.

2) Correct phase (~90° reactive)

Measure: Negative-sequence current should be predominantly reactive to provide reactive power support and align with protection expectations:

$$\angle I_2 \approx \angle V_2 + 90^\circ\ (\pm 10^\circ)$$

- GFL: Explicitly enforce ~90° lead via decoupled controllers; needs careful cross-coupling compensation and filter tuning.
- GFM: Tends to provide ~90° lead by virtue of inductive virtual impedance; significant R/X introduces active components and may appear "absorbing."

3) Fast response and sustained support

Measure: ≈1 – 2 cycles for initial response and sustainment and stable through the disturbance (e.g., IEEE 2800's time windows).

- GFL: Meets target with adequate bandwidth; weak-grid PLL settings and negative-sequence filters are common bottlenecks.
- GFM: Responds immediately as a voltage source; near limits, impedance stepping should be slew-limited to avoid phasing errors.

4) Voltage unbalance mitigation

Objective: reduce Voltage Unbalance Factor (VUF) and avoid over/under-voltage on unfaulted/faulted phases:

$VUF = \frac{V_2}{V_1}$ (sequence-domain measure of asymmetry at the point of connection).

Indicative success checks (phase-domain, complementary to VUF): keep the faulted-phase voltage above ~0.5 pu and healthy-phase voltages below ~1.1 pu (indicative).
Note: VUF is defined in the symmetrical-component domain, while phase-voltage limits are assessed in a, b, c. Both should be evaluated because a lower VUF does not automatically guarantee phase voltages remain within equipment limits, and vice versa.

- GFL: Can reduce VUF via targeted I_2, but as a current source, it cannot guarantee the terminal voltage in high source impedance. It cannot guarantee terminal phase voltages under high source impedance.
- GFM: More decisive phase-voltage support; too-low $Z_{2,virt}$ can push healthy-phase overvoltage, tune sensibly. As, overly low $Z_{2,\mathrm{virt}}$(or aggressive unbalanced control) can push healthy-phase overvoltage, the tuning must balance VUF reduction against phase-voltage limits.

5) Coordination with protection (50Q / 51Q / 67Q)

Relays need sufficient $|I_2|$ and clear reactive phasing for reliable pickup/directionality.

- GFL: Controller provides predictable phasing; limited magnitudes (due to priorities/limits) may challenge pickup.
- GFM: Typically strong relay visibility; mis-tuned R/X or hard clamps can transiently distort angles.

6) Dynamic and control stability of inverter

- GFL: Vulnerable to PLL/2× frequency cross-coupling if filters and bandwidths are mis-set; well-tuned designs are stable.
- GFM: Avoids PLL issues but must manage current-limit transitions by increasing effective impedance rather than clipping to prevent hunting.

7) Inverter self-protection and survivability

- GFL: Scales sequence currents under I_{max} with an explicit priority scheme (often positive sequence first).
- GFM: Smoothly reduces positive- and negative-sequence voltage commands to stay below I_{max}; needs DC-link ripple management at 2× line frequency.

8) Steady-state unbalance and thermal tolerance

- GFL: Uses deadbands/thresholds so minor persistent unbalance does not drive continuous negative-sequence current and associated heating; accepts a small residual VUF.
- GFM: May source I_2even for small unbalance, improving voltage quality but increasing thermal duty; apply thresholds and continuous I_2limits (or an intentional internal V_2) to manage long-duration stress.

9) Coordination with legacy equipment

- GFL: Current-source behaviour can be unfamiliar to legacy schemes, but can be made compatible with consistent I_2 magnitude and reactive phasing (supporting phase selection and 50Q/51Q/67Q elements).

- GFM: Closer to synchronous-machine behaviour; generally integrates well with motors, synchronous condensers, and legacy relays when $Z_{2,\mathrm{virt}}$ is sensibly selected (low R/X, predictable limiting).

10) Verification and measurement conventions

Verify negative-sequence performance using the same sequence/phasor measurement method used for compliance testing (for example, a one-cycle moving DFT), and report both sequence phasors and reconstructed phase currents. State the sign convention and phasor reference (for example, device → grid current, and "lead/lag" defined relative to the terminal V_2). Confirm behaviour under plant-level controls and current limiting, since limiter nonlinearities and measurement delays can materially alter I_2 magnitude and angle, and may shift which phase reaches the instantaneous current ceiling.

3 Simulation studies investigating the impact of unbalanced voltages on GFM and GFL IBR

Earlier chapters establish, largely in theory, how grid-following (GFL) and grid-forming (GFM) inverter-based resources (IBR) differ from synchronous generators when the grid voltage becomes unbalanced (i.e. develops a negative-sequence component, as happens during asymmetric faults such as line-to-ground and double-line-to-ground events). This section puts that theory to the test through simulation. The driving concern is protection compatibility: legacy protection schemes (negative-sequence overcurrent 50Q/51Q, directional 67Q elements, faulted-phase selectors) were designed around the synchronous generator's behaviour. This behaviour is a large, predictable negative-sequence current that leads the negative-sequence voltage by roughly 90°. As IBR displace synchronous machines, it is no longer safe to assume the network will deliver this response. These studies quantify what GFL and GFM IBR actually do under unbalance, and benchmark them against a synchronous generator as the reference "good" behaviour.

The simulations characterise each technology's negative-sequence response across a range of devices, operating points (e.g. −0.9, 0.5, +0.9 pu), grid strengths (weak SCR = 3, X/R = 1 vs. strong SCR = 10, X/R = 10) and fault types. The technologies span a synchronous machine (benchmark), generic and site-specific GFL BESS, Type 3 and Type 4 wind farms, generic and site-specific GFM BESS, and GFM solar (droop and VSM). Most of these technologies assessed for both with and without negative-sequence (NS) control enabled. The assessment focuses on several protection-relevant attributes:

- Phasor relationship between negative-sequence current and voltage (is it ~90° reactive/leading, like a synchronous generator?)
- Injection vs. absorption of negative-sequence current (injection is preferable for protection dependability)
- Effective negative- and positive-sequence impedance
- Voltage unbalance factor
- Speed and stability of the response during the fault

A recurring high-level finding is that most IBR do not naturally reproduce the synchronous generator's response, but enabling NS control (notably on the site-specific GFL BESS, Type 4 WF, and site-specific GFM BESS) moves them closer to the desired ~90° leading, injecting behaviour.

3.1 SMIB Studies

3.1.1 Study setup

Figure 6 shows the study set-up for a SMIB assessment. The generation technologies, system conditions and scenarios studied during this work are listed in Table 10.

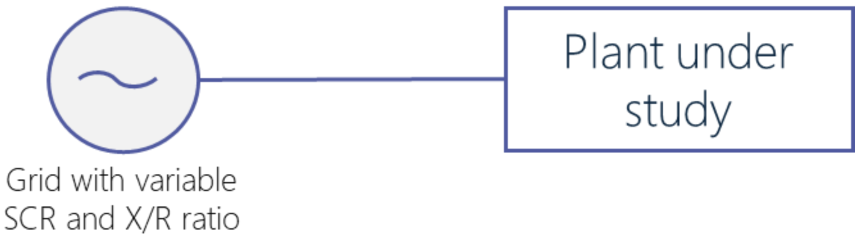

Figure 6 SMIB setup

Table 10 List of technologies, operating points, SCR values, X/R ratios and types of fault considered during the work

Sr No	Technology	Initial Operating point	SCR and X/R ratio	Type of fault
1	Synchronous machine	0.5 pu	SCR = 3 and X/R = 1	L-G fault
2	Generic GFL BESS without NS control	-0.9 pu, 0.5 pu and +0.9 pu	SCR = 10 and X/R = 10	LL-G fault
3	Generic GFL BESS with NS[2] control	-0.9 pu, 0.5 pu and +0.9 pu		
4	Site-specific GFL BESS without NS control	-0.9 pu, 0.5 pu and +0.9 pu		
5	Site-specific GFL BESS with NS control	-0.9 pu, 0.5 pu and +0.9 pu		
6	Type 3 wind farm	0.9 pu and 0.5 pu		
7	Type 4 wind farm	0.9 pu and 0.5 pu		
8	Type 4 wind farm with NS control	0.9 pu and 0.5 pu		
9	Generic GFM BESS without NS control	-0.9 pu, 0.5 pu and +0.9 pu		
10	Generic GFM BESS with NS control	-0.9 pu, 0.5 pu and +0.9 pu		
11	Site-specific GFM BESS	-0.9 pu, 0.5 pu and +0.9 pu		
12	Generic GFM Solar (droop)	0.9 pu and 0.5 pu		
13	Generic GFM Solar (VSM)	0.9 pu and 0.5 pu		

3.1.2 Results and discussion

This section summarises the principal findings and provides a detailed evaluation of the performance of GFL and GFM inverters under negative-sequence conditions. Although the primary objective is to assess GFL and GFM behaviour in such scenarios, the dynamic response of a synchronous generator under analogous conditions is also examined and used as a comparative benchmark.

[2] Negative sequence

Presentation of the results

A large number of power system simulations were performed to examine GFL and GFM behaviour under negative-sequence conditions; only key results are included in the main text. Unless stated otherwise, this section focuses on the L–G fault under weak-grid conditions (SCR = 3, X/R = 1). Phasors are reported using the same sequence and phasor measurement convention used for compliance testing (for example, a one-cycle moving DFT); phasor angles are rotated such that V_2 is aligned to 0° for ease of comparison, and phasor length indicates magnitude in per unit. Where needed, time-domain waveforms are provided to confirm response timing and current-limiting behaviour; summary findings are consolidated in tables for clarity. Results are derived from existing models and their native controls and are presented for comparative illustration only.

Synchronous generator

Although this section of the report aims to investigate the response from the GFL and GFM inverters to unbalanced voltage (negative-sequence) conditions, this sub-section provides information and details regarding the response from the synchronous generator to negative-sequence conditions.

From a protection standpoint, relay functions such as negative-sequence overcurrent (50Q/51Q), negative-sequence directional elements (67Q), and faulted phase selectors rely on the presence of sufficient I_2 with a predictable phase angle relative to V_2. Traditional relays assume that during faults, I_2 will be sizable and roughly in quadrature (90°) with V_2.

Figure 7 shows the relationship between negative-sequence current (I_2) and voltage V_2 of the synchronous generator during a line-to-ground fault near its connection point[3]. It demonstrates that the phase angle between these two quantities remains stable during the fault duration and the presence of a sizable magnitude of I_2. A similar observation was noted for the double line-to-ground (LL-G) fault, as shown in Figure 8. Although it is known that this response from the synchronous generator is largely immune to the connection point SCR and X/R ratio, for completeness, Figure 9 shows the relationship between the negative-sequence current (I_2) and the negative-sequence voltage (V_2) when the connection point SCR and X/R ratio are higher.

[3] It should be noted that the phasors have been shifted to align the negative-sequence voltage phasor with 0°. This helps to compare various results.

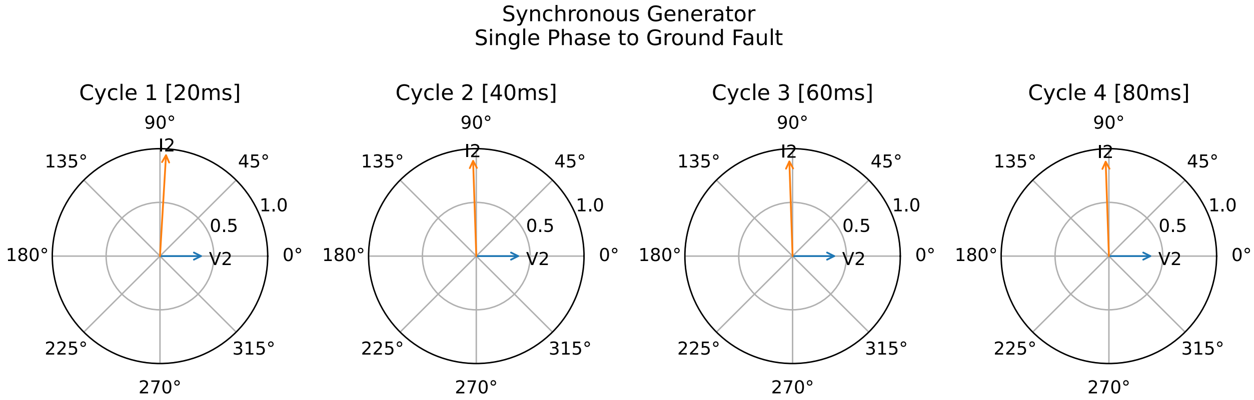

Figure 7 SG relationship (magnitude and angle) between V_2 and I_2 during the L-G fault for SCR = 3 and X/R = 1

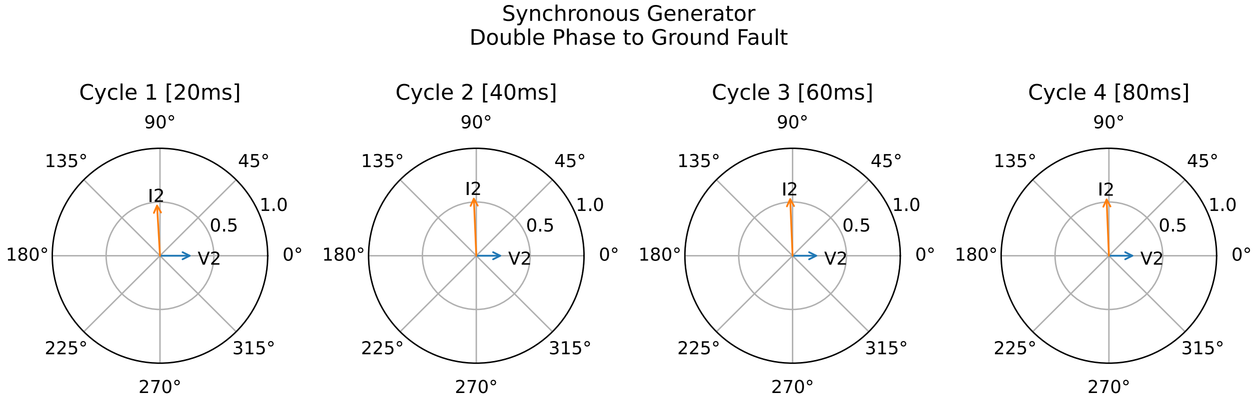

Figure 8 SG relationship (magnitude and angle) between V_2 and I_2 during the LL-G fault for SCR = 3 and X/R = 1

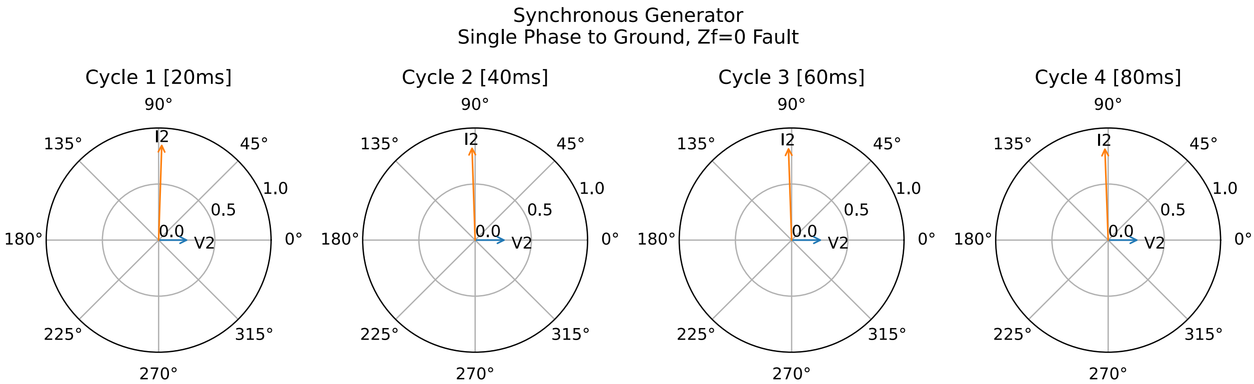

Figure 9 SG relationship (magnitude and angle) between V_2 and I_2 during the L-G fault for SCR = 10 and X/R = 10

Figure 10 to Figure 13 shows positive and negative voltage and current, which helps to determine effective negative-sequence impedance ($V_2\ /I_2$) during the fault and voltage unbalance factor ($V_2\ /V_1$).

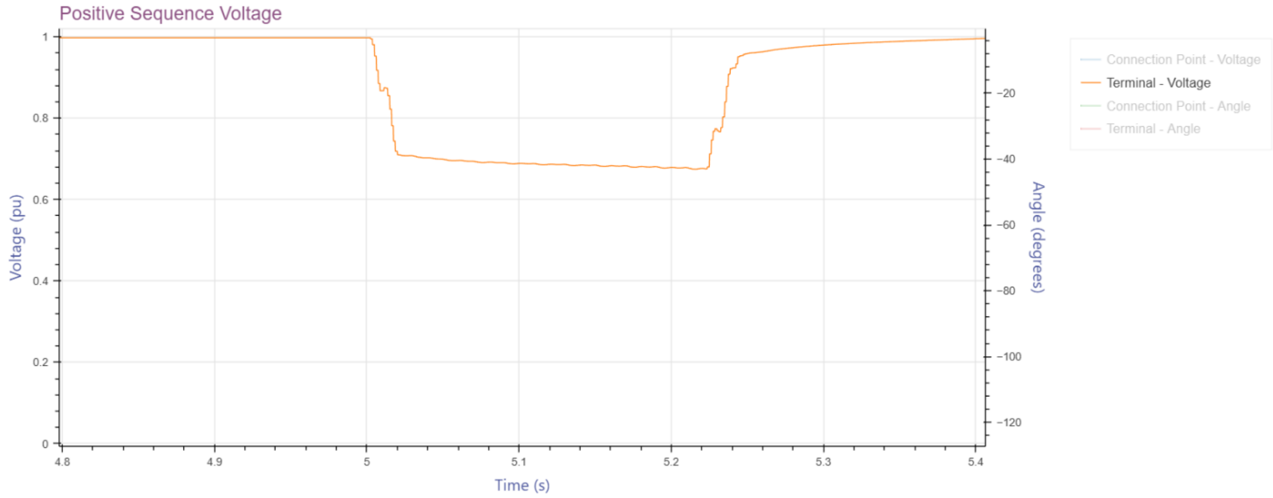

Figure 10 SG positive-sequence voltage during a L-G fault for SCR = 3 and X/R = 1

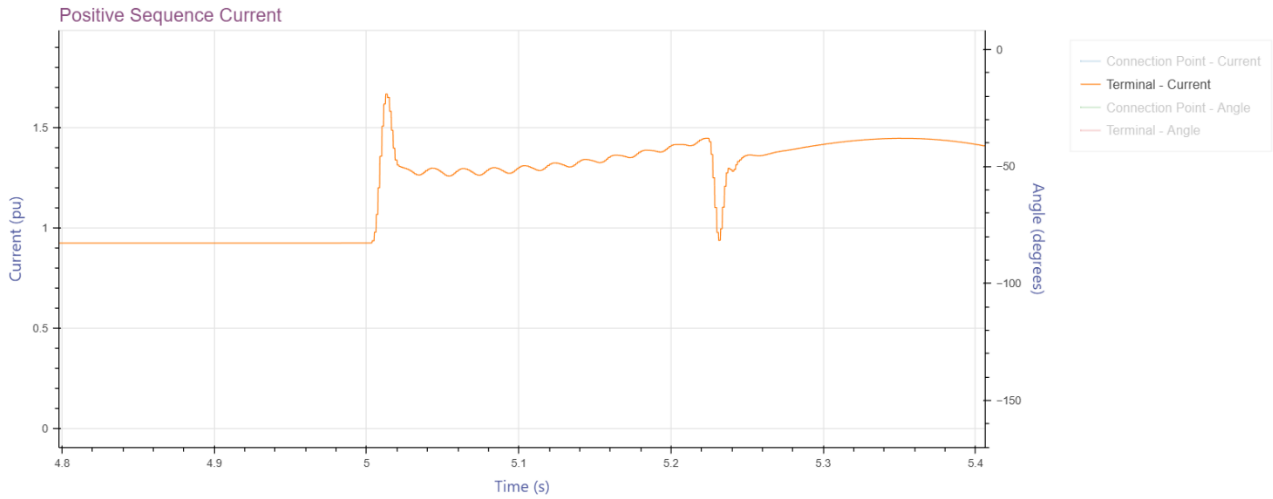

Figure 11 SG positive-sequence current during a L-G fault for SCR = 3 and X/R = 1

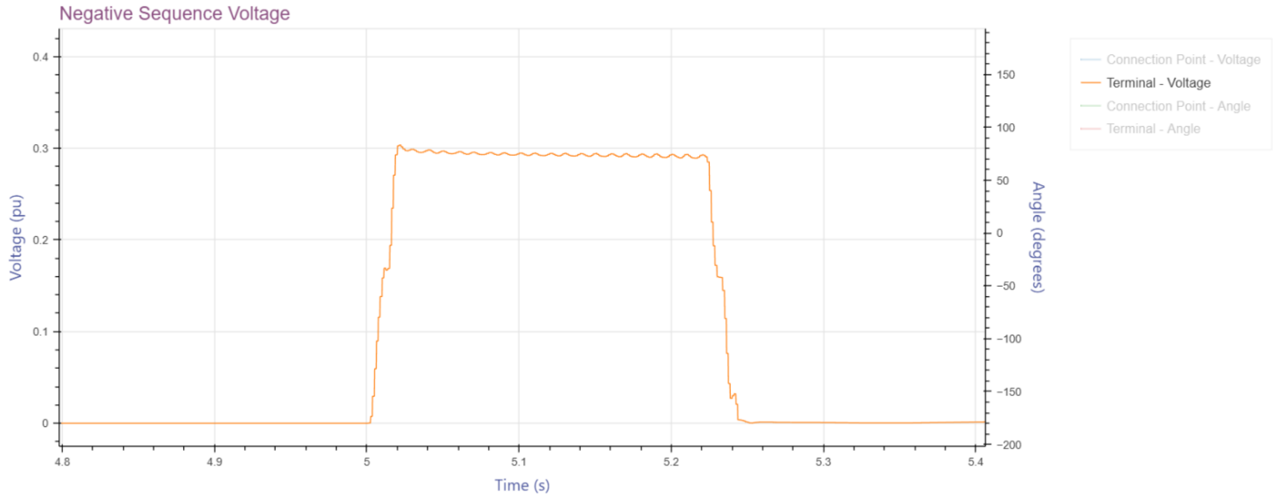

Figure 12 SG negative-sequence voltage during the L-G fault for SCR = 3 and X/R = 1

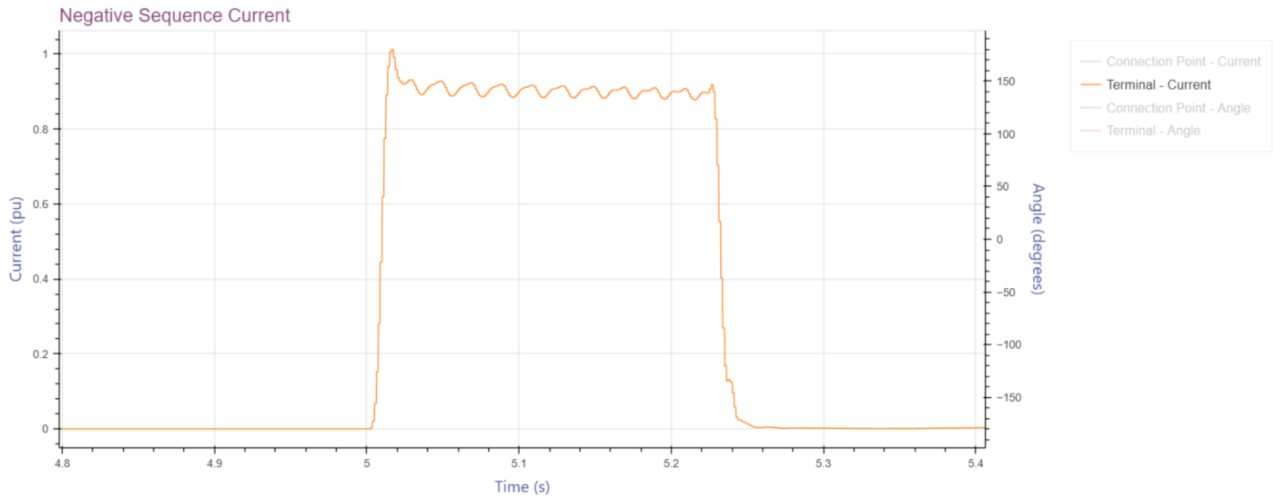

Figure 13 SG negative-sequence current during the L-G fault for SCR = 3 and X/R = 1

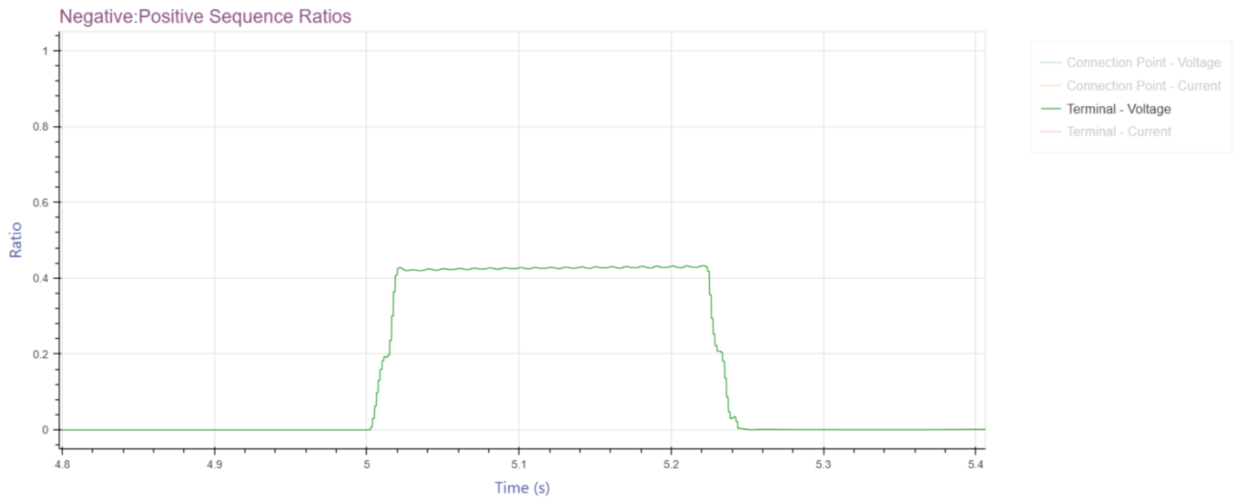

Figure 14 SG Voltage unbalance factor during the L-G fault for SCR = 3 and X/R = 1

Key observations

The following outlines key observations:

- Negative-sequence current leads negative-sequence voltage by approximately 90°. This is a desirable response from a protection standpoint.
- Fast, stable and sustained response throughout the disturbance. Within one cycle, phasors are stable and remain stable during the fault.
- Negative-sequence current is being injected into the grid.
- Effective negative-sequence impedance $V_2\ /I_2$ is stable and approximately 0.3 pu.
- Voltage unbalance factor $V_2\ /V_1$ is approximately 0.42

Building on the above key attributes (namely, phasor relationship, fast and stable response during fault, direction of negative-sequence current, effective negative-sequence impedance, and voltage unbalance factor), the following sections examine the responses of various IBRs and compare them with those of a synchronous generator under similar conditions.

Phasor relationship

Grid-following

Generic GFL BESS without NS control

Figure 15 to Figure 17 show the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic GFL BESS without NS control enabled. The test is carried out for three different initial operating points.

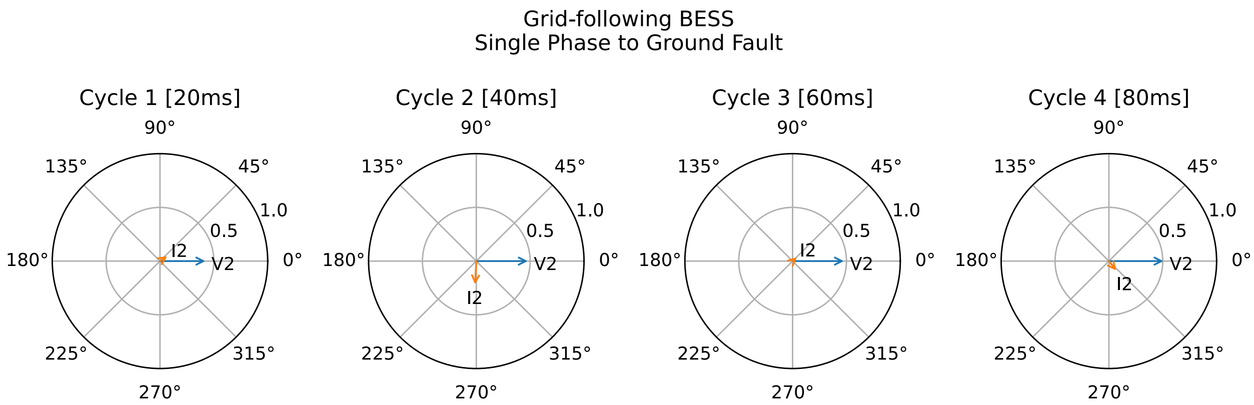

Figure 15 GFL BESS relationship between V_2 and I_2, for SCR = 3 and X/R = 1 (BESS at +0.9 pu)

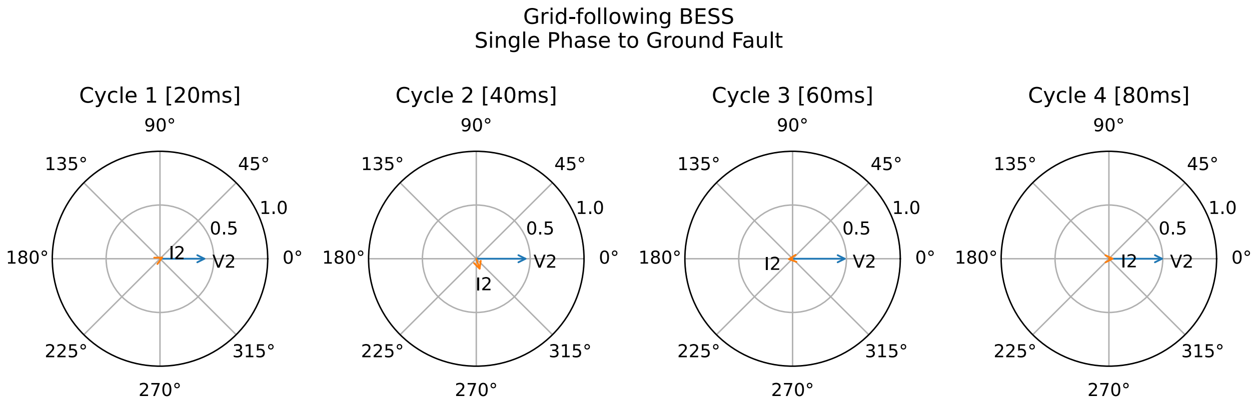

Figure 16 GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at 0 pu)

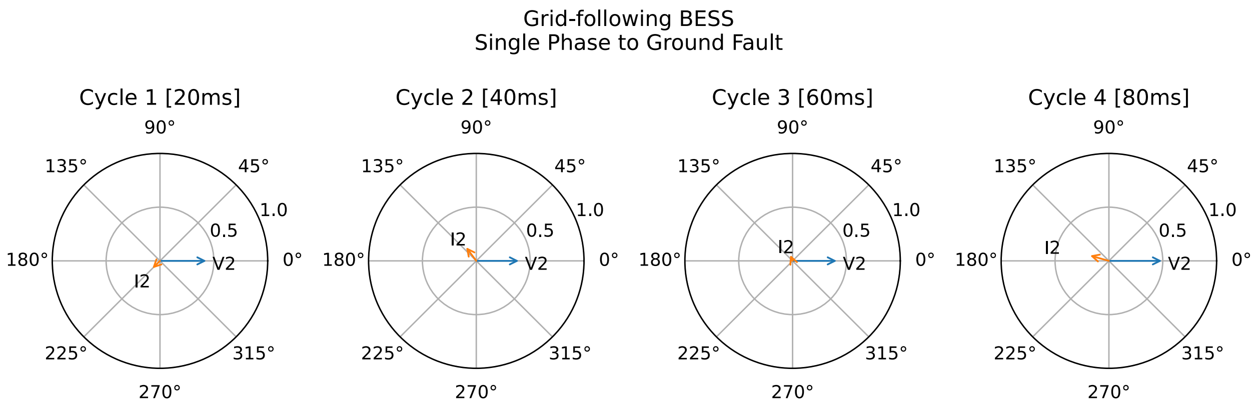

Figure 17 GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu)

Generic GFL BESS with NS control

Figure 18 to Figure 20 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic GFL BESS with NS control enabled. Three operating points are examined.

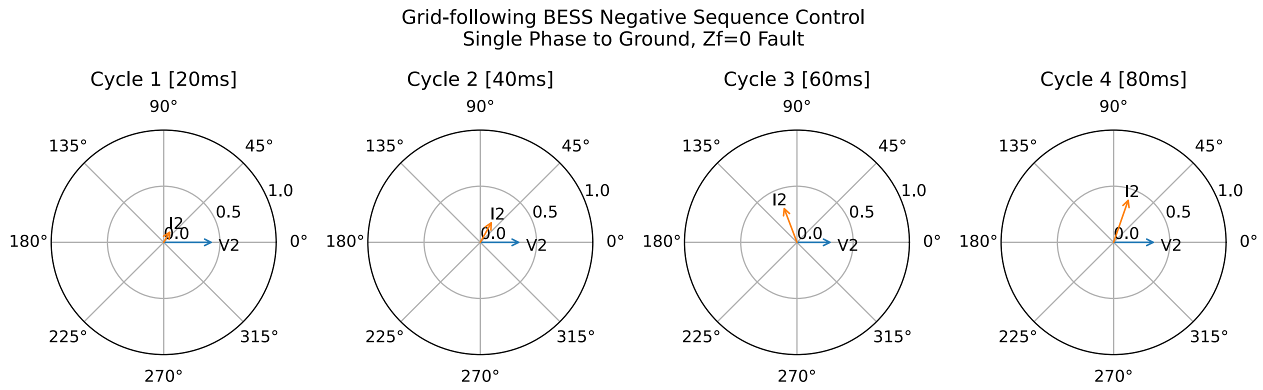

Figure 18 GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu) - NS control enabled

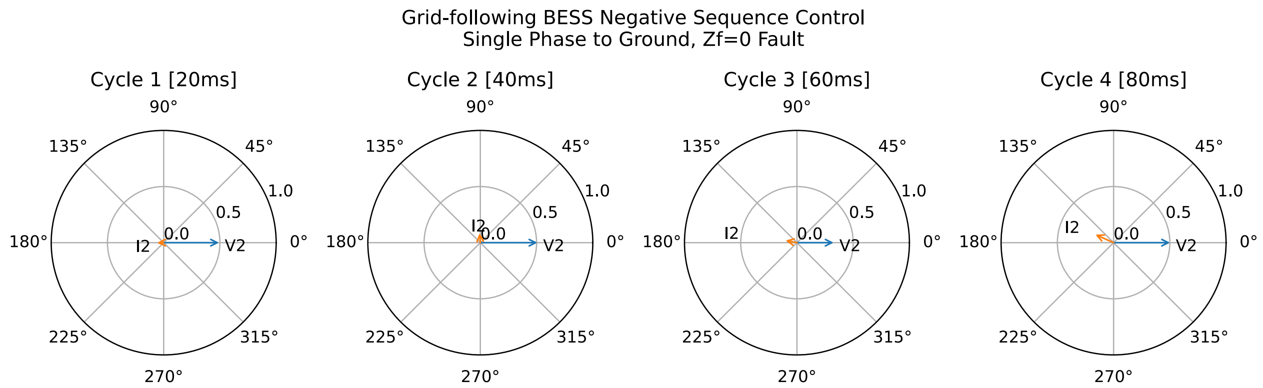

Figure 19 GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at 0.5 pu) - NS control enabled

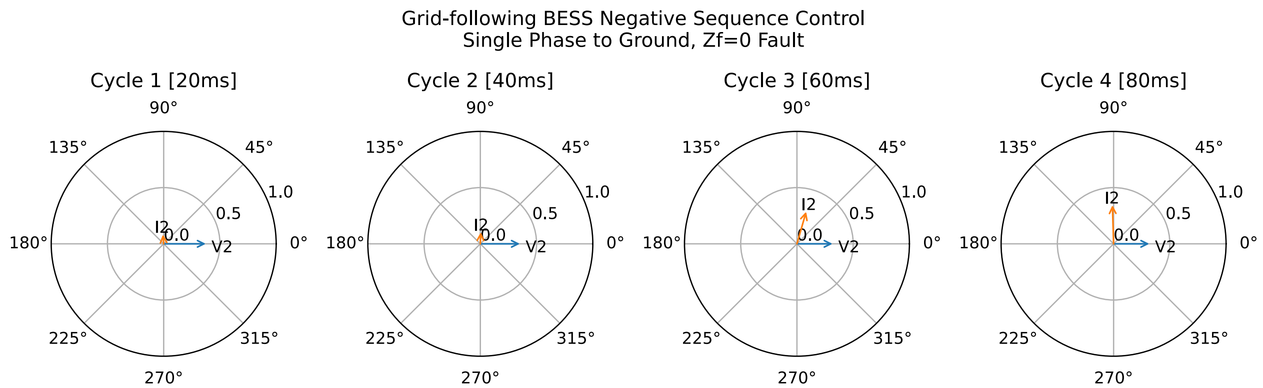

Figure 20 GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu) - NS control enabled

Site-specific GFL BESS without NS control (A09)

Figure 21 to Figure 23 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a site-specific GFL BESS without NS control enabled[4]. Three operating points are examined.

[4] The exact same k-factor (and negative sequence current reference derivation) was used between the GFL and GFM BESS, a value of 2.0.

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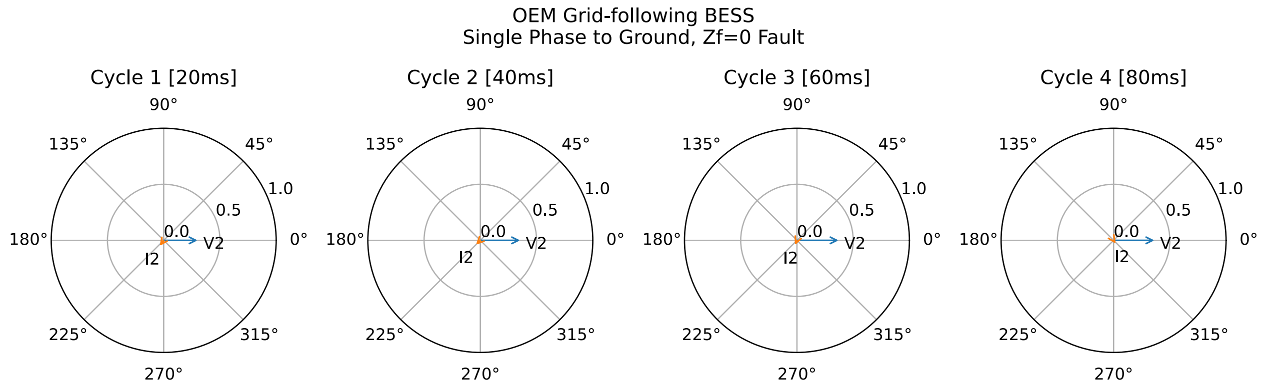


Figure 21 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu)

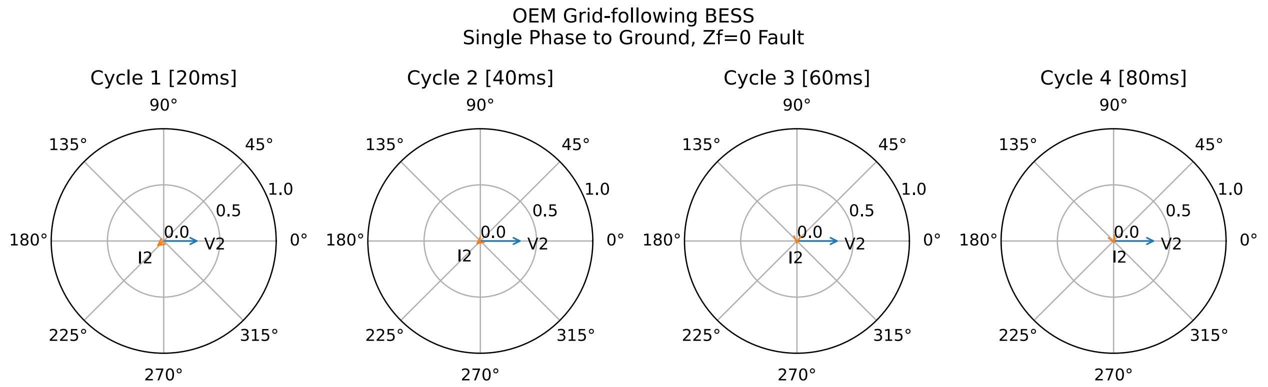


Figure 22 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0 pu)

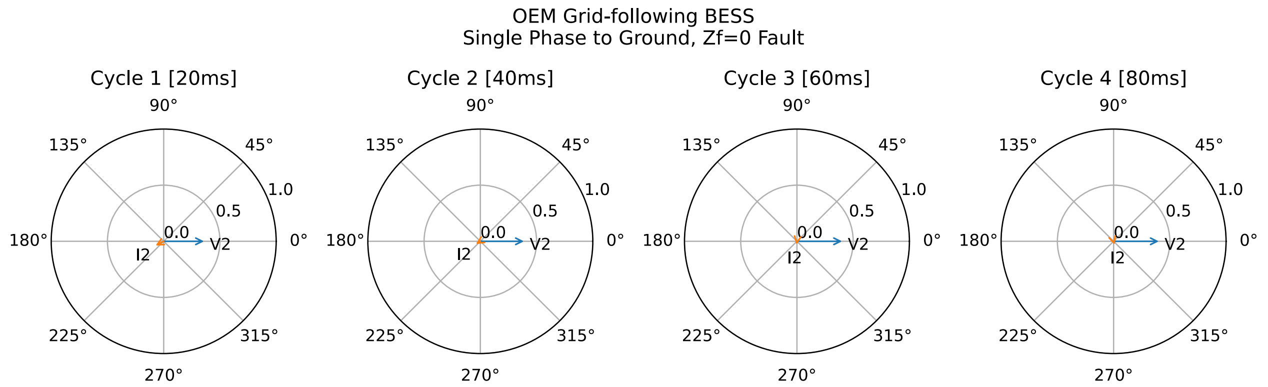


Figure 23 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu)

Site-specific GFL BESS with NS control (A10)

Figure 21 to Figure 23 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a site-specific GFL BESS with NS control enabled. Three operating points are examined.

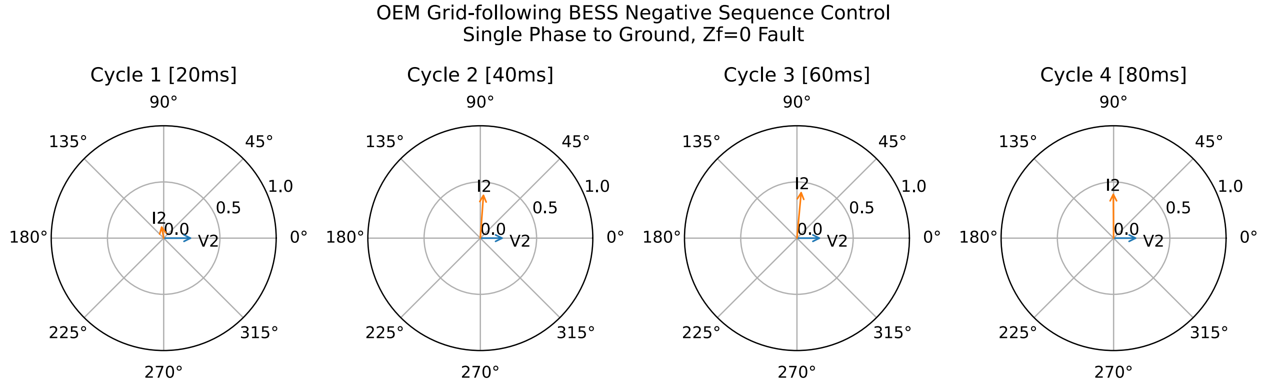


Figure 24 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu) - NS control enabled

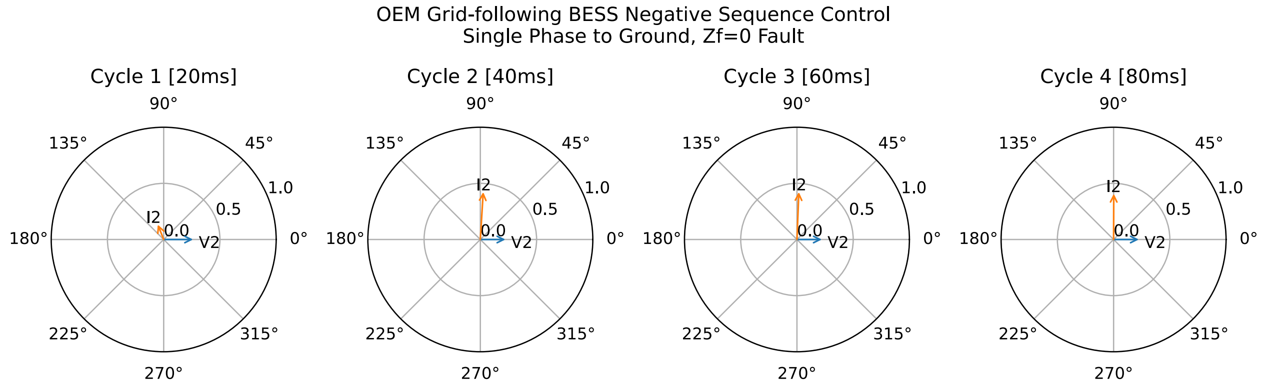


Figure 25 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.5 pu) - NS control enabled

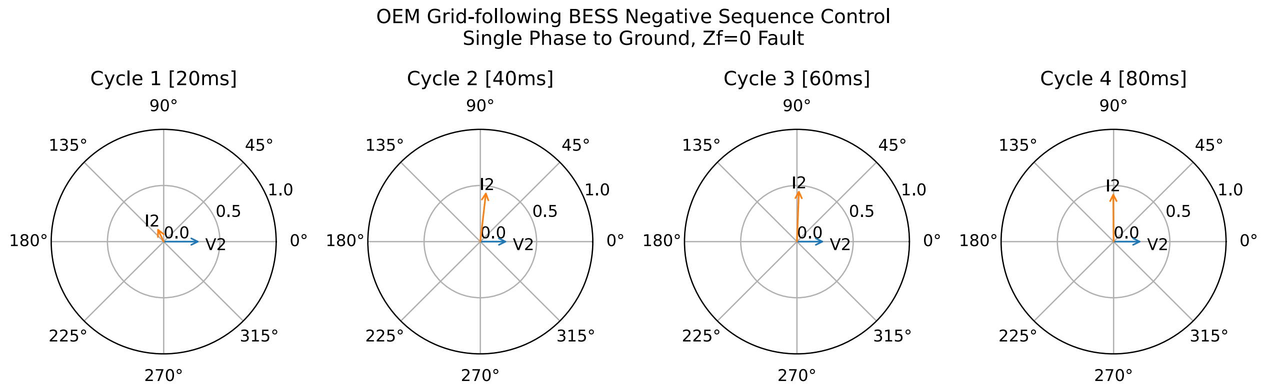


Figure 26 Site-specific GFL BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu) - NS control enabled

Type 3 Windfarm

Figure 27 and Figure 28 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic type 3 WF without NS control enabled. Two operating points are examined.

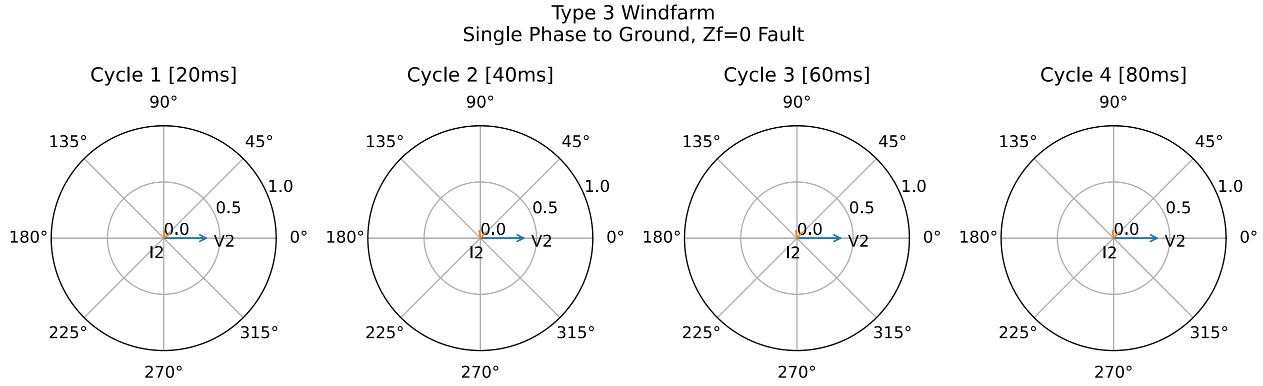


Figure 27 Type 3 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.9pu)

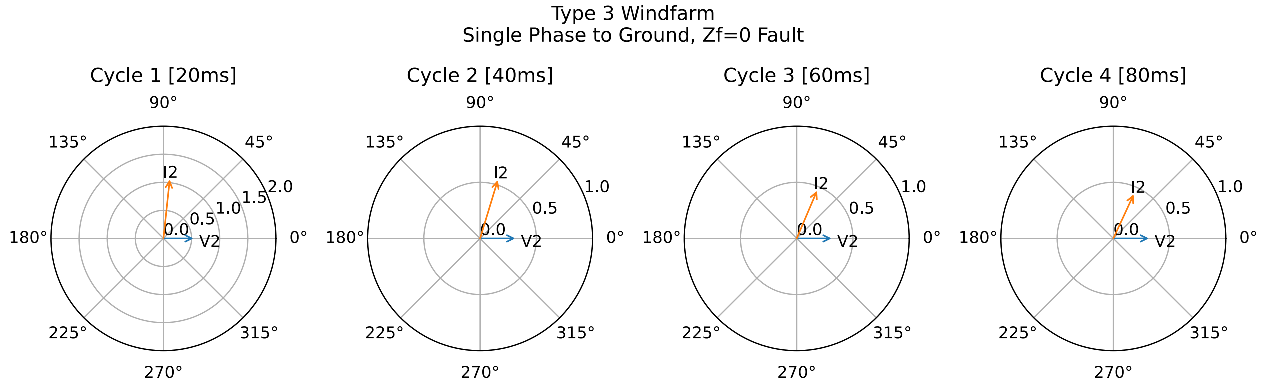


Figure 28 Type 3 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.5pu)

Type 4 Windfarm[5]

Figure 29 and Figure 30 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic type 4 WF without NS control enabled. Two operating points are examined.

[5] GFL type 4 WF

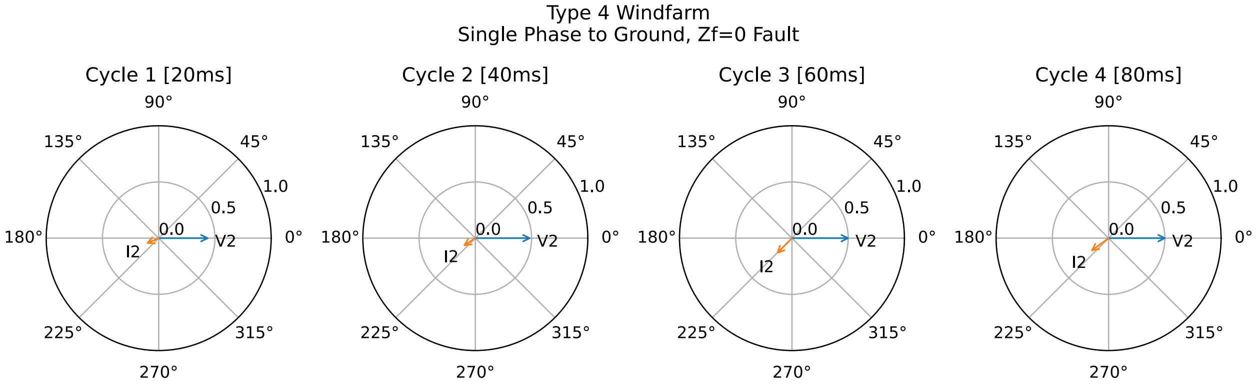


Figure 29 Type 4 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.9pu)

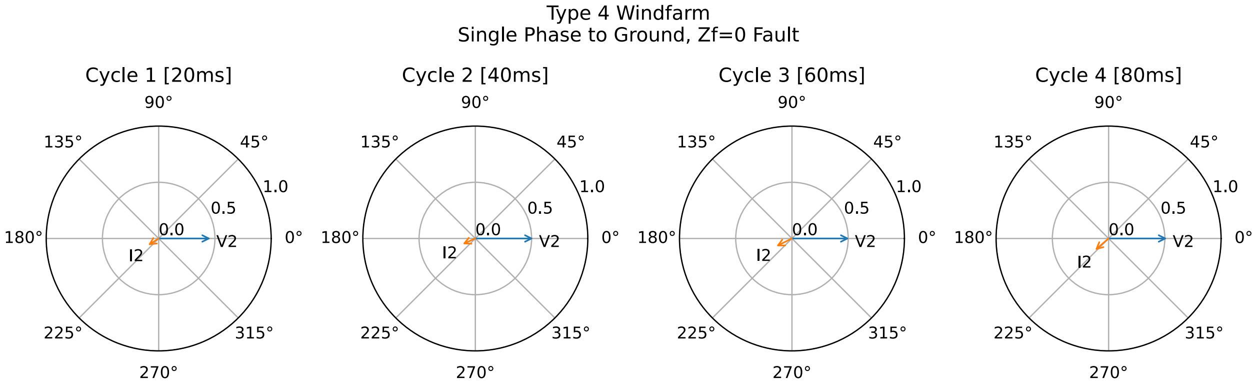


Figure 30 Type 4 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.5pu)

Type 4 Windfarm with NS control

Figure 31 and Figure 32 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic type 4 WF with NS control enabled. Two operating points are examined.

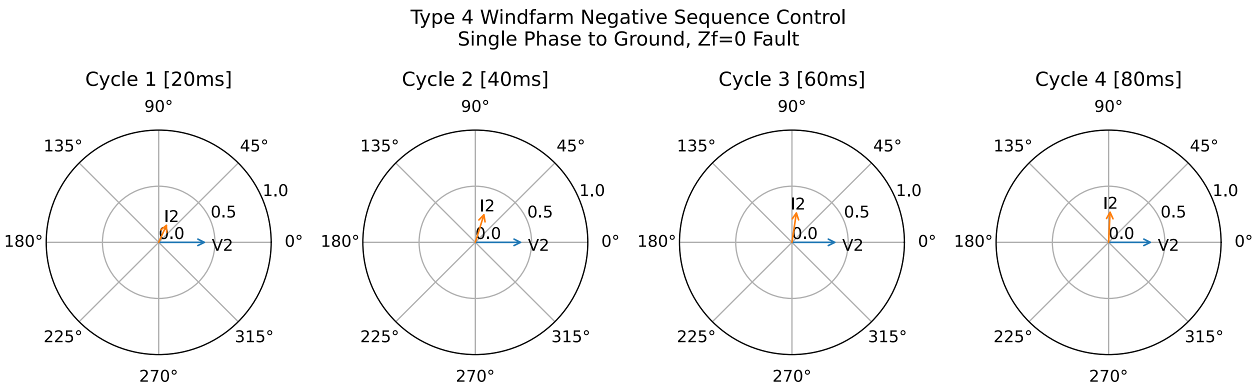


Figure 31 Type 4 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.9pu) – Negative-sequence control enabled

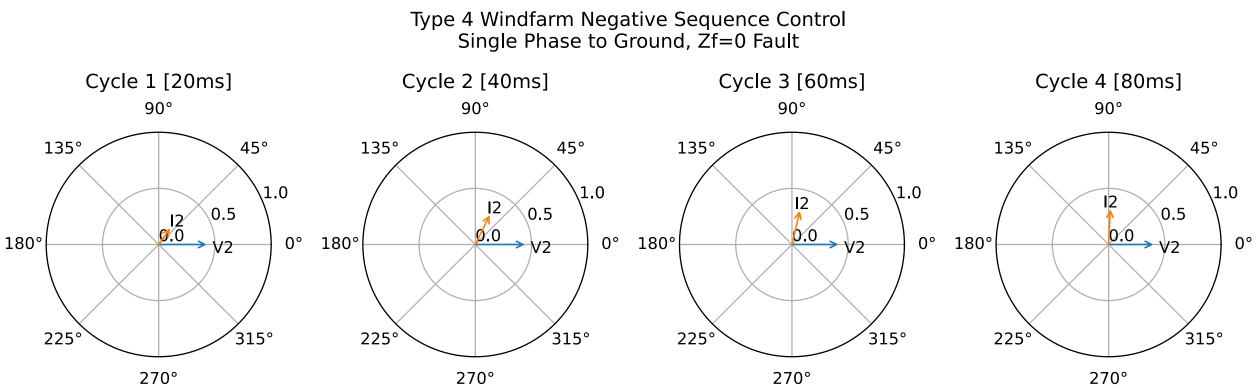


Figure 32 Type 4 WF relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (WF at +0.5pu) – Negative-sequence control enabled

Key observations

The following are key observations:

- Site-specific GFL BESS with negative-sequence control enabled, and type 4 WF with negative-sequence control enabled, provide a closer to 90° reactive (leading) relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2). Other GFL IBR analyses have not shown this desired behaviour.
- For the plants that provide stable phasors during fault duration, they achieve these stable phenomena after 40ms only. Not yet confirmed, but this could be attributed to a simulation measurement artefact.

Grid-forming

Generic GFM BESS (A03)

Figure 33 to Figure 35 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic GFM BESS without NS control enabled. Three operating points are examined.

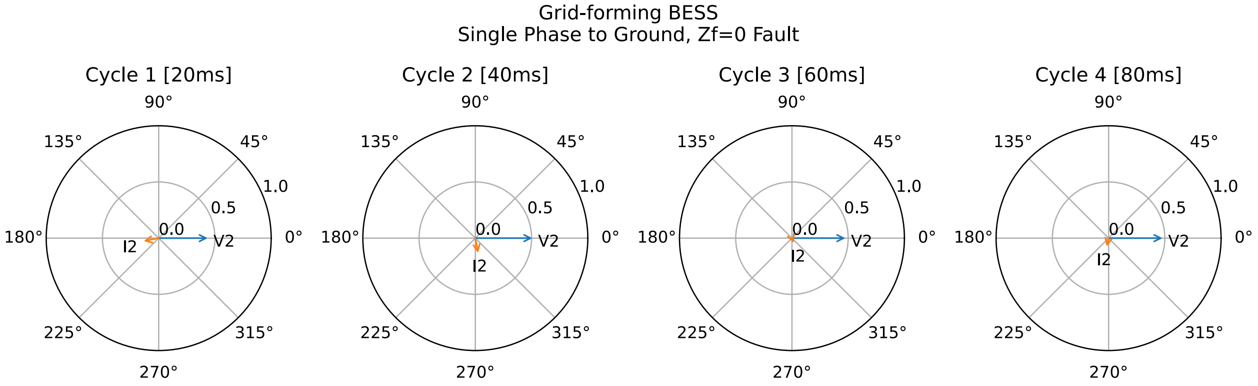


Figure 33 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu)

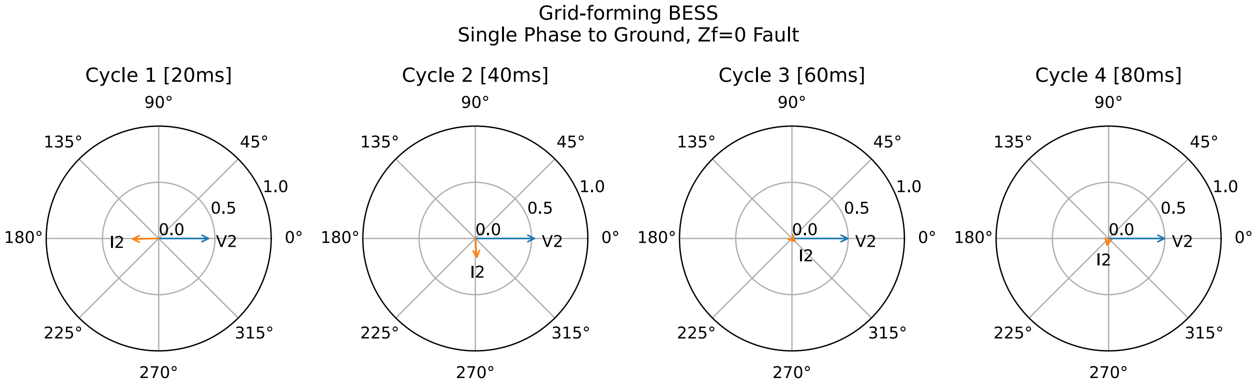


Figure 34 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.5 pu)

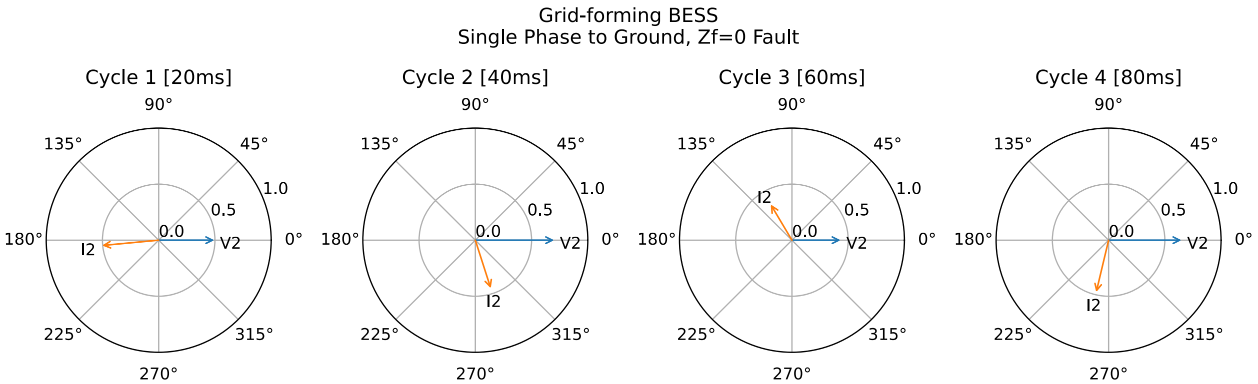


Figure 35 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu)

Generic GFM BESS with NS control enabled (A04)

Figure 36 to Figure 38 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic GFM BESS with NS control enabled. Three operating points are examined.

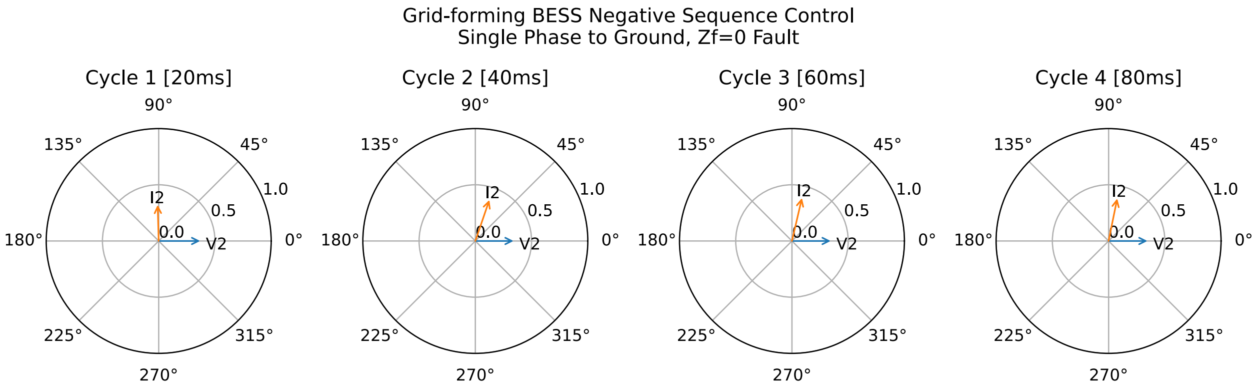


Figure 36 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu) - with NS control enabled

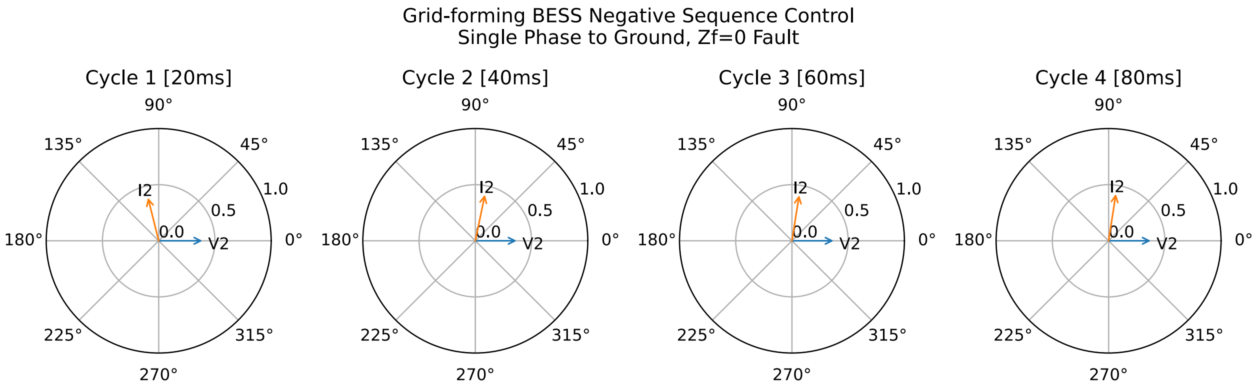


Figure 37 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.5 pu) - with NS control enabled

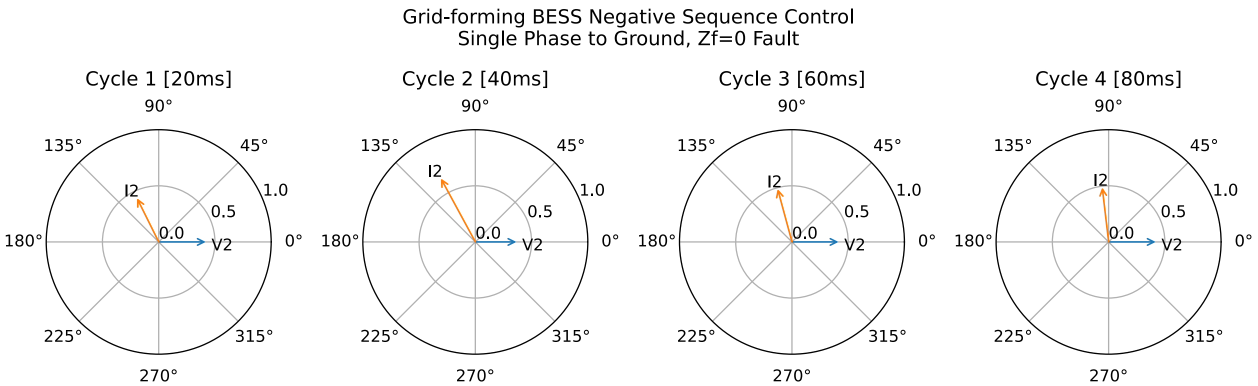


Figure 38 GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu) - with NS control enabled

Site-specific GFM BESS (A11)

Figure 39 to Figure 41 shows relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a site-specific GFM BESS. Three operating points are examined.

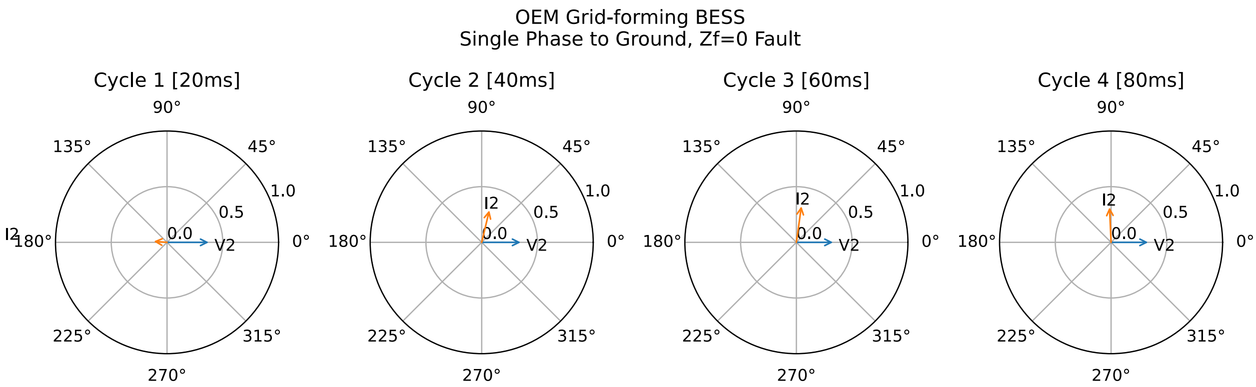


Figure 39 Site-specific GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.9 pu)

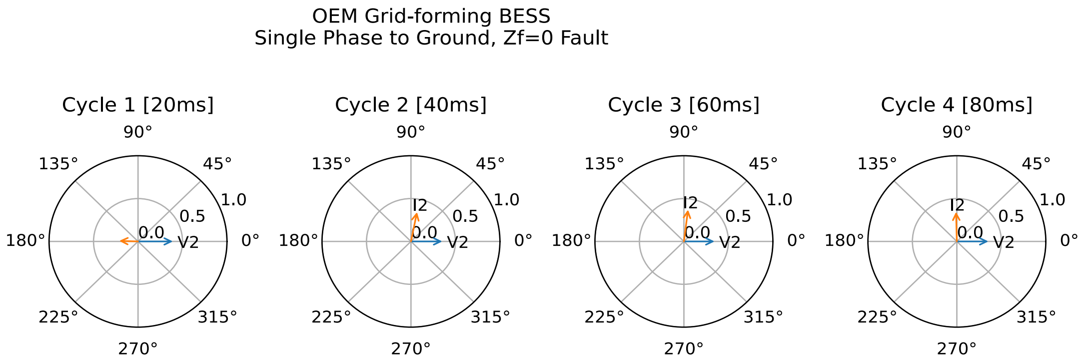


Figure 40 Site-specific GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at +0.5 pu)

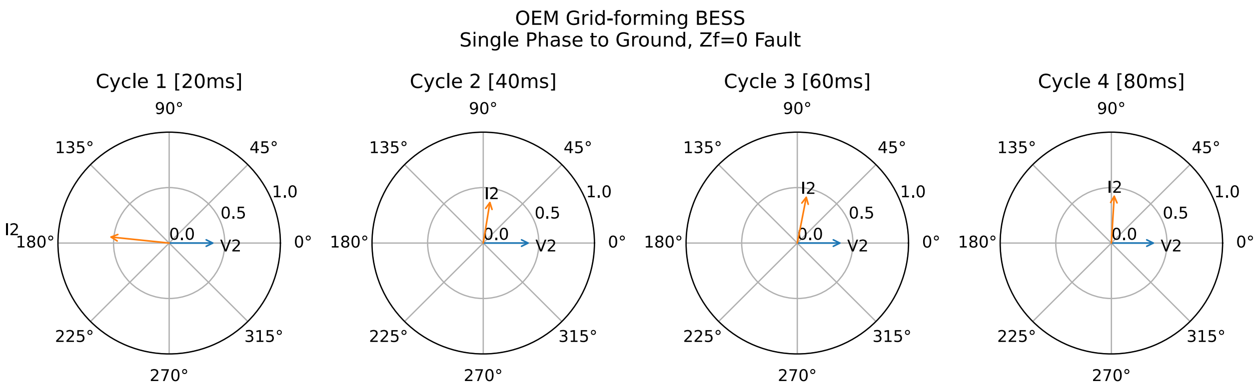


Figure 41 Site-specific GFM BESS relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (BESS at -0.9 pu)

Generic GFM Solar Farm

Figure 42 to Figure 45 shows the relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2) for a generic GFM Solar Farm. Two operating points are examined

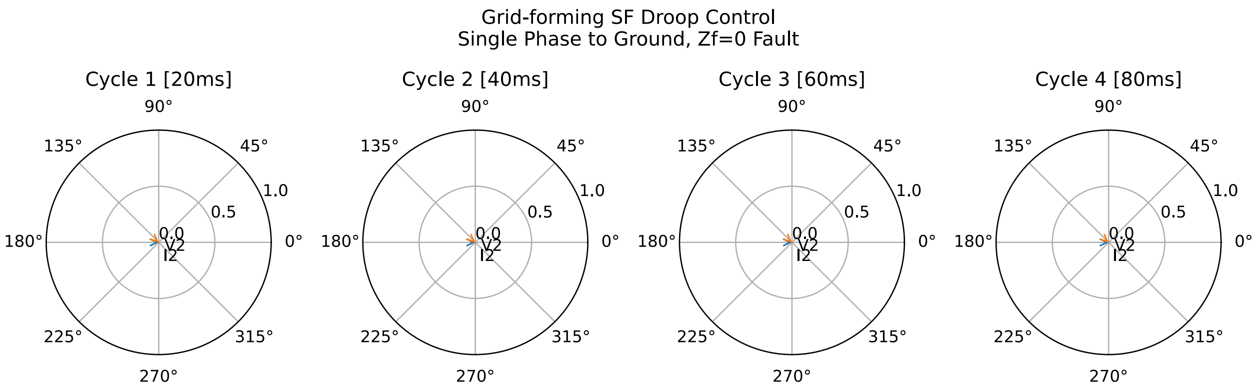


Figure 42 Generic GFM SF (droop mode) relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (SF at +0.9 pu)

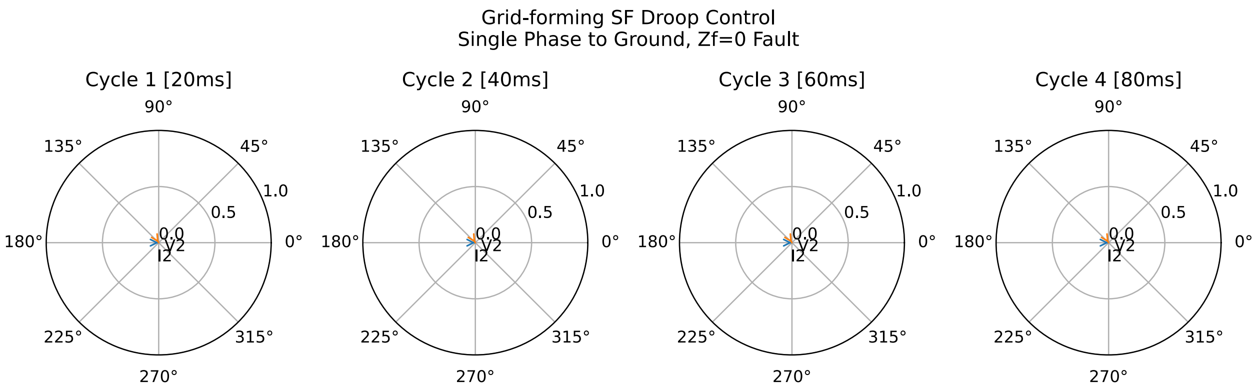


Figure 43 Generic GFM SF (droop mode) relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (SF at +0.5 pu)

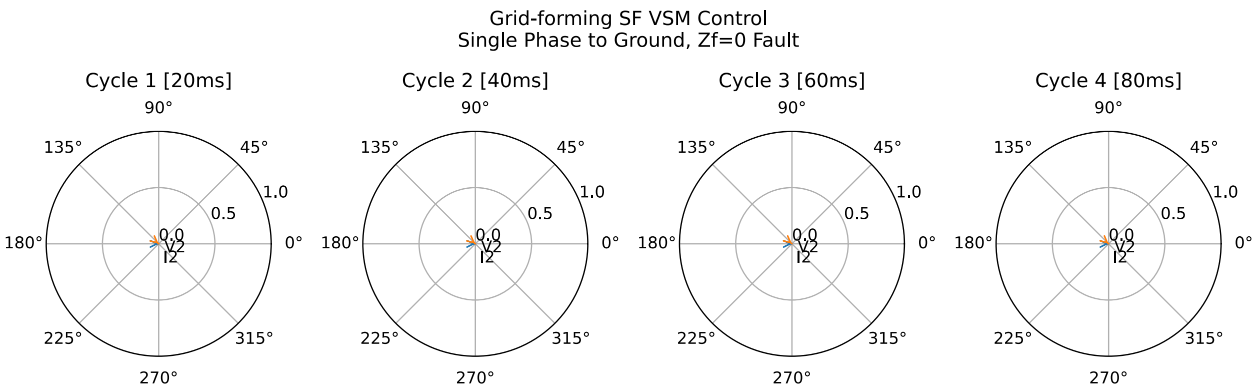


Figure 44 Generic GFM SF (VSM mode) relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (SF at +0.9 pu)

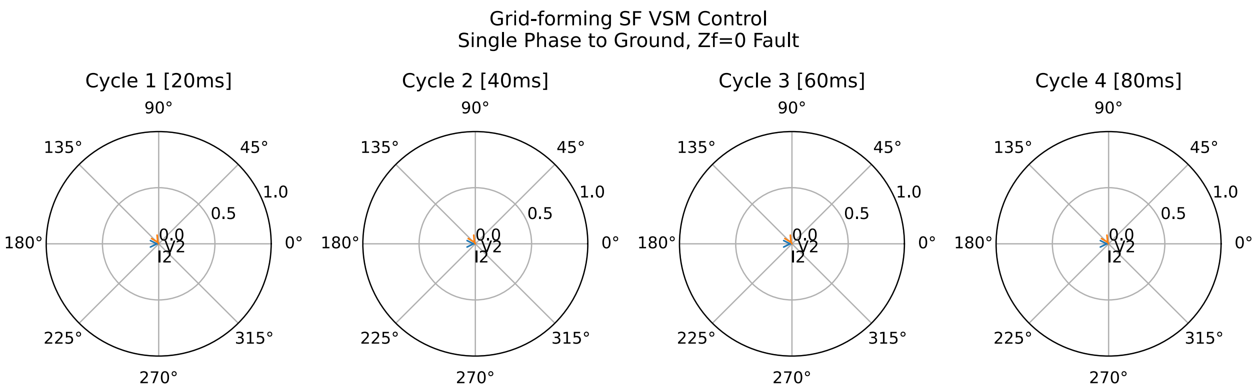


Figure 45 Generic GFM SF (VSM mode) relationship between V_2 and I_2 for SCR = 3 and X/R = 1 (SF at +0.5 pu)

Key observations

The following are key observations:

- Site-specific GFM BESS provides a closer to 90° reactive (leading) relationship between negative-sequence current (I_2) and negative-sequence voltage (V_2). Other GFM IBR analyses have not shown this desired behaviour
- For the plants that provide stable phasors during fault duration, they achieve these stable phenomena after 40ms only. Not yet confirmed, but this could be attributed to a simulation measurement artefact.

Summary

Based on the key observations outlined in section 3.1.2, Table 11 provides a summary of the analysis focusing on the negative-sequence phasor relationship.

Table 11 Summary of negative-sequence phasor relationship

Sr No	Technology	Acceptable angle difference	Fast and stable phasor response during the fault
1	Synchronous machine	Acceptable	Acceptable
2	Generic GFL BESS without NS control	Not acceptable	Not acceptable
3	Generic GFL BESS with NS control	Not acceptable	Not acceptable
4	Site-specific GFL BESS without NS control	Not acceptable	Not acceptable
5	Site-specific GFL BESS with NS control	Acceptable*	Acceptable*
6	Type 3 wind farm	Not acceptable	Not acceptable
7	Type 4 wind farm	Not acceptable	Not acceptable
8	Type 4 wind farm with NS control	Acceptable*	Acceptable*
9	Generic GFM BESS without NS control	Not acceptable	Not acceptable
10	Generic GFM BESS with NS control[6]	Not acceptable	Not acceptable
11	Site-specific GFM BESS	Acceptable*	Acceptable*
12	Generic GFM Solar (droop)	Not acceptable	Not acceptable
13	Generic GFM Solar (VSM)	Not acceptable	Not acceptable

* after 40 ms

Absorbing vs injecting negative-sequence current

This section indicates whether each IBR injects negative-sequence current into the grid or absorbs it from the grid. For protection dependability, it is generally preferable that IBRs inject a predictable, predominantly reactive I_2 during faults. In this report, injection versus absorption is classified using the measured phasor angle $\angle(I_2) - \angle(V_2)$and, where helpful, the sign of derived negative-sequence reactive power Q_2. Time-domain direction plots are used only as a consistency

[6] Sequence-controlled GFM was the algorithm used (Sequence-controlled GFM in Section 2.3).

check for the adopted sign convention (device → grid positive), not as the primary criterion for injection versus absorption.

Figure 46 to Figure 48 shows sample time domain results to identify the direction of negative-sequence current.

Table 12 provides a summary of the results.

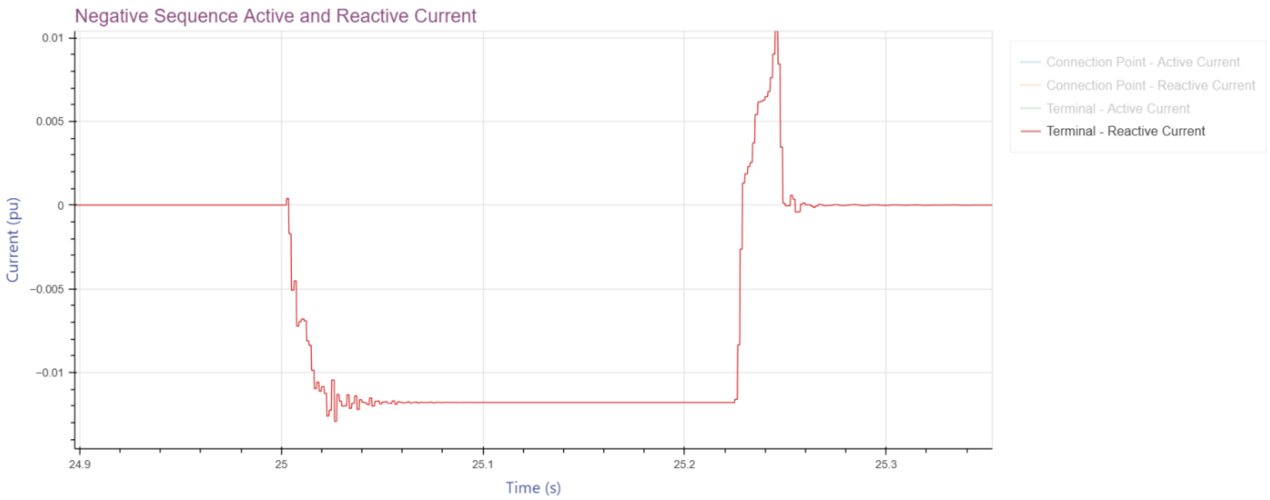


Figure 46 Type 3 WF negative-sequence current

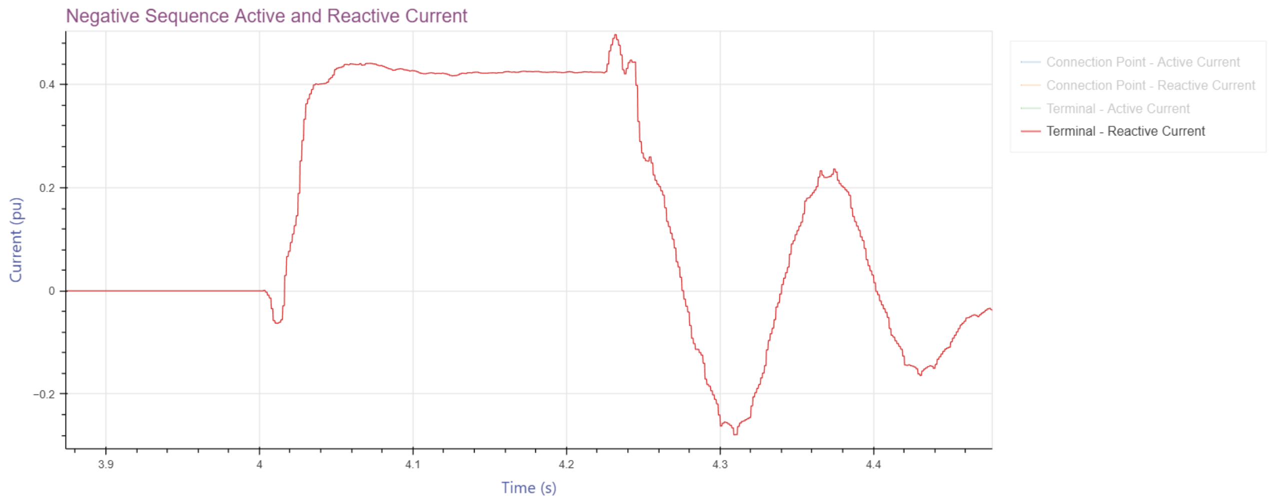


Figure 47 Generic GFM BESS without NS control – negative-sequence current

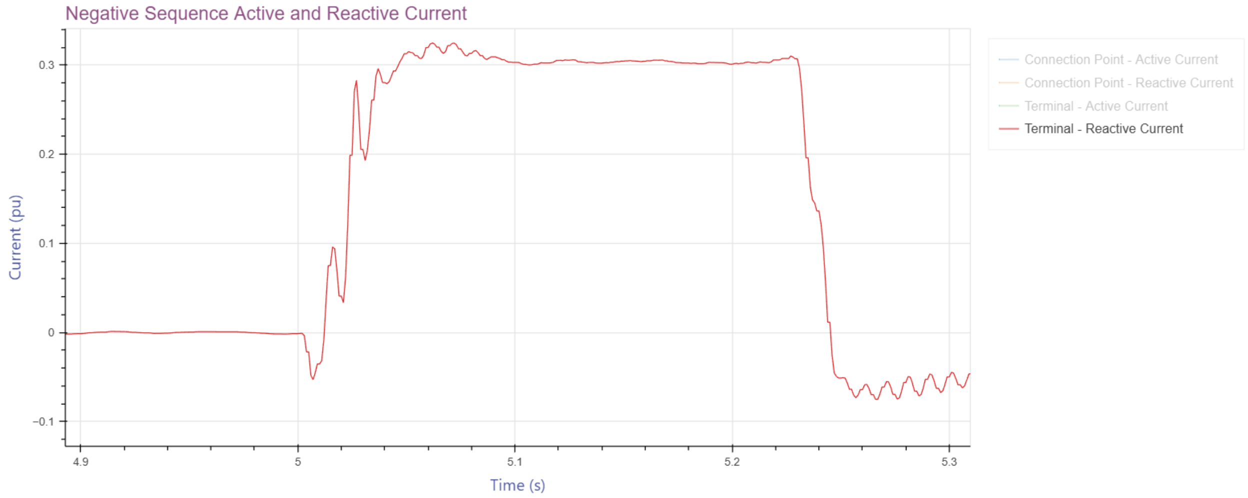


Figure 48 Site-specific GFM BESS – negative-sequence current

Table 12 Negative-sequence current injection into or absorption from the grid

Sr No	Technology	Negative-sequence current injecting into the grid / Absorbing from the grid	Direction plot consistent with sign convention?
1	Synchronous machine	Injecting	Acceptable
2	Generic GFL BESS without NS control	Absorbing	Not Acceptable
3	Generic GFL BESS with NS control	Injecting	Acceptable
4	Site-specific GFL BESS without NS control	Injecting	Acceptable
5	Site-specific GFL BESS with NS control	Injecting	Acceptable
6	Type 3 wind farm	Absorbing	Acceptable
7	Type 4 wind farm	Briefly injecting but mostly absorbing	Not Acceptable
8	Type 4 wind farm with NS control	Injecting	Acceptable
9	Generic GFM BESS without NS control	injecting	Acceptable
10	Generic GFM BESS with NS control	injecting	Acceptable
11	Site-specific GFM BESS	Injecting	Acceptable
12	Generic GFM Solar (droop)	Absorbing	Not Acceptable
13	Generic GFM Solar (VSM)	Injecting	Not Acceptable

Effective negative- and positive-sequence impedance

This section provides time-domain simulation results for some IBRs. Negative-sequence voltage and current are plotted to show the time-based response and capture variability.

Figure 49 to Figure 54 shows time domain results for some IBRs. Table 13 provides a summary of the results. For completeness, values of positive-sequence impedances are also tabulated.

It is desirable that the effective negative-sequence impedance and the effective positive-sequence impedance be similar, as this will help achieve the required phase balance during fault conditions.

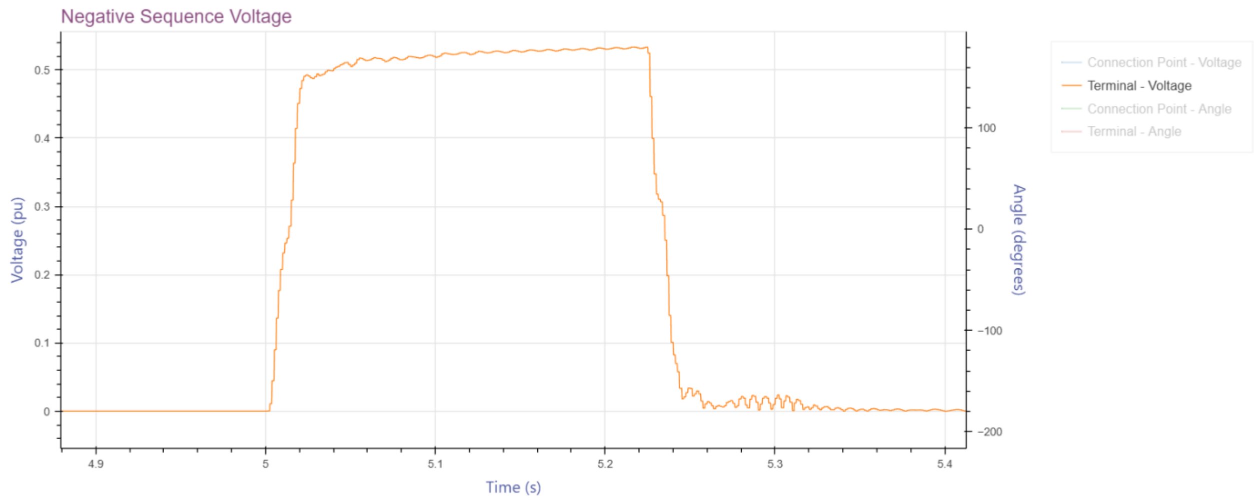


Figure 49 Type 4 WF negative-sequence voltage

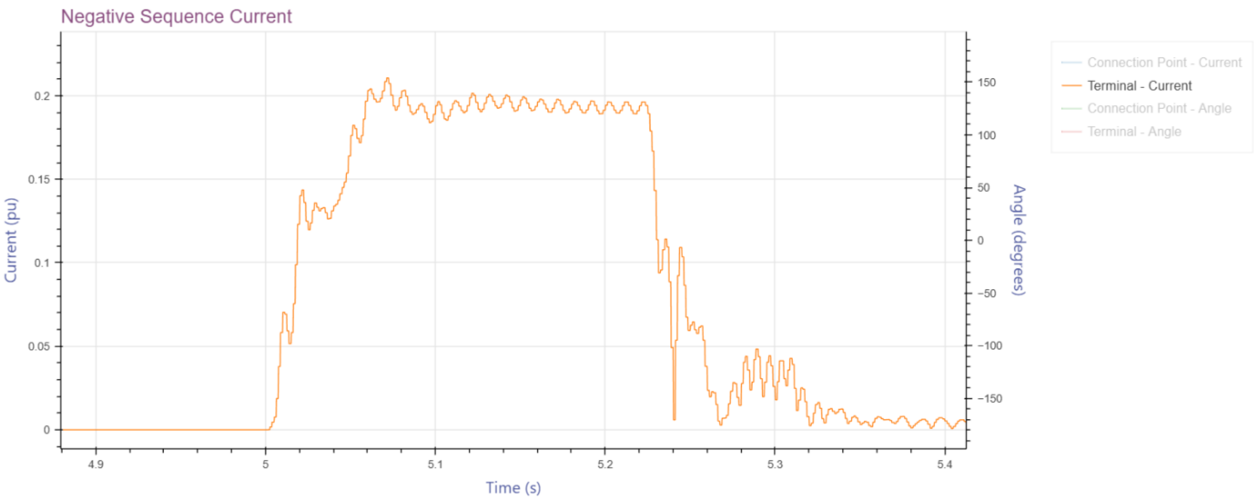


Figure 50 Type 4 WF negative-sequence current

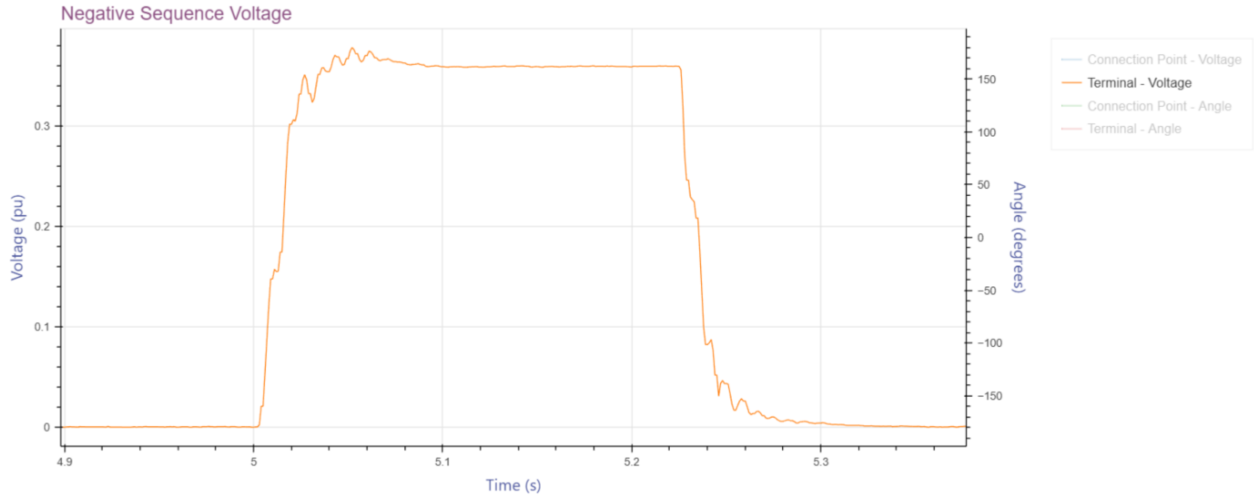


Figure 51 Site-specific GFL BESS without NS control: Negative-sequence voltage

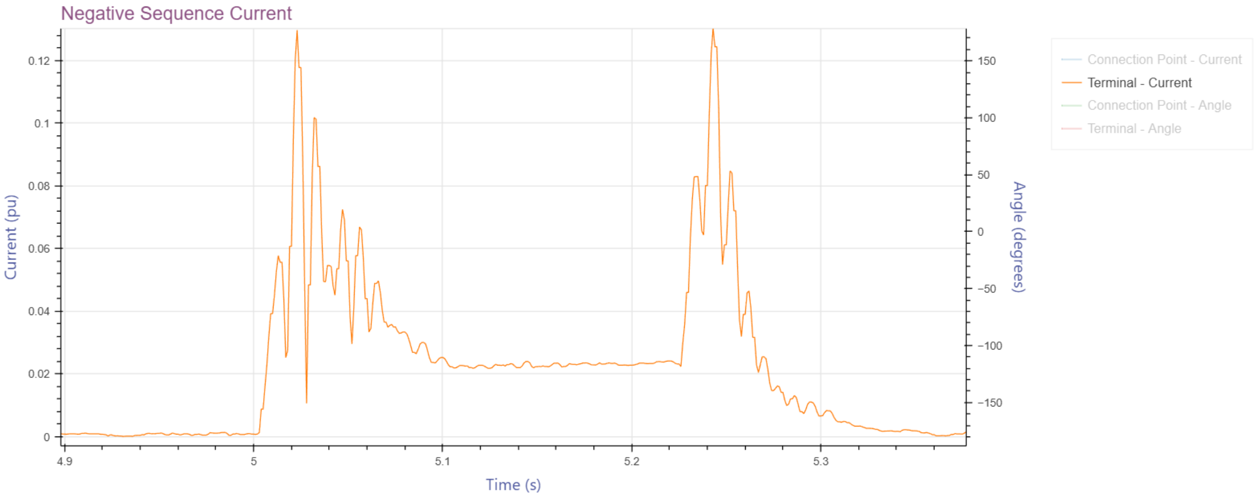


Figure 52 Site-specific GFL BESS without NS control: Negative-sequence current

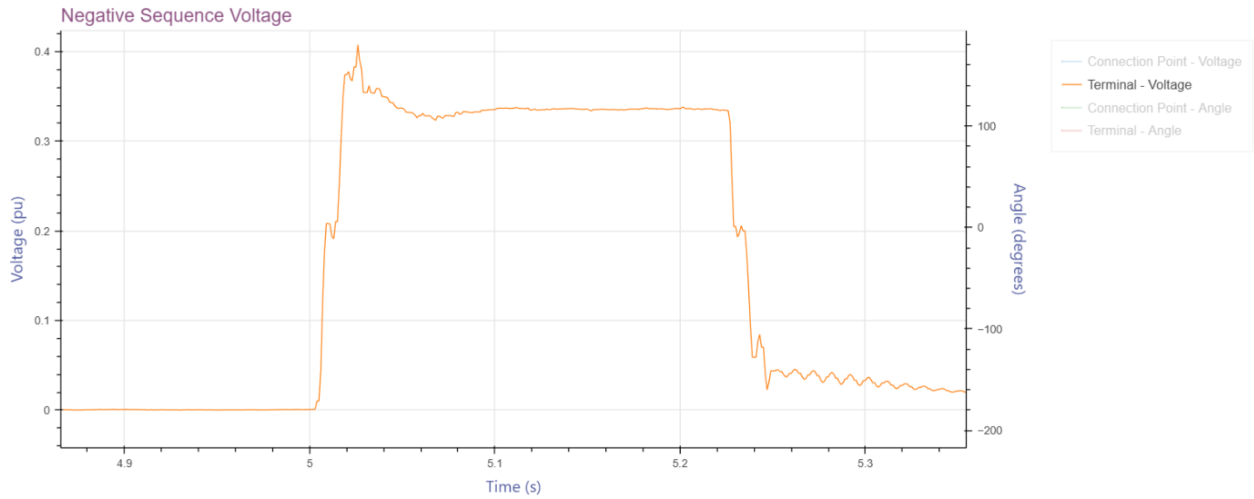


Figure 53 Site-specific GFM BESS: Negative-sequence-voltage

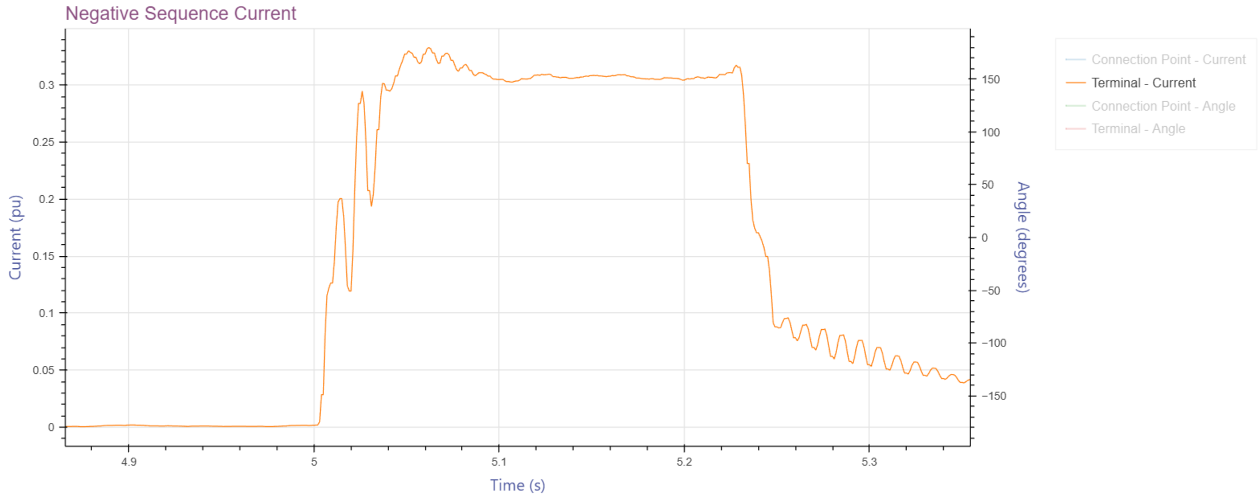


Figure 54 Site-specific GFM BESS: Negative-sequence current

Table 13 Effective negative- and positive-sequence impedance

Sr No	Technology	Effective negative-sequence impedance (calculated from time domain response around 40ms)	Effective positive-sequence impedance (calculated from time domain response around 40ms)
1	Synchronous machine	0.30, stable	0.54, stable
2	Generic GFL BESS without NS control	Highly variable, cannot be determined	
3	Generic GFL BESS with NS control	Around 1.5, reduces to around 1 quickly and remains stable	0.68 and largely stable during the fault duration
4	**Site-specific GFL BESS without NS control**	**Highly variable, cannot be determined**	**1.1, stable**
5	Site-specific GFL BESS with NS control	Around 0.5, largely stable during the fault duration	Around 1.12, stable
6	Type 3 wind farm	Around 28	Around 27
7	**Type 4 wind farm**	**2.5, generally stable after 3 cycles**	**0.62, generally stable**
8	Type 4 wind farm with NS control	1.52, generally stable after 3 cycles	0.53, generally stable
9	Generic GFM BESS without NS control	Highly variable, cannot be determined	Around 0.62, generally stable
10	Generic GFM BESS with NS control	0.84, generally stable	0.75, generally stable
11	**Site-specific GFM BESS**	**1.15**	**1.1**
12	Generic GFM Solar droop	0.5, stable	0.9, stable
13	Generic GFM Solar VSM	0.5, stable	0.9, stable

Voltage unbalance factor

Figure 55 to Figure 56 shows the time domain response for the ratio between negative-sequence voltage and negative-sequence current. Table 14 shows the summary of the simulation results.

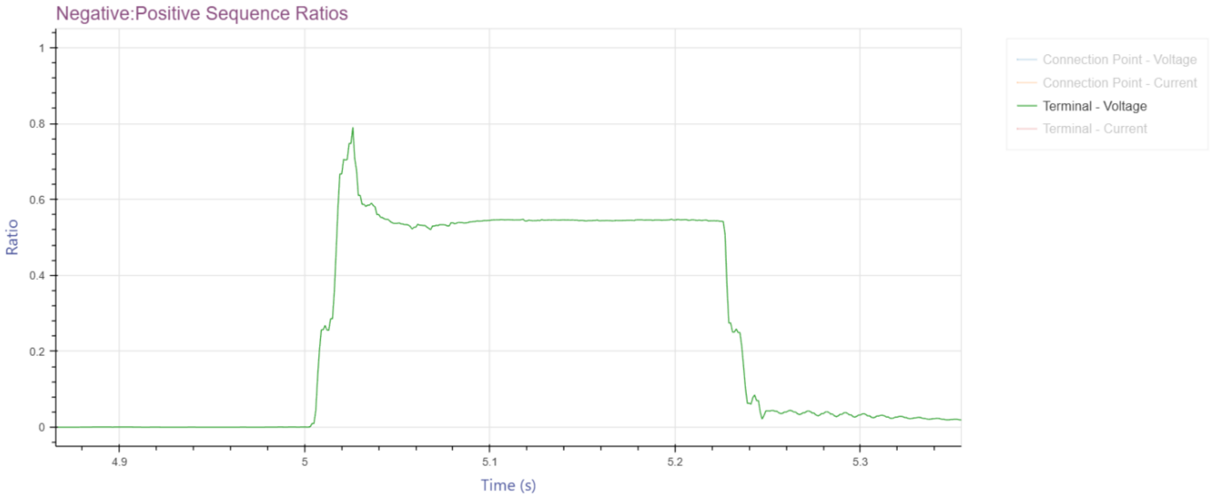


Figure 55 Site-specific GFM BESS: voltage unbalance factor

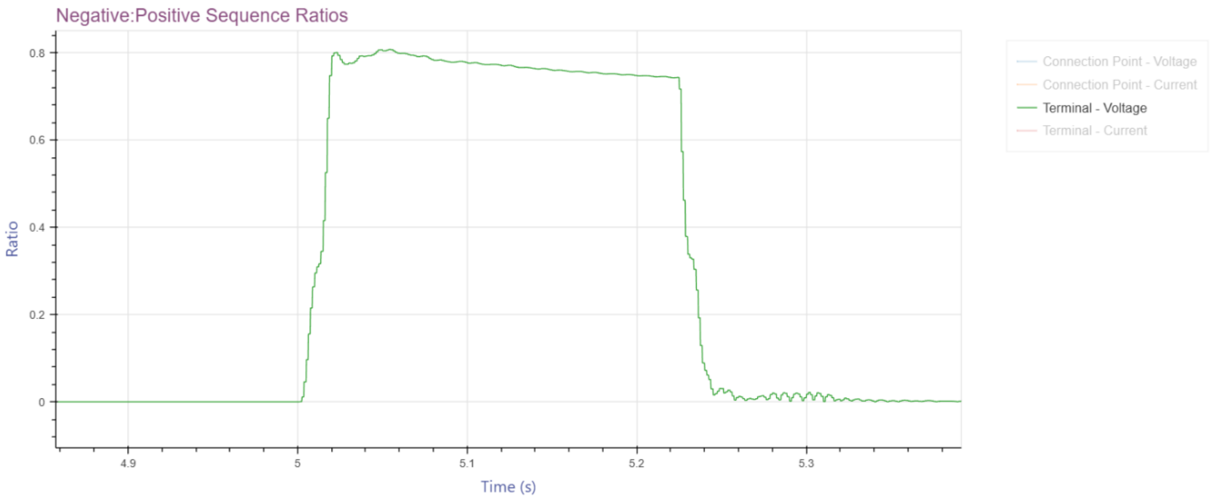


Figure 56 Type 4 WF: Voltage unbalance factor

Table 14 Voltage unbalance factor

Sr No	Technology	Voltage unbalance factor
	Synchronous machine	0.42, stable [current ratio I2/I1 : 0.7 slowly red to 0.6]
1	Generic GFL BESS without NS control	0.78, slowly reducing and stable around 0.69
2	Generic GFL BESS with NS control	0.72, slowly reducing and stable around 0.62 [Current ratio: stable around 0.39]
3	Site-specific GFL BESS without NS control	0.45, stable [Current ratio: 0.06 and quickly reduced to 0.03]
4	Site-specific GFL BESS with NS control	0.28, stable [Current ratio: stable around 0.57]
5	Type 3 wind farm	0.86, stable [Current ratio: 0.85 and stable]
6	**Type 4 wind farm**	**0.79, slowing reducing and stable around 0.75**

Sr No	Technology	Voltage unbalance factor
		[current ratio: 0.13, slowly increasing and stable at 0.169]
	Type 4 wind farm with NS control	0.68, stable [current ratio: stable around 0.25]
7	Generic GFM BESS without NS control	0.79, stable [current ratio: 0.05 and stable]
8	Generic GFM BESS with NS control	0.91, stable [current ratio: 0.38 stable]
9	Site-specific GFM BESS	0.55, stable [current ratio: 0.6 stable]
10	Generic GFM Solar (droop)	0.52, stable
	Generic GFM Solar (VSM)	0.52, stable

Summary

Table 15 provides a summary of the results based on the following ‘guiding principles’.

- During a fault, negative-sequence current should lead the negative-sequence voltage by approximately 90° (± 10° tolerance)[7].
- The direction of negative-sequence current should be from the IBR towards the grid during the fault.
- Effective negative-sequence impedance should be close to effective positive-sequence impedance.

The summary results presented in Table 15 are derived from existing models utilising their native control systems. The comparison is intended solely to illustrate the relative performance of each technology and does not imply endorsement or preference for any particular technology.

Note: Green circle means acceptable, Orange circle means less than acceptable and Red circle means not acceptable performance.

Table 15 Comparison of various IBR technologies and their response during the fault

Sr No	Technology	Phasor relationship	Current injection	Effective negative and positive-sequence impedance
1	Synchronous machine	🟢	🟢	🟢
2	Generic GFL BESS without NS control	🔴	🔴	🔴
3	Generic GFL BESS with NS control	🔴	🟢	🟠
4	Site-specific GFL BESS without NS control	🔴	🟢	🔴
5	Site-specific GFL BESS with NS control	🟢	🟢	🟢
6	Type 3 wind farm	🔴	🟢	🔴
7	Type 4 wind farm	🔴	🔴	🔴
8	Type 4 wind farm with NS control	🟢	🟢	🔴
9	Generic GFM BESS without NS control	🔴	🟢	🔴
10	Generic GFM BESS with NS control	🔴	🟢	🟢

[7] Type 3 wind generator might need larger tolerance band, but it has not been factored in this analysis.

Sr No	Technology	Phasor relationship	Current injection	Effective negative and positive-sequence impedance
11	Site-specific GFM BESS			
12	Generic GFM Solar (droop)			
13	Generic GFM Solar (VSM)			

3.2 Network Studies

3.2.1 Study set up

Figure 57 shows a representative network that was used for the network level assessment. It comprises of two Hubs which consists of generation from synchronous machine, wind farm and battery. These generation technologies have been considered as example technologies to representation generation mix that is likely to be present in a typical power system. The fault current behaviour during various scenarios (as listed in Table 16) is observed at the sending of the 500 kV line as shown in Figure 57.

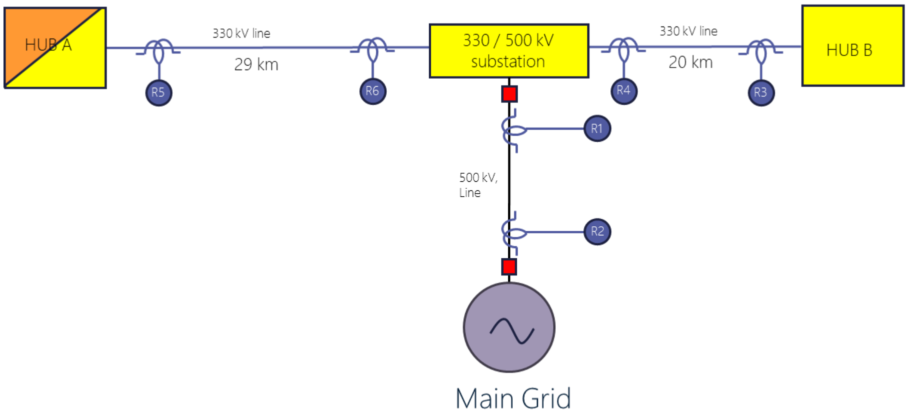


Figure 57 Representative network configuration

Table 16 List of scenarios

Scenario	Hub A				Hub B			
	Synchronous (MW)	GFL BESS (MW)	WF (MW)	Negative-seq control	Synchronous (MW)	GFL BESS (MW)	WF (MW)	Negative-seq control
B01	600	0	0	NA	600	0	0	NA
B02	400	0	200	Enable	400	0	200	Enabled
B02a	400	0	200	Disable	400	0	200	Disable
B03	400	200	0	Enable	400	200	0	Enabled
B03a	400	200	0	Disable	400	200	0	Disable
B04	200	0	400	Enable	200	0	400	Enable
B04a	200	0	400	Disable	200	0	400	Disable
B05	200	400	0	Enable	200	400	0	Enable
B05a	200	400	0	Disable	200	400	0	Disable
B06	60	400	200	Enable	60	400	200	Enable
B07	0	500*	200	Enable	0	500*	200	Enable

*** 100 MW GFM BESS and 400 MW GFL BESS**

3.2.2 Results and discussion

This section discusses the fault current behaviour at the sending end of the 500 kV transmission line. The focus has been on the phasor relationship between negative-sequence current and negative-sequence voltage at the point of interest under various scenarios.

During the SMIB assessment it was observed that IBR with negative-sequence control helps to keep the phasor relationship between negative-sequence voltage and negative-sequence current closer to 90° leading. At the same time, appropriately tuned control can priorities magnitude of the negative-sequence current.

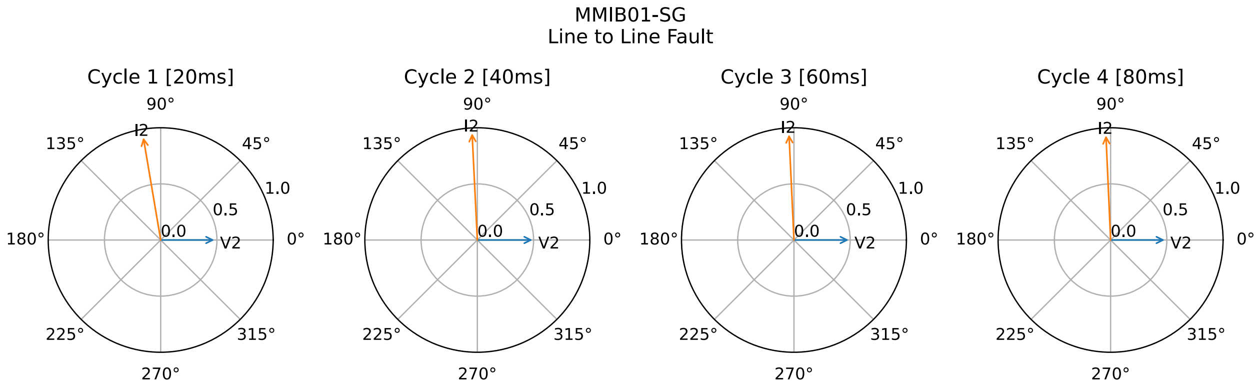


Figure 58 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B01 (reference)

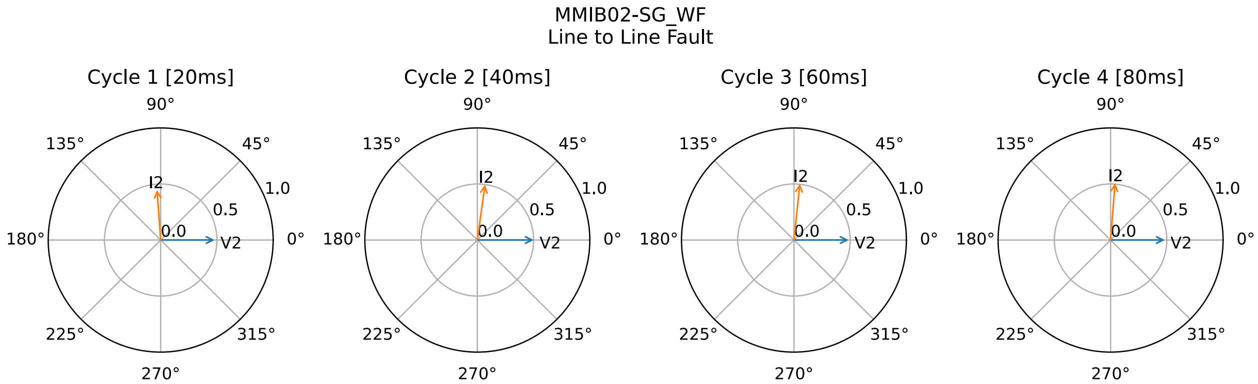


Figure 59 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B02

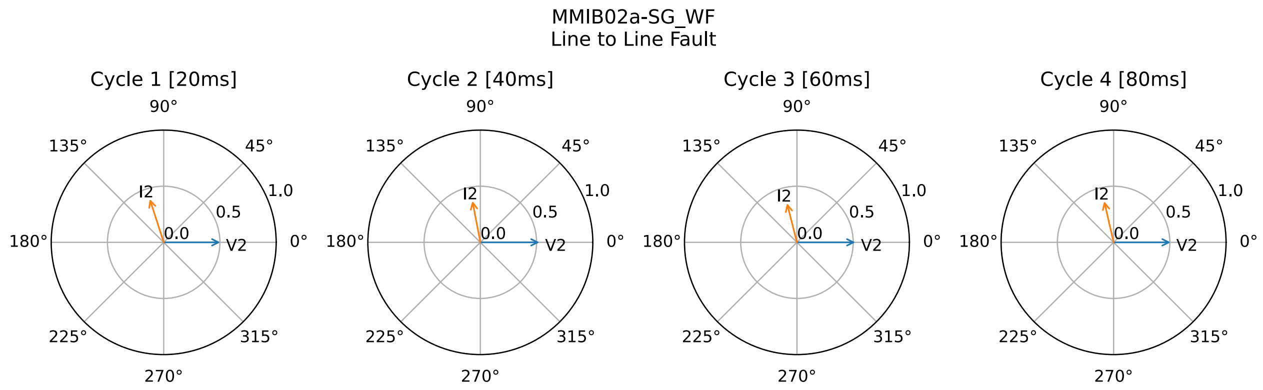


Figure 60 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B02a

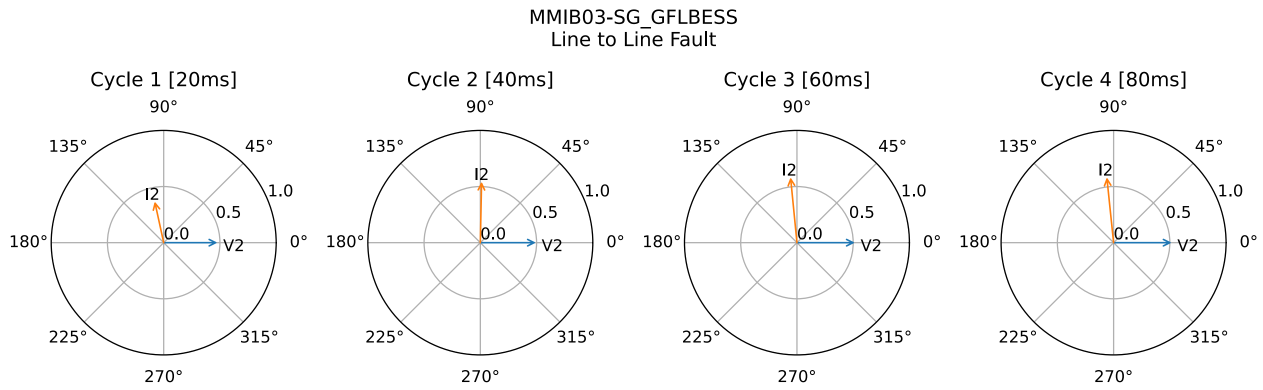


Figure 61 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B03

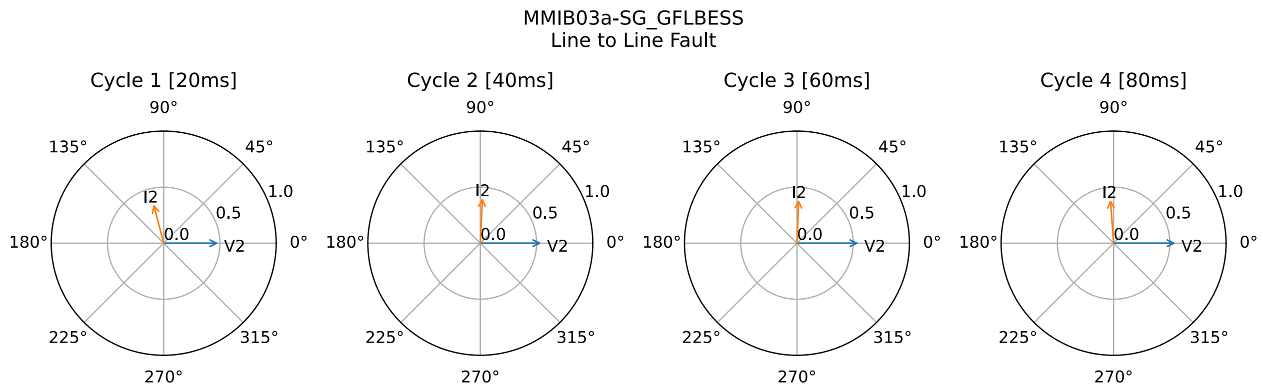


Figure 62 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B03a

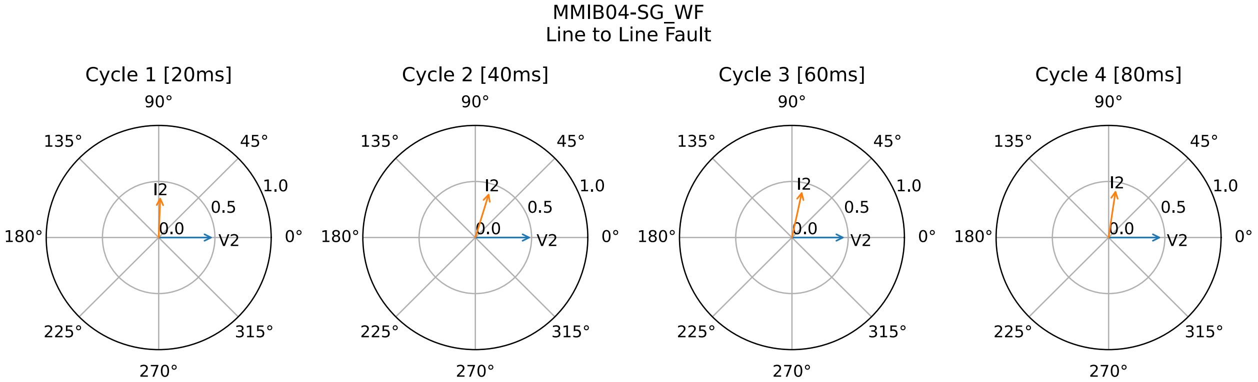


Figure 63 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B04

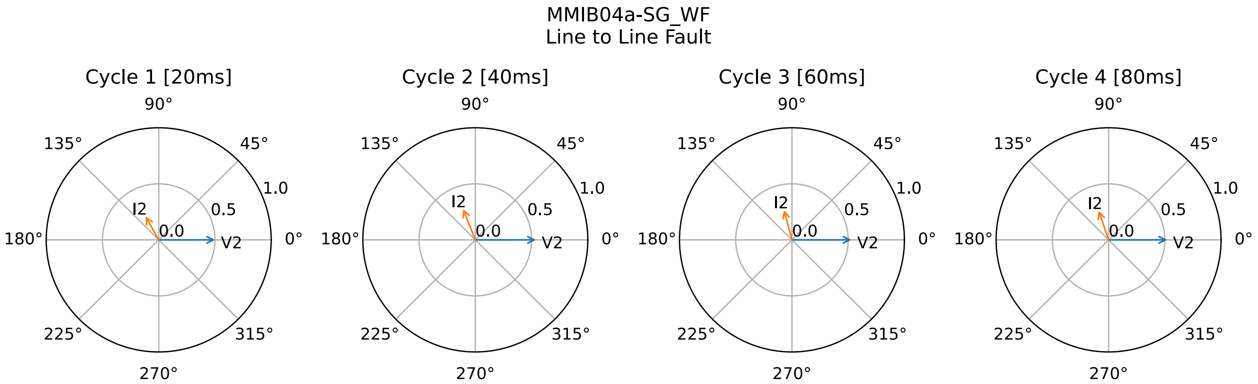


Figure 64 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B04a

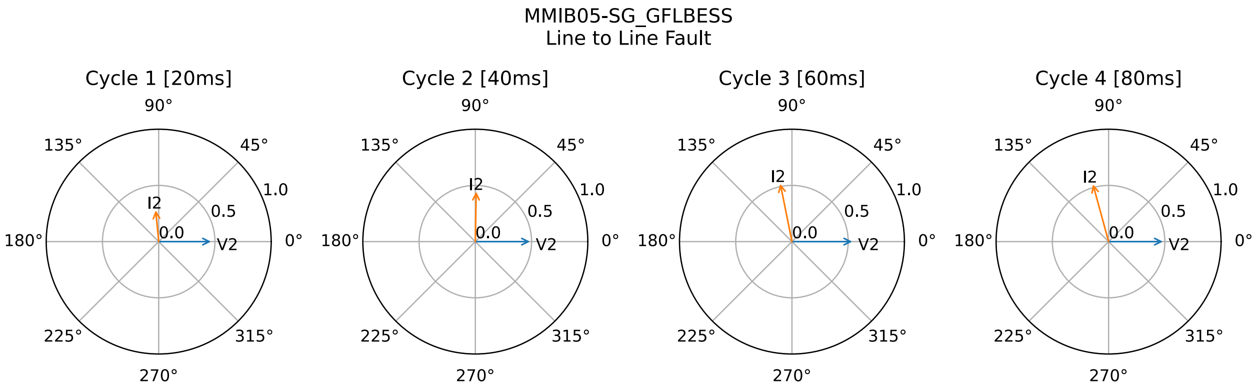


Figure 65 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B05

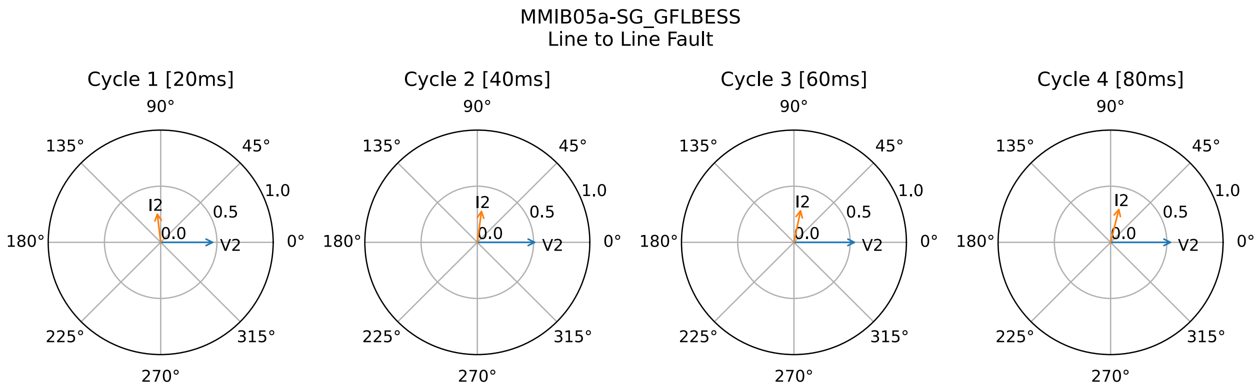


Figure 66 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B05a

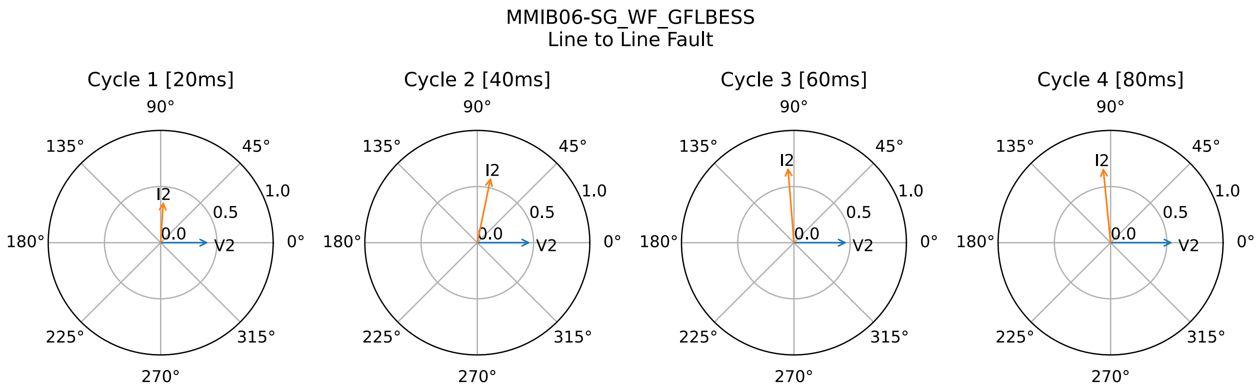


Figure 67 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B06

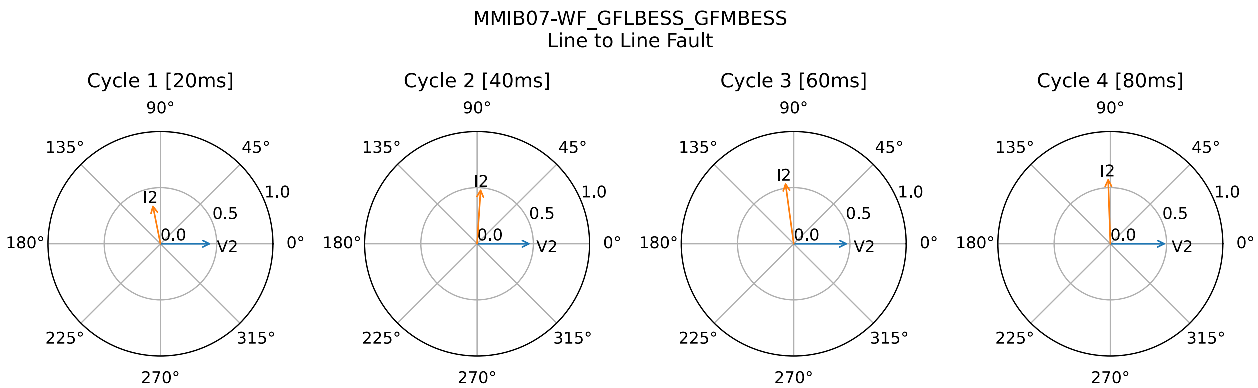


Figure 68 Relationship (magnitude and angle) between V_2 and I_2 during L-L fault for Scenario B06

3.3 Summary of power system studies

Following is an outline of key observations based on the network studies carried out, which included a mix of different generation technologies. The results focused on the overall negative-sequence response during the fault. The summary results presented are derived from existing models utilising their native control systems. The comparison is intended solely to illustrate the relative performance of each technology and does not imply endorsement or preference for any particular technology

- In a scenario, with higher share of synchronous generation, desired phasor relationship between negative-sequence voltage and current is observed at the fault location.
- When the generation from IBR increases, the phasor relationship between negative-sequence voltage and current starts to deviate and depends on the amount of IBR and its control tuning.
  - As an example, during a scenario where a large amount of WF generation displaces synchronous generation (i.e. scenario B04a), the magnitude of negative-sequence current reduces, as well as it impacts the phasor relationship. In this scenario (i.e., scenario B04a), WF with negative-sequence control enabled helps achieve better phasor stability than WF with negative-sequence control disabled. This finding aligns with the SMIB assessment, which suggested that inclusion of negative-sequence control will help to stabilise the negative-sequence phasor and achieve 90°leading phasor relationship.
- With negative-sequence control enabled, the amount of negative-sequence control can be prioritised, resulting in a higher magnitude of the negative-sequence current.
  - As an example, during a scenario where a large amount of BESS generation displaces synchronous generation (i.e. scenario B05 and B05a), the BESS with negative-sequence control enabled provides a higher amount of negative-sequence current compared to the BESS without negative-sequence control.

Table 17 summarises high-level observations made based on the network studies.

Table 17 Observed outcome based on network studies

System Condition	Observed Outcome
High synchronous machine share	Stable 90° phasor relationship between V_2 and I_2, high negative-sequence current magnitude
High IBR share (no negative-sequence control)	Reduced I_2, magnitude, poor phasor angle, could degrade protection visibility
High IBR share (with negative-sequence control)	Improved phasor angle (~90°), higher I_2 magnitude
Weak grids	The effects above become more significant

Part II Development of technical standards for GFM inverters with respect to impact on protection

4 Background and Introduction

4.1 Objective and Scope

The objective of Task 2 (Part II) is to assess how the changing fault behaviour of inverter-based resources (IBRs), and grid-forming (GFM) inverters in particular, affects the performance of conventional power system protection, and to develop technical requirements that preserve protection dependability as IBR penetration increases. Traditional protection was designed around synchronous generators that supply high-magnitude, predominantly inductive fault currents with stable, predictable sequence-component relationships. IBR fault current, by contrast, is limited in magnitude, control-dependent, and variable in phase, particularly for negative-sequence quantities. Part II examines the resulting risks of protection mis-operation and translates the findings into draft technical requirements and verification methods.

Part II is intended to bridge inverter control behaviour and protection practice. It identifies the protection functions most exposed to IBR fault behaviour, demonstrates the failure mechanisms through literature and simulation, and consolidates the evidence into requirements that can be communicated to inverter OEMs, network service providers, and standards bodies. Negative-sequence behaviour is treated as protection-critical rather than as an optional control feature, addressing a gap in existing Australian arrangements (for example, the NER), which do not explicitly define negative-sequence current magnitude, phase angle, or current-limiting behaviour.

The displacement of synchronous generators (SGs) by inverter-based resources (IBRs) fundamentally alters the fault current characteristics upon which power system protection has been designed for decades. Traditional protective relays rely on high-magnitude, predominantly inductive short-circuit currents with well-defined sequence-component relationships. IBRs, by contrast, produce fault currents that are low in magnitude (typically limited to 1.1–1.2 pu), and whose sequence-component composition depends entirely on the inverter control strategy [18], [19]. There are three critical protection functions affected by IBR integration: directional relaying, faulted phase identification, and the role of negative-sequence current control. These topics are directly relevant to protection compatibility assessment under high-IBR penetration scenarios being studied in the Australian NEM context [20].

4.2 Protection compatibility assessment

There are key differences between IBRs and Synchronous generators in terms of how they respond to power system faults.

- Fault current magnitude and shape: Synchronous generators naturally supply high and sustained fault currents governed by physical machine parameters. In contrast, IBRs can only supply current up to the converter’s current limits. Their control systems intentionally constrain output to protect semiconductor devices from thermal stress. Therefore, IBR fault current magnitude is typically close to or slightly above rated current, rather than multiples of rated current as in SGs. For IBR, a momentary increase in the current (above its thermal rating) can be achieved typically for 0.5–1.5 cycles before being limited by fast converter control response. Due to converter switching actions, the fault current waveform shape may contain a lot of harmonic components which can limit the effectiveness of protection elements that rely on well-behaved symmetrical components.

- Negative-sequence and unbalanced fault behaviour: Negative-sequence currents are essential for directional and phase-comparison relays. SGs inject robust, predictable negative-sequence currents during unbalanced faults. IBRs, however may inject very low or nearly zero negative-sequence current, depending on converter control philosophy. With each OEM having specific negative-sequence profiles, the complexities of protection coordination and validation increases. Potentially, IBR can generate sequence component transients that vary widely during initial cycles, undermining algorithms that depend on stable pre-fault and fault quantities.

Impact of IBRs on power system protection is highly dependent on the protection algorithm used by the relay to detect and isolate the fault. IBRs producing low and variable fault currents can cause under-reaching or over-reaching of distance relay, impedance trajectory distortions and failure in detecting high-impedance faults. In relation to directional protection, directional elements depend on stable relationships between sequence voltages and currents. With IBRs this angle relationships may be time-varying and very low negative-sequence current may hinder directional discrimination.

4.2.1 Impact on directional relaying

Directional elements are fundamental to pilot protection schemes (permissive overreach, directional comparison blocking) and to ground distance supervision. Two principal directional methods are affected: negative-sequence-based (67Q) and zero-sequence-based (67N) directional elements.

The IEEE PES Power System Relaying and Control Committee (PSRC) Working Group C32 report [18] documented field events where 67Q elements failed to correctly determine fault direction on lines terminated by IBRs. The root cause is twofold: (i) IBRs operating under coupled-sequence control (CSC) suppress negative-sequence current, eliminating the operating quantity required by the directional element; and (ii) even where negative-sequence current is present, its phase angle relationship to negative-sequence voltage is non-standard and varies with the control implementation, proportional gain settings, and inverter current limits [21] [22] [23]. The 67Q elements can mal-operate for unbalanced faults when IBRs suppress negative-sequence current, and directional comparison blocking (DCB) and directional comparison unblocking (DCUB) schemes were found to have been compromised because the IBR-side relay communicated incorrect directional signals [22]. The PNNL review confirmed these findings and further noted that under decoupled-sequence control (DSC), the negative-sequence current phase angle is determined by the control gain parameter k, which varies across manufacturers and grid codes [24]. A similar mis-operation is noted BC Hydro's system, showing that even STATCOM devices contributed fault currents with non-standard sequence-component relationships that interfered with 67Q elements [25].

4.2.2 Impact on faulted phase identification

Faulted phase identification (FID) algorithms, also termed phase selectors, are critical for single-pole tripping and for supervising distance elements. Most commercial FID algorithms rely on the angular relationship between negative-sequence and zero-sequence current phasors.

The EPRI technical report on negative-sequence-based protection demonstrated that under full-scale converter (FSC) wind turbine generators, the FID scheme misidentified the faulted phase because the negative-sequence current phasor angle was determined by the inverter control rather than by the fault location and type [22]. Specifically, the angular difference between I_2 and I_0 no longer fell within the expected sector for the actual faulted phase, causing the algorithm to declare an incorrect phase.

Six phase-selection algorithms not previously tested in the IBR context, considering both full-converter and DFIG topologies is evaluated in [26] . It was found that incremental-phasor-based and current-angle-based phase selectors were both vulnerable to mis-operation, though to differing degrees depending on the IBR type and control mode. The IEEE 2800-2022 requirements for negative-sequence current injection improved FID algorithm performance, though not universally across all fault types and locations [27].

The literature consistently identifies three interrelated protection vulnerabilities: (i) failure of negative-sequence directional elements due to suppressed or phase-shifted I_2 from IBRs; (ii) misidentification of faulted phases by FID algorithms that rely on I_2/I_0 angular relationships; and (iii) the critical dependence of both functions on the IBR negative-sequence control strategy and grid code requirements. Section 5.1 uses power system simulations to further expand this issue through simulations.

4.3 Impact of single pole auto-reclose on grid-forming inverters

Single pole auto-reclose (SPAR) is a standard protection practice on high-voltage transmission lines, where the faulted phase is opened and reclosed after a dead time (typically 0.5–1.5 seconds) to clear transient single-phase-to-ground faults. During the dead time, the transmission line operates in a single-pole-open (SPO) condition, creating a sustained voltage unbalance that persists far longer than a typical fault. As the Australian NEM transitions toward high penetrations of grid-forming (GFM) inverter-based resources (IBRs), the impact of SPAR events on GFM inverter stability, DC-link voltage, and negative-sequence voltage oscillations requires careful investigation.

This literature review addresses Activity 4 of AR-PST Topic 1, Stage 5: assessing GFM stability during delayed and unbalanced reclose conditions. A targeted search revealed that the specific intersection of SPAR with GFM inverter stability is a significant research gap. Very few publications address this exact scenario directly. However, a substantial body of work on closely related topics (unbalanced fault ride-through, negative-sequence control, DC-link dynamics under unbalance, and auto-reclose protection in IBR-rich systems) provides the technical foundation for this review.

4.3.1 SPAR and the Single-Pole-Open condition

During an SPO condition, the un-faulted phases remain energised while the faulted phase is de-energised. This creates sustained voltage unbalance at nearby buses, with negative-sequence voltage magnitudes that can reach 30–50% of the positive-sequence voltage depending on system impedance and topology [28] [29] . Unlike a typical fault (cleared in 50–150 ms), an SPO condition can persist for 0.5–1.5 seconds or longer with delayed reclose schemes, exposing connected equipment to prolonged unbalanced conditions.

The IEEE PSRC WG C32 report identifies single-phase trip and reclose as a specific concern for IBR-rich systems, noting that IBR fault current characteristics (limited magnitude, control-dependent negative-sequence current) can affect protection schemes that rely on sequence components for fault type identification. Incorrect fault type identification can lead to maloperation of single-pole tripping logic, potentially preventing successful SPAR sequences [18] [30].

4.3.2 GFM inverter behaviour under unbalanced conditions

Negative-Sequence Current and Voltage Response

GFM inverters, by maintaining a balanced internal voltage source, naturally produce unbalanced output currents when exposed to unbalanced grid voltages. This differs from many GFL inverters, which may suppress negative-sequence current [22], [24]. AEMO voluntary specification [1] expects GFM inverters to maintain a balanced internal voltage during asymmetrical disturbances, inherently producing negative-sequence current proportional to the negative-sequence voltage and the inverter's negative-sequence impedance.

To meet IEEE 2800-2022 negative-sequence current requirements, control strategies for GFM inverters can be developed for coordinating positive and negative-sequence current within the total current capacity however, it would require careful current management [14]. The PNNL report [24] confirms that negative-sequence current generation by IBRs during unbalanced conditions lacks consistency across different IBR types and manufacturers.

The most comprehensive review of current limiting under asymmetrical faults for GFM inverters is presented in [31]. GFM inverters are expected to act as a sink for unbalances per ENTSO-E, providing low negative-sequence impedance. The review classifies strategies that support independent positive and negative-sequence control, including priority-based current saturation and modified threshold virtual impedance approaches. A key finding is that the maximum negative-sequence current capability of GFM inverters is limited to approximately 57.7% of rated current due to per-phase current constraints [31].

Stability During Prolonged Unbalance

The extended duration of an SPO condition poses a distinct stability challenge. During a balanced fault, the GFM power synchronisation loop (PSL) accelerates due to the power imbalance, but this is short-lived (50–150 ms). During an SPO condition lasting 0.5–1.5 seconds, the sustained positive-sequence voltage reduction and negative-sequence voltage presence create a prolonged power imbalance that may cause integrator windup in the PSL [31] [32].

An extended power synchronisation method for GFM converters handling both balanced and unbalanced grid conditions with embedded current limiting and re-synchronisation functions is presented in [33]. The control naturally switches to current control mode when limits are exceeded during asymmetrical faults, with a re-synchronisation aid function to limit frequency variation during extended disturbances.

The NREL report on overcurrent limiting in GFM inverters notes that indirect current-limiting methods such as virtual impedance can retain voltage-source behaviour and support voltage during both balanced and unbalanced faults, which is advantageous during an SPO condition where the inverter must continue operating rather than ride through a short-duration event [34].

DC-Link Voltage Dynamics During Unbalanced Operation

The DC-link voltage of a voltage source inverter is directly affected by power oscillations from unbalanced AC-side conditions. During an SPO condition, the negative-sequence voltage produces a double-fundamental-frequency (100 Hz) oscillation in the instantaneous power, which propagates to the DC-link voltage [35] [36].

This unbalanced grid conditions produce power oscillations propagating to the DC-link, causing double-fundamental-frequency voltage oscillations that affect capacitor aging and converter control performance. Even modest unbalance factors (2.5%) can halve DC-link capacitor lifetime if the unbalanced condition persists, due to thermal stress from additional low-frequency ripple current. This is particularly relevant to SPO conditions, which persist far longer than typical faults [37].

For GFM inverters with PV or limited energy storage, the reduced active power export during a voltage sag (including the partial reduction from SPO) can cause a DC-side power surplus. If the DC source continues injecting power while AC-side export is constrained, the DC-link voltage rises. DC-link overvoltage protection (typically at 110–120% of nominal) may trip the inverter during the SPO dead time.

4.4 Impact of grid-forming inverters on loss of synchronism

Power swing dynamics in systems containing GFM inverters differ fundamentally from those in traditional SG-dominated systems. In conventional systems, power swings arise from electromechanical oscillations of physical rotor angles. In GFM systems, the swing behaviour is governed by control dynamics rather than physical inertia, with the internal reference angle of the power synchronisation loop (PSL) replacing the rotor angle as the key state variable.

Power swing behaviour is also present in GFM systems, demonstrated inertial GFM controllers (e.g. VSM) that can exhibit loss of synchronisation characterised by divergence of the output angle in the active power control loop [38]. Non-inertial GFM controllers (e.g. droop) can re-synchronise after faults but may experience significant power oscillations driven by control dynamics. These behaviours differ from SG systems where power swings are driven by physical angle deviations among rotating masses.

Power oscillation damping (POD) controllers for GFM converters, demonstrating that GFM converters inherently exhibit angle oscillations following grid disturbances due to synchronous generator emulation [39]. For damping of inter-area oscillations in a two-area system, active power-based POD (POD-P) is more effective than reactive power-based POD (POD-Q) but requires energy storage at the DC bus.

A key finding across the literature is that legacy impedance-based power swing detection (e.g. dual-blinder schemes for power swing blocking and out-of-step tripping) may not perform reliably in systems with significant GFM penetration [38], [40]. The impedance trajectory during GFM-driven swings does not follow classical circle trajectories, potentially causing maloperation of protection schemes designed for SG-dominated systems.

4.4.1 Loss of Synchronism Mechanisms in GFM-VSM

The key mechanism for loss of synchronism in GFM inverters is tied to current limiting during faults. Unlike synchronous generators, which can deliver fault currents of 5–10 times rated current, GFM inverters are typically limited to 1.2–2.0 times rated current due to power electronic thermal constraints [41]. When a GFM inverter enters current-limited operation, the power synchronisation loop can wind up, causing the internal reference angle to diverge and resulting in total loss of synchronism [42].

Current Limiting as a key cause

Current limiting strategies for GFM inverters during low voltage ride-through (LVRT) is comprehensively discussed in [31]. It classifies strategies into voltage-based approaches (e.g. threshold virtual impedance) and current-based approaches (e.g. current saturation algorithms), evaluating their performance against three criteria: transient current limitation, fault current management, and transient synchronisation stability. A critical finding is the inherent trade-off between current limitation and synchronisation stability: strategies that effectively limit current often degrade synchronisation performance.

A transient stability enhancement method based on fictitious power injection, which counteracts integrator windup in the primary controller during current-limited operation is proposed in [43]. The NREL report demonstrates that both VSM and dVOC primary controllers can lose synchronism during voltage sags without supplementary synchronisation terms, and proposes an enhanced large-signal stability method that preserves synchronisation even under severe disturbances [42].

4.4.2 Key drivers for loss of synchronism

The following parameters and conditions are identified as the primary drivers for loss of synchronism in systems with GFM-VSM inverters:

- Virtual inertia constant (H): Higher inertia slows the angle response but also increases the energy accumulated during faults, potentially exceeding the available deceleration area. The inertia must be co-designed with damping to avoid instability.
- Virtual damping coefficient (D): Higher damping improves transient stability margins by dissipating energy during the swing, but also serves as the primary frequency controller, creating a design trade-off between transient stability and frequency droop performance.
- Current limit magnitude and strategy: The current limit (typically 1.2–2.0 pu) directly determines the maximum power deliverable during a fault, which defines the deceleration area in the P–δ curve. The choice of limiting strategy (virtual impedance, current saturation) fundamentally affects whether synchronisation is maintained.
- Fault severity and duration: Deeper voltage sags and longer fault durations increase the acceleration area, reducing the critical clearing angle. Phase jumps as small as 10° can push the inverter angle beyond the critical clearing angle.

- Grid strength (SCR) and X/R ratio: Lower SCR increases the electrical distance and reduces the maximum transferable power, narrowing the stability margin. The X/R ratio affects coupling between active and reactive power loops.
- Pre-fault operating point: Higher pre-fault power transfer increases the initial angle, reducing the available deceleration area and lowering the critical clearing angle.
- Reactive power/voltage control interaction: The voltage controller dynamics and reactive power droop settings interact with the active power synchronisation loop during current-limited operation, affecting the effective P–δ characteristic and stability boundary.

5 Simulation Studies Investigating Influence of GFM IBRs on Protection

The objective of the studies presented in this section is to evaluate the influence that modern IBR technologies, including both grid-following and grid-forming configurations, can have on distance protection relays applied for the purpose of transmission line protection. Distance relays, which operate on the principle of measuring apparent impedance at the relay location to determine fault proximity, were designed under the assumption of synchronous machine dominated systems. These machines exhibit well understood fault current characteristics. Whereas the IBRs exhibit fundamentally different fault response behaviours governed by their power electronic controls, current limiting strategies, and grid-forming or grid-following operating modes. Therefore, it has become a challenge for distance relays to achieve their expected performances the underlying assumptions embedded in conventional distance protection logic.

To provide a thorough evaluation, the assessment examined several key functional elements of distance protection schemes. Each scheme was analysed with respect to how IBR fault contributions impact the scheme. The specific components of distance protection schemes assessed as part of this study include the following:

- Reach element: Reach elements estimate the distance to the fault to determine the correct zone (Zone1, Zone2, etc.)
- Directional element: Directional element determines the directionality of the fault (forward or reverse)
- Faulted phase identification element: Faulted phase identification elements determine the faulted phase and crucial during single phase fault conditions to determine the correct phase to be tripped.

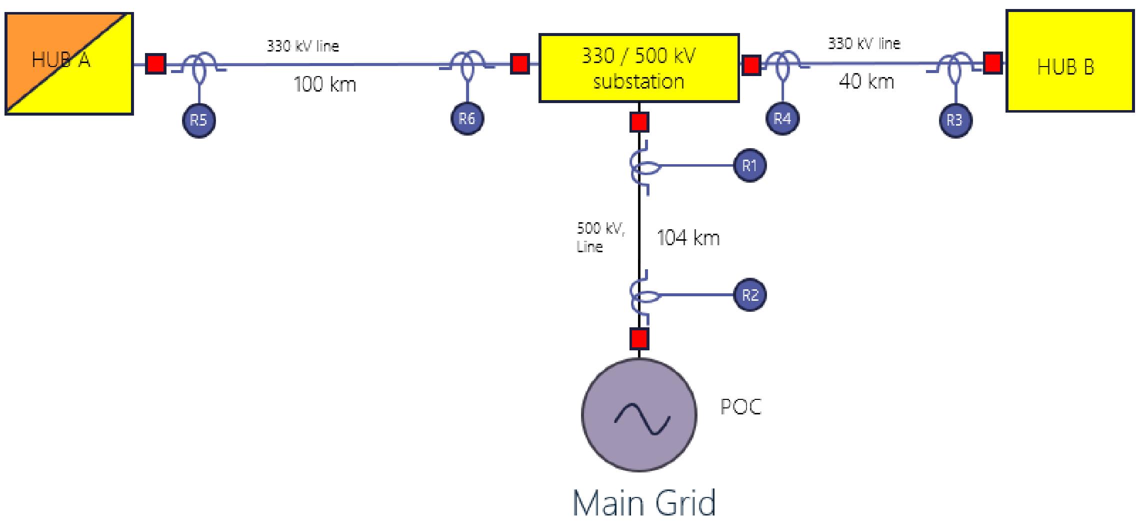


Figure 69 Multi-machine system

Figure 69 shows multi-machine system that was used for this analysis.

- Hub A and Hub B are considered as renewable energy zone or part of the renewable energy zone.
- Main grid represents rest of the network where renewable energy zone is connected.

To demonstrate the inter-relationship between IBR and protection adequacy representative IBR models were considered at Hub A and Hub B. Also, during the work the generation technology at Hub B was not changed while various sensitivities for the generation type at Hub A were considered.

5.1 List of scenarios and contingencies

To evaluate the performance of the distance protection relays, the test system shown in Figure 69 was simulated in the PSCAD/EMTDC simulation environment.

Table 18 shows the generation/dispatch combinations at Hub-A. Note that negative sequence control was turned off for the scenarios with BESS units and a wind farm at Hub A. Generation at Hub-B was kept unchanged with a GFL BESS. Both GFM and GFL BESS were 1.1 MVA inverters with the exact same electrical components – only controls differed. Virtual synchronous machine (VSM) algorithm was used for the GFM BESS. Current limiting was a hard limit.

Table 18 Study scenarios: Generation technology at Hub A

Scenario	Wind (Type-4)[8]	GFL BESS	GFM BESS	Synchronous Generators
1	In-service	Out of service	Out of service	Out of service
2	Out of service	In-service	Out of service	Out of service
3	Out of service	Out of service	In-service	Out of service
4	Out of service	Out of service	Out of service	In-service

Different types of faults (single phase to ground faults, phase-to-phase faults, phase-to-phase-ground faults and three-phase faults) were simulated at different locations along the line as depicted in Figure 70. Additional sensitivity scenarios were evaluated with negative sequence control enabled.

[8] Grid-following wind farm

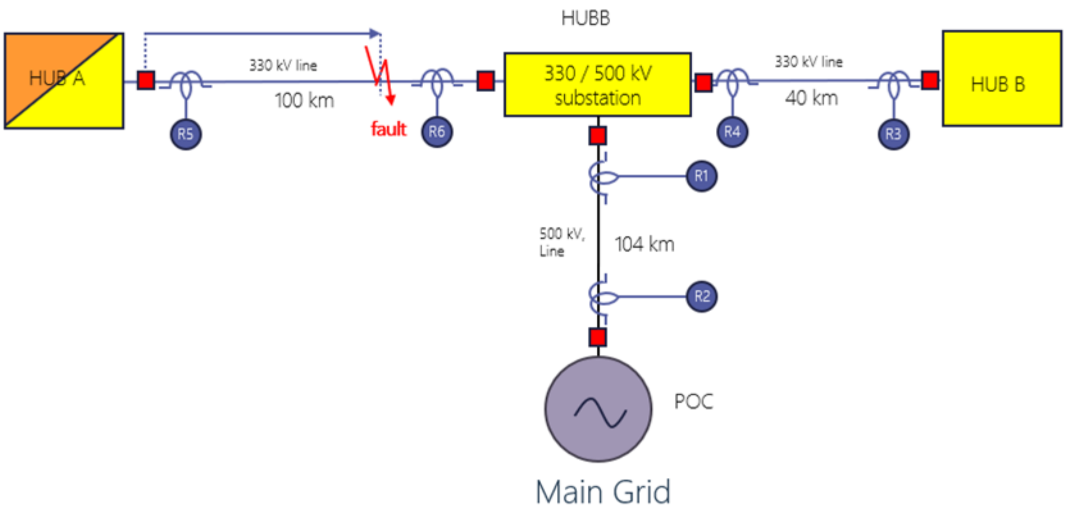


Figure 70 Multi-machine system with fault location

The protection library available in PSCAD/EMTDC was used to simulate the distance relays. The Zone-1 and Zone-2 reach settings were set to 80% and 120% respectively in the forward direction. The directional element was set to operate based on the following priorities.

- Negative sequence
- Zero sequence
- Positive sequence

The response of the relay (R5) connected at Hub-A protecting the 330 kV transmission line was analysed in detail under various generation/dispatch conditions/scenarios. The transmission line (100km line form Hub-A to 330/500kV hub) parameters and R5 relay settings are summarized in Table 19.

Table 19 Transmission line model parameters and R5 relay settings

Item	Value
Line Length	100 km
Positive sequence impedance	31.05 <82.7^0 Ohms
Zero sequence impedance	98.49 <70.1^0 Ohms
CT ratio	1600:1
PT ratio	1000:1

5.2 Results and discussion

Performance of the relay was evaluated under different fault types and locations, and results are presented for boundary fault conditions (75% and 85% fault locations) focusing on unbalanced faults.

5.2.1 Scenario 1

Figure 71 and Figure 72 show the response of the directional elements for a single-phase to ground fault and phase-to-phase fault for the scenario with a wind farm at Hub A with negative sequence control disabled. Faults were introduced 10.0 seconds into these simulations. While the faults persisted, the directional elements went into dropout, signalling that the fault originated from the reverse direction. Meanwhile, the reach elements and faulted phase detection elements performed as expected for the simulated fault conditions[9].

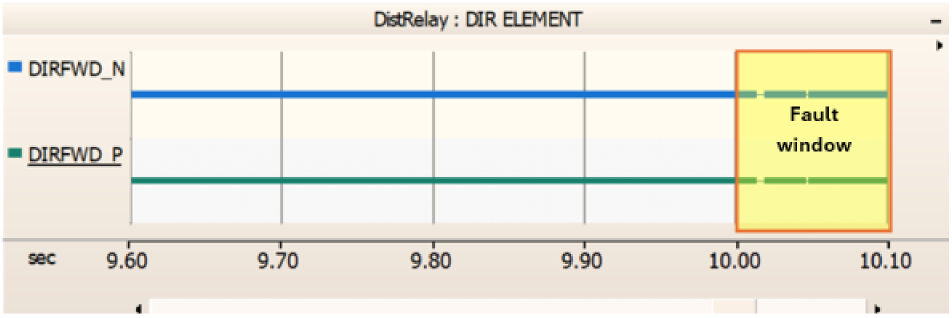


Figure 71 Directional element during phase-to-ground fault at 85%

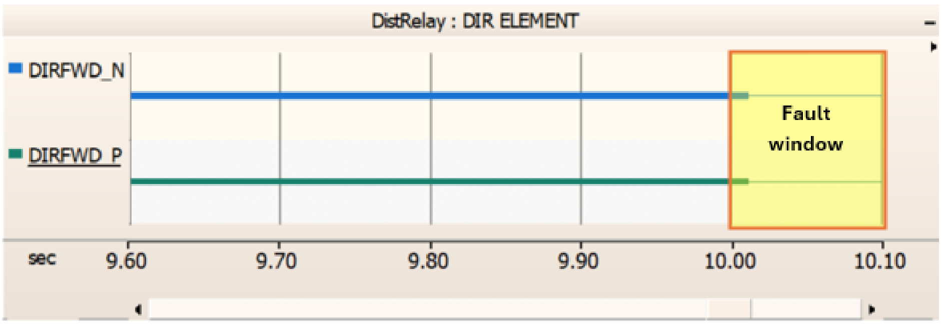


Figure 72 Directional element during phase-to-phase fault at 85%

Table 20 summarizes the results for other types of unbalanced faults considered in the study. The performance issues were observed in the directional element.

Table 20 Results for Type 4 WF scenario without negative sequence control

Fault Location	Type	Reach	Directional Element	Faulted Phase Identification
75%	AG	Correct operation	Delayed operation with chattering	Correct operation
	ABG	Correct operation	Failure to operate	Correct operation
	AB	Correct operation	Failure to operate	Correct operation
85%	AG	Correct operation	Delayed operation with chattering	Correct operation
	ABG	Correct operation	Failure to operate	Correct operation
	AB	Correct operation	Failure to operate	Correct operation

[9] A desirable operation would either have a high status (or solid line) or low status (no line) during the fault duration and dependent on the fault direction. A change between theses statuses indicate un-desired operation.

5.2.2 Scenario-2

Figure 73 and Figure 74 show the response of the directional element during a phase-to-phase fault and a single phase to ground fault simulated at 85% on the transmission line for the scenario with GFL BESS at Hub A without Negative sequence control. The findings show that the directional element operated unexpectedly throughout the fault period.

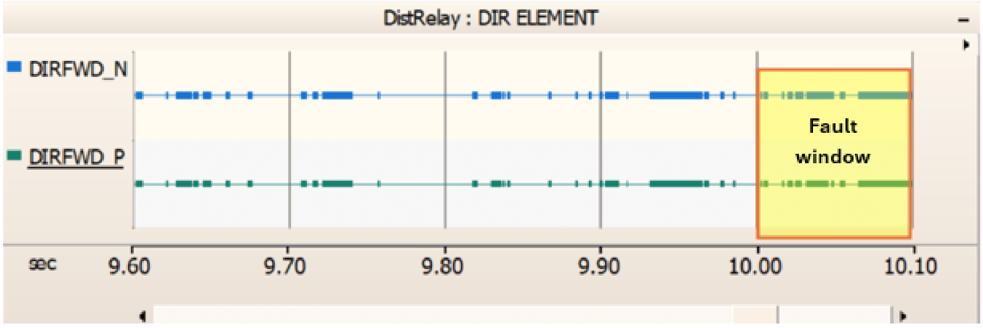


Figure 73 Directional element during phase-to-ground fault at 85% *

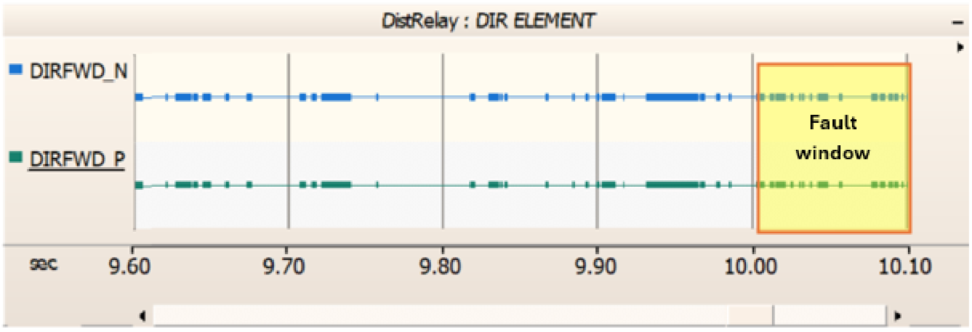


Figure 74 Directional element during phase-to-phase fault at 85% *

*Note that any fluctuations observed during pre-fault conditions are observed due to measurement noise and can be disregarded.

Table 21 shows the summary results for GFL BESS without negative sequence control.

Table 21 Results for GFL BESS without negative sequence Control

Fault Location	Type	Reach	Directional Element	Fault Phase Identification
75%	AG	Correct operation	Operation with chattering	Mis- classification
	ABG	Correct operation	Operation with chattering	Mis- classification
	AB	Correct operation	Operation with chattering	Mis- classification
85%	AG	Correct operation	Operation with chattering	Mis- classification
	ABG	Correct operation	Operation with chattering	Mis- classification
	AB	Correct operation	Operation with chattering	Mis- classification

5.2.3 Scenario 3

Figure 75 and Figure 76 show the response of the directional element during a phase-to-phase fault and a single phase to ground fault simulated at 85% of the total length of the transmission line for GFM BESS without negative sequence control.

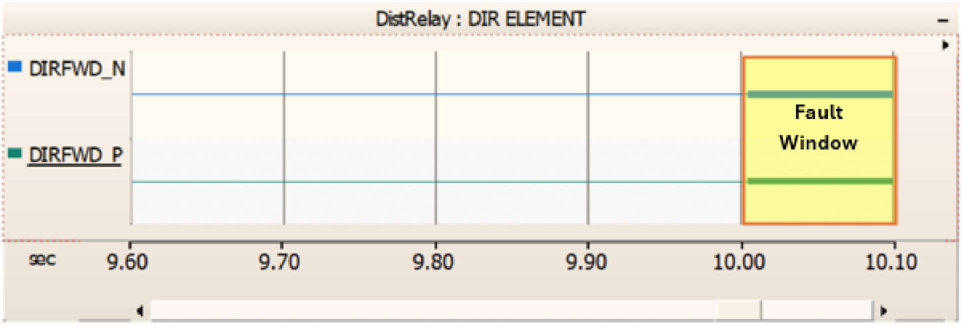


Figure 75 Directional element during phase-to-ground fault at 85%

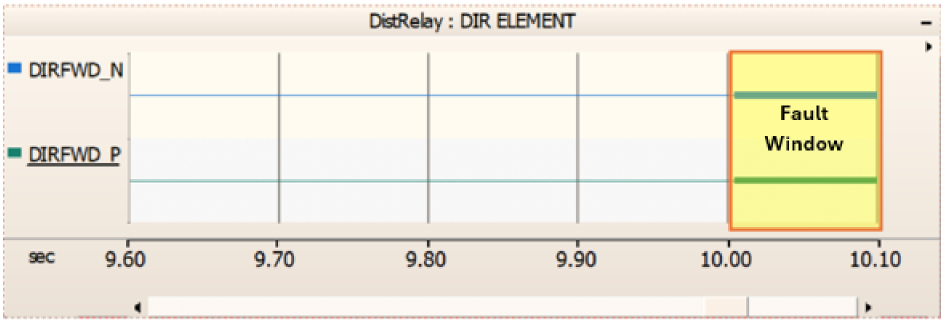


Figure 76 Directional element during phase-to-phase fault at 85%

Table 22 shows the results for the GFM BESS scenario without negative sequence control.

Table 22 Results for GFM BESS

Fault Location	Type	Reach	Directional Element	Fault Phase Identification
75%	AG	Correct operation	Correct operation	Correct operation
	ABG	Correct operation	Correct operation	Correct operation
	AB	Correct operation	Correct operation	Correct operation
85%	AG	Correct operation	Correct operation	Correct operation
	ABG	Correct operation	Correct operation	Correct operation
	AB	Correct operation	Correct operation	Correct operation

5.2.4 Scenario 4

Figure 77 and Figure 78 show the response of the directional element during a phase-to-phase fault and a single phase to ground fault simulated at 85% on the transmission line for synchronous generator scenario. Results indicate steady directional identification during fault window.

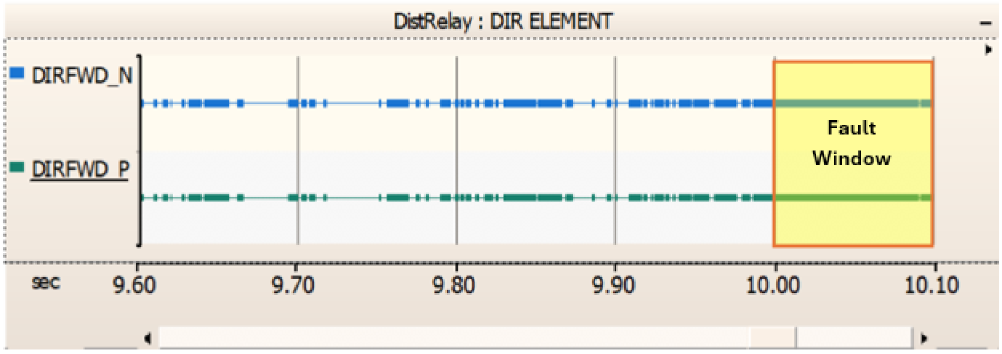


Figure 77 Directional element during phase-to-ground fault at 85%

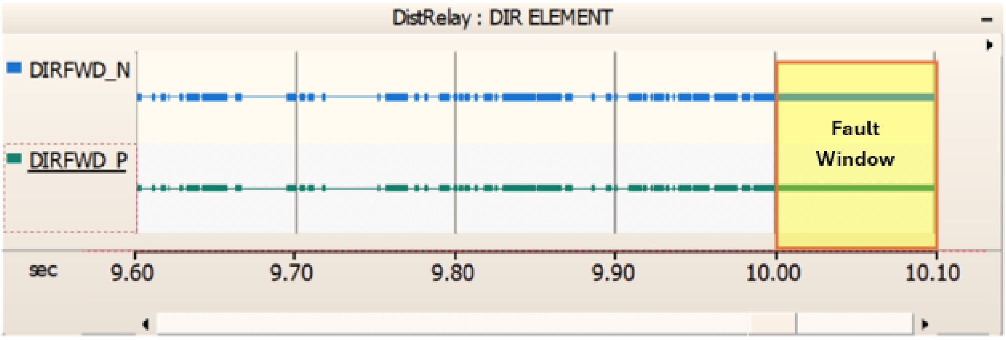


Figure 78 Directional element during phase-to-phase fault at 85%

*Note that any fluctuations observed during pre-fault conditions are observed due to measurement noise and can be disregarded.

Table 23 shows the summary of the results for synchronous generator scenarios demonstrating the intended behaviour of the protection relays.

Table 23 Results for Synchronous Generator

Fault Location	Type	Reach	Directional Element	Fault Phase Identification
75%	AG	Correct operation	Correct operation	Correct operation
	ABG	Correct operation	Correct operation	Correct operation
	AB	Correct operation	Correct operation	Correct operation
85%	AG	Correct operation	Correct operation	Correct operation
	ABG	Correct operation	Correct operation	Correct operation
	AB	Correct operation	Correct operation	Correct operation

The study identified the following deficiencies in other relays.

- Relays R4 and R6 had their directional elements activate during reverse faults occurring near the 330/500 kV station, though no actual maloperations resulted due to the reach element functioning correctly.
- Additionally, Relay R3 exhibited misclassifications under forward fault conditions, mirroring the behaviour that had previously been observed in Relay R5.

5.2.5 Impact of negative sequence control

To evaluate the impact of NS control, simulations were repeated after enabling the NS control of GFL BESS and Type-4 Windfarm.

GFL BESS with and without negative sequence current control

When the GFL BESS simulations were rerun with negative sequence control activated, the results demonstrated improved fault direction identification (with less chattering) and improved faulted phase identification for single phase to ground faults. Results are compared in Table 24.

Table 24 Results for GFL BESS with and without Negative Sequence Control

Fault Location	Type	Reach		Directional Element		Fault Phase Identification	
		Without NS	With NS	Without NS	With NS	Without NS	With NS
75%	AG	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Correct operation
	ABG	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Mis-classification
	AB	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Mis-classification
85%	AG	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Correct operation
	ABG	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Mis-classification
	AB	Correct operation	Correct operation	Operation with chattering	Operation with less chattering	Mis-classification	Mis-classification

Wind Farm with and without negative sequence control

Table 25 shows the comparison of results for Windfarm with and without NS control. Results showed improved fault direction identification results with the inclusion of the NS control. However, there were some deficiencies in fault classification.

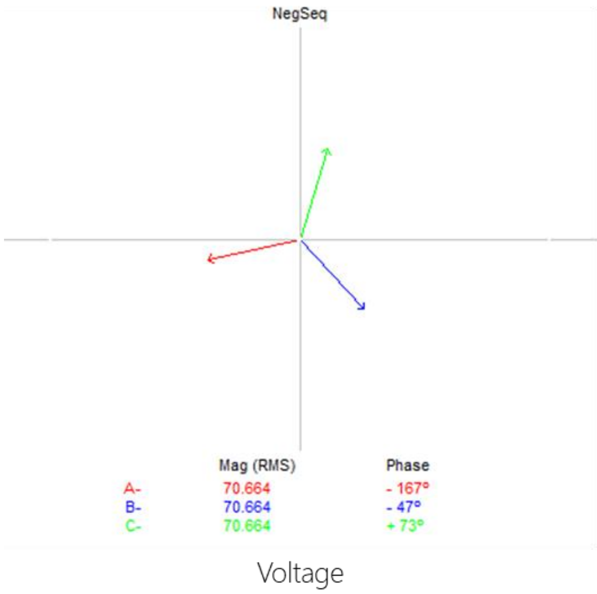
Table 25 Results for Type 4 Windfarm with and without Negative Sequence Control

Fault Location	Type	Reach		Directional Element		Fault Phase Identification	
		Without NS	**With NS**	**Without NS**	**With NS**	**Without NS**	**With NS**
75%	AG	Correct operation	Correct operation	Delayed operation with chattering	Correct operation	Correct operation	Correct operation
	ABG	Correct operation	Correct operation	Failure to operate	Failure to operate	Correct operation	Mis-classification
	AB	Correct operation	Correct operation	Failure to operate	Failure to operate	Correct operation	Mis-classification
85%	AG	Correct operation	Correct operation	Delayed operation with chattering	Correct operation	Correct operation	Correct operation

Fault Location	Type	Reach		Directional Element		Fault Phase Identification	
		Without NS	With NS	Without NS	With NS	Without NS	With NS
	ABG	Correct operation	Correct operation	Failure to operate	Failure to operate	Correct operation	Correct operation
	AB	Correct operation	Correct operation	Failure to operate	Failure to operate	Correct operation	Correct operation

To supplement the results presented in Table 25, Figure 79 and Figure 80 show negative sequence voltage and current phasors during L-G fault and following outlines key observations.

- When the negative sequence control is disabled, the angle difference between negative sequence voltage and current reaches approximately 88° (leading). This is closer to preferred 90° (leading) angle difference resulting into chattering of the direction relay.
- When the negative sequence control is enabled, the angle difference between negative sequence voltage and current reaches approximately 133° (leading). This results in accurate operation of directional element without chattering.



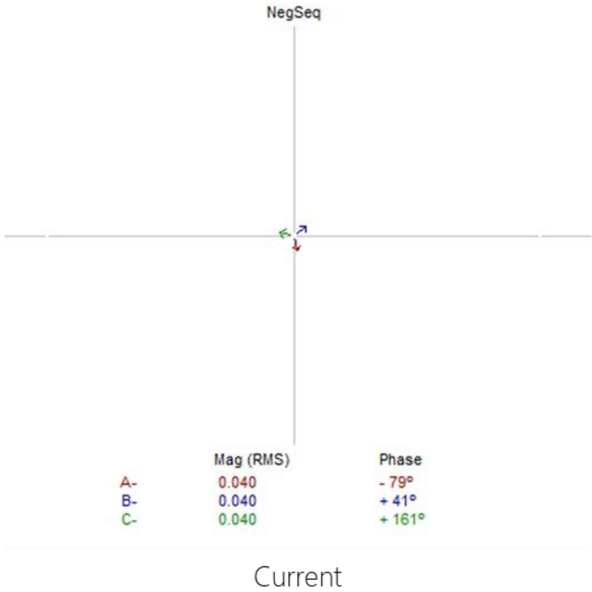


Figure 79 Negative sequence voltage and current phasors (negative sequence control disabled) for L-G fault

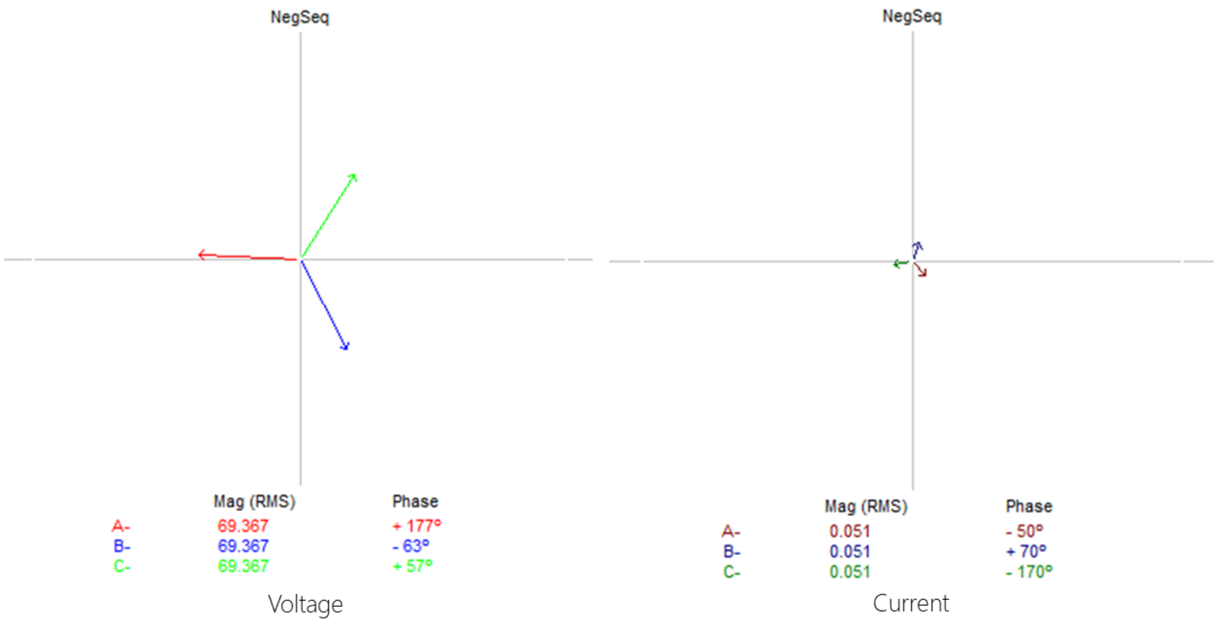


Figure 80 Negative sequence voltage and current phasors (negative sequence control enabled) for L-G fault

5.3 Summary of findings from simulation studies

A simulation-based analysis was conducted using the PSCAD/EMTDC simulation program. Distance relays were modelled in detail including directional protection element and faulted phase identification logic. To evaluate the performance of the relays, faults were simulated at various locations on the line. Results demonstrated performance deficiencies in direction and faulted phase identification mainly due to uncontrolled negative sequence injections from IBRs. The GFM BESS demonstrated improved results compared to other IBR considerations (Type-4 windfarm and GFL BESS without NS control).

Protection schemes employing directional overcurrent functions and communication-aided configurations are potentially vulnerable to mal-operations, given their dependence on directional elements. It should be noted that the results may vary depending on the type, response, parameters, etc. of the IBR equipment/relay type used and results presented in this report may not be generalized.

However, this analysis demonstrates the unpredictable nature of IBRs in negative sequence current injections impacting the performance of the distance protection relays applied to transmission systems.

6 Draft Technical Standards for GFM with respect to impact on protection

This section presents draft technical standards for GFM based on the learnings and power system analysis presented in Part I (GFL and GFM inverters under negative-sequence voltage conditions), specifically the comparisons between various standards and guidelines presented in Section 2.6, power system studies carried out in Section 3 of Part I and Section 5.2 of Part II.

6.1 International Standards comparison

Table 26 compares the current Australian NER requirements (including ERC0393 amendments, May 2025) against IEEE 2800-2022, German grid codes (VDE-AR-N 4120/4130), and VDE FNN (2025) guidance for GFM units, identifying gaps relevant to protection-compatible negative-sequence behaviour.

Table 26 International standards comparison – focused on negative-sequence requirements for IBRs

Aspect	NEM / NER (S5.2.5.5A, ERC0393)	IEEE 2800-2022	VDE-AR-N 4120 / FNN 2025	Gap / Recommendation
Negative-sequence reactive current injection	S5.2.5.5A (ERC0393, May 2025): requires negative-sequence reactive current injection to avoid excessive voltage rise on healthy phase(s) during unbalanced faults. Positive Sequence reactive current injection of 4% (capacitive) and 6% (inductive) of the maximum continuous current is required at AAS, that is applicable to both balanced and unbalanced faults. Negative-sequence current injection required to oppose unbalanced voltages but quantitative slope/k-factor not explicitly mandated.	IBRs shall inject negative-sequence current dependent on terminal V_2. Full converters: I_2 must lead V_2 by 90–100°. Type-III (DFIG): 90–150° tolerance. Response rise time ≤2.5 cycles to 90% of required I_2.	k-factor between 2 and 6 for negative-sequence. Reactive current proportional to V_2 with same gain as positive-sequence. Explicit requirement to avoid overvoltage on unfaulted phases.	NER lacks an explicit k-factor range or mandatory phase-angle specification for negative-sequence current injection. International standards provide clearer, measurable performance envelopes. The k-factor is typically defined with reference to reactive current injection (specifically at the NER). However, under low SCR and low X/R conditions, active (d-axis) current can have a significant impact on voltage. While the NER currently acknowledges this effect, no quantitative metric is provided. It is noted that under low SCR condition particularly with low X/R ratios active current has a greater impact on voltage; therefore, its effects need to be reflected more quantitatively at the NER with reference to grid SCR and X/R conditions.
Phase-angle requirement ($\angle I_2$ vs V_2)	Not explicitly specified. Implied through the requirement to minimise voltage deviation on each	90–100° leading (full converters); 90–150° (Type-III). Tight tolerance ensures predominantly reactive I_2.	Predominantly reactive (inductive impedance). VDE FNN (2025) recommends R/X ≈ 0.1 for GFM,	NER does not prescribe a phase-angle window. Without this, relay directional elements and faulted-phase identification may be unreliable with IBR fault current.

Aspect	NEM / NER (S5.2.5.5A, ERC0393)	IEEE 2800-2022	VDE-AR-N 4120 / FNN 2025	Gap / Recommendation
	phase from pre-disturbance levels.		ensuring ~90° leading.	
Current-limit handling and voltage-source preservation for GFM	No specific guidance on current-limit strategy or preservation of voltage-source behaviour during limiting.	Proportional curtailment of I_1 and I_2 preferred. Active- or reactive-priority modes permitted. Must respect I_max.	Voltage-source behaviour must be maintained even at current limit. Regulate to 95–100% of I_max without hard clipping. Impedance fold-back approach recommended.	NER does not address how GFM inverters should behave at current limits. This is critical for protection-quality fault current and relay dependability.
Timing / response speed	S5.2.5.5A AAS: positive-sequence reactive current response must commence within 10 ms; rise time ≤40 ms for step-like voltage profile.	Rise time <2.5 cycles (<50 ms at 50 Hz) to reach 90% of required I_2. Settling within 4 cycles.	Rise time 60 ms (VDE-AR-N 4120). Settling typically within 4 cycles.	NER timing requirements are broadly comparable for positive-sequence but do not explicitly extend timing specifications to negative-sequence response. This is especially important when positive sequence current prioritisation is applied over negative sequence or converters treat negative-sequence current as a disturbance or auxiliary control.
Deadband / steady-state unbalance	Voltage unbalance system standard in S5.1a (negative-sequence voltage). No explicit deadband for IBR negative-sequence control activation.	Not explicitly mandated but commonly implemented at 2–3% V_2.	Allows minor internal V_2 to limit continuous I_2 for unbalances below ~3% of rated current.	A deadband specification would prevent unnecessary continuous I_2 injection and associated thermal stress on IBR hardware.
GFM-specific requirements	AEMO Statement of Need (clause 3.11.12(a)): GFM Inverter Protection-Quality Fault Current Trial. No GFM-specific access standards yet codified in NER S5.2.5.	IEEE 2800 primarily written for GFL; GFM-specific interpretations handled via supplementary guidance.	Comprehensive GFM guidance including Thevenin-equivalent behaviour, Z_2,eff = Z_1,eff, impedance fold-back at limits, phase-jump response. Most detailed international GFM framework.	NER has no GFM-specific technical requirements. As GFM BESS and solar are deployed in the NEM, explicit standards for voltage-source behaviour, negative-sequence impedance matching, and current-limit handling are needed.

6.2 Draft technical requirements and verification method

The following requirements should be considered as additions or amendments to NER Schedule 5.2 for GFM inverters. Each requirement specifies a measurable criterion, the reasoning behind its inclusion, the source standards and evidence, and a verification method. These are presented as guideline principles for industry consideration and debate before finalisation.

Table 27 Draft technical standards for GFM

ID	Requirement	Measurable Criterion	Rationale	Verification Method
DS-1	Negative-sequence	$\angle(I_2) = \angle(V_2) + 90°$ (±10° tolerance)	Supports directional relay operation (67Q) and faulted-phase	SMIB EMT simulation. Apply L-G, LL-G faults at connection point.

ID	Requirement	Measurable Criterion	Rationale	Verification Method
	reactive current phase angle		identification. Aligned with IEEE 2800 for full converters and the impedance-based response of well-tuned GFM inverters.	Measure one-cycle DFT phasors. Confirm ∠(I_2) relative to ∠(V_2) within 80–100° leading for ≥95% of fault duration samples.
DS-2	Negative-sequence reactive current gain (k-factor or equivalent impedance)	k = $\lvert I_2\rvert/\lvert V_2\rvert$ in range 2–6, equivalent to Z_2,eff ≈ 0.17–0.50 pu. For GFM: Z_2,eff ≈ Z_1,eff during normal operation.	Ensures sufficient I_2 magnitude for relay pickup (50Q/51Q) and proportional voltage rebalancing. Range consistent with German TCR and VDE FNN guidance.	Vary V_2 from 0.05 to 0.5 pu in SMIB. Plot $\lvert I_2\rvert$ vs $\lvert V_2\rvert$; confirm slope within k = 2–6 band outside current-limit region.
DS-3	Activation deadband	Negative-sequence control activates when VUF > 2–3% (V_2/V_1 > 0.02–0.03 pu)	Prevents continuous I_2 injection for minor steady-state unbalances, reducing thermal stress and DC-link ripple while ensuring response to genuine fault conditions.	Steady-state simulation with V_2 ramped from 0 to 5%. Confirm zero I_2 response below deadband threshold and proportional response above.
DS-4	Response timing (negative-sequence)	Negative-sequence reactive current must commence within 20 ms of fault inception and reach 90% of required magnitude within 2.5 cycles (50 ms at 50 Hz). Settling within 4 cycles (80 ms).	Protection relay operating times in the NEM are typically around 120 ms for primary protection. I_2 must be established within the relay measurement window for dependable fault detection.	Time-domain EMT simulation of L-G fault. Measure I_2 rise time as per the grid-code requirements.
DS-5	Current-limit handling (GFM-specific)	At current limit: (a) maintain voltage-source behaviour by increasing Z_2,eff (impedance fold-back) rather than hard clipping; (b) regulate current to 95–100% of I_max; (c) proportionally reduce I_1 and I_2 to preserve phase relationship; (d) restore nominal impedance within 2–4 cycles of fault clearance.	Hard current clipping destroys voltage-source properties and distorts I_2 phasing, undermining relay directional elements. VDE FNN (2025) and AR-PST Stage 5 findings confirm impedance fold-back preserves protection-compatible response.	EMT simulation of bolted L-G fault with I_max reached. Confirm: (i) ∠(I_2) remains within ±15° of target during limiting; (ii) current waveform THD < 10% during sustained limiting; (iii) full voltage control restored within 80 ms of fault clearance.
DS-6	Impedance symmetry (GFM-specific)	Z_2,eff / Z_1,eff within 0.8–1.2 during normal operation and prior to current limiting	Ensures GFM shares unbalanced fault current in proportion to its balanced contribution, consistent with synchronous machine analogy. Prevents circulating negative-sequence currents between parallel GFMs.	Measure effective positive- and negative-sequence impedance from SMIB V/I phasors during L-G fault (pre-current-limit region). Compute ratio.
DS-7	Voltage unbalance mitigation	During unbalanced faults: faulted-phase voltage ≥0.5 pu (indicative) and unfaulted-phase voltage ≤1.1 pu at connection point, for fault conditions within the access standard ride-through envelope.	Overvoltage on unfaulted phases can damage equipment and trigger spurious protection trips. Adequate I_2 injection reduces VUF and limits phase-voltage excursions.	Network EMT simulation with representative IBR penetration. Monitor instantaneous phase voltages at connection point during L-G and LL-G faults.
DS-8	Direction of negative-sequence current	During fault: net negative-sequence current flows from IBR toward the grid (injection convention, not absorption)	Injection reduces residual V_2, supports voltage rebalancing, and provides correct directional information for 67Q elements. Absorption worsens unbalance.	Confirm sign convention in EMT results: device-to-grid I_2 is positive; verify I_2 direction is toward fault for all tested fault types.

6.3 Implementation Considerations

The following outlines a high-level principle-based approach to further refinement and implementation of draft standards.

- NER integration: Requirements DS-1 through DS-4 and DS-7 and DS-8 apply to all IBR types (GFL and GFM) and should be incorporated into a revised S5.2.5.5A. Requirements DS-5 and DS-6 are GFM-specific and could form a new sub-clause or be included in GFM-specific schedules as AEMO potentially develops the regulatory framework following the Protection-Quality Fault Current Trial.
- Verification practice: All verification should use validated EMT-grade models (PSCAD or equivalent) with full control representation, not simplified positive-sequence-only models. Phasor measurements should use a one-cycle DFT moving window consistent with IEEE 2800 conformity assessment methods. Both SMIB and representative network studies should be conducted.
- Transitional approach: For projects already in the connection pipeline, these requirements could initially be applied as negotiated access standards (NAS) with a pathway toward automatic access standard (AAS) inclusion in a future NER amendment.
- OEM coordination: Requirements should be communicated to inverter OEMs to ensure control firmware supports the specified negative-sequence behaviour, deadband settings, and current-limit strategies. Compliance testing protocols should be developed collaboratively with industry.

Part III Modelling framework for IBLs

7 IBL interface specification for model structure and performance mapping

7.1 Objective and scope

The objective of Task 3 is to define a modular, technology-neutral interface specification and modelling framework for inverter-based loads (IBLs), applicable to both phasor-domain transient (PDT) and electromagnetic transient (EMT) simulation environments.

Task 3 is intended to be used as a practical "translation layer" between IBL technology diversity and the study questions that the system operators and network owners need to answer. The interface specification defines a consistent set of modules, signals, states, limits, timers and mode logic, so that different IBL technologies and vendors can be represented in a comparable way. The framework supports two complementary pathways: (i) PDT models for wide-area screening and scenario studies, parameterised to reproduce connection-point behaviour over study-relevant timeframes, and (ii) selective EMT benchmarking where millisecond-scale dynamics, mode transfers, or interaction-sensitive behaviours may influence conclusions.

The framework is supported by an outcome-based modelling philosophy, where models are structured to reproduce externally observable behaviour at the point of connection, rather than internal implementation details [44]. Representative functional performance expectations, such as behaviour during voltage disturbances, response under low system strength, and sensitivity to unbalanced conditions, are used to guide model structure and parameterisation. These expectations are not intended as requirements, but as a means of ensuring that resulting models are credible, study-relevant, and technically plausible for system-level assessment.

Consistent with this approach, the modelling boundary is defined at the connection point, and priority is given to the accurate reproduction of observable quantities, including voltage, current, active power, reactive power, and their timing and sequencing during and after disturbances. Internal architecture, control philosophy, and design choices remain unconstrained, provided the aggregate response at the connection point is represented in a manner consistent with expected physical behaviour.

This task does not define access standards, compliance criteria, or performance limits, nor does it seek to imply preferred control strategies or technology selections. Instead, it establishes a common structural and behavioural foundation that can support:

- scalable simulation studies across a wide range of network conditions,
- model validation, benchmarking, and comparison across technologies and sites, and
- future development of technical guidance or performance frameworks, should these be required in later stages of the program.

Task 3 produces: (i) a technology-neutral module inventory and interface template (inputs, outputs, internal states, limits, timers and counters), (ii) a behaviour library mapping observable signatures to modelling features, (iii) generic supervisory state-machine patterns for transfer, recovery and reconnection, and (iv) guidance for parameterisation and benchmarking across PDT and EMT domains.

The scope explicitly covers major classes of IBLs, including but not limited to:

- data centres and other UPS-dominated facilities,
- electrolysers (alkaline, PEM, and hybrid configurations),
- EV fast-charging infrastructure, and
- industrial variable-speed drives and rectifier-fed processes.

To ensure applicability across diverse IBL architectures and levels of study complexity, the framework focuses on identifying common functional building blocks that recur across technologies. These include, for example, grid-facing rectification stages, DC-link dynamics, inverter stages where present, supervisory mode and transfer logic, embedded energy buffering elements, and auxiliary or process subsystems with slower recovery dynamics.

A data centre is used as a representative worked example, reflecting its well-documented internal layering and system relevance, to illustrate modular decomposition and the mapping between internal subsystems and observable behaviour at the connection point in both EMT and PDT study domains. The intent is illustrative rather than normative, demonstrating how the proposed interface specification can be applied without constraining its use to a single technology class.

The specification is designed to minimise reliance on sensitive OEM intellectual property. It constrains only what must be observable at the connection point and the minimum internal state needed to reproduce that behaviour (for example mode flags, timers, counters, limit activation and aggregated energy state), while leaving internal design choices unconstrained.

7.2 Recommended application workflow

To make the Task 3 outputs directly usable in studies and stakeholder engagements, the following practical workflow is recommended:

- **Define the study question and operating context**: specify whether the focus is on fault ride-through, voltage recovery, reclosing sequences, interaction risk in weak grid conditions, restoration and recovery, or fleet coincidence effects, and confirm the relevant operating modes.
- **Apply screening cues to identify material behaviours**: use electrical significance, local system strength, converter density, clustering, and load composition to determine which behavioural groups are likely to influence outcomes.
- **Select the required behavioural signatures** from the behaviour library (Table 30): identify the observable connection-point quantities and event sequences that must be reproduced (for example, voltage sag response, phase-angle step response, successive disturbance logic, recovery and recharge trajectory).
- **Map behaviours to dominant modules and minimum modelling features** (Table 32 and Table 36): identify which modules must be explicit (for example, M1, M2, M9, M10) and which features are essential (limits, latches, timers, counters, segmentation, ramp limits).
- **Choose modelling domain and scope** (Table 37): use PDT models for scalable wide-area screening and scenario studies, and EMT models selectively for benchmarking fast or interaction-sensitive phenomena and for informing the parameterisation of PDT abstractions.
- **Parameterise the model using externally visible descriptors** (Table 34 and module templates): set limits, delays, transfer criteria, disturbance counter windows, reconnection inhibits, ramp-

rate limits, recovery sequencing, and critical versus non-critical segmentation fractions in a manner consistent with credible operating envelopes.

- **Validate and assign confidence using the evidence hierarchy**: benchmark against available evidence (in-service disturbance replay where available, factory or integration evidence, and reasonableness checks) and record a confidence grade per behaviour group together with residual uncertainty assumptions carried into studies.
- **For fleet and hub studies, apply the Diversity Parameter Set (DPS)**: represent diversity, correlation, and coincidence risk using bounded envelopes, scenario ensembles, or stochastic sampling as appropriate to the study objective.

7.3 Background and motivation

IBLs incorporate diverse combinations of power-electronic interfaces, control layers, and auxiliary subsystems, implemented to meet objectives such as continuity of supply, process stability, efficiency, and asset protection, rather than explicit grid-support functions. As a result, their internal architectures, control strategies, and disturbance responses vary materially across technologies and applications, even where nameplate ratings or connection voltages appear similar.

Detailed studies of large IBLs show that these facilities are not single homogeneous demands, but tightly coupled aggregations of subsystems, including grid-facing rectifiers, DC-link networks, DC/DC converters, inverter stages where present, embedded energy buffers, internal distribution networks, and site-level supervisory and protection logic. These subsystems interact dynamically and collectively determine how the load responds to voltage disturbances, unbalanced conditions, weak-grid environments, and restoration sequences. The layered nature of these architectures means that externally observable behaviour at the connection point is often governed by internal control and energy-management logic, rather than by the downstream process or IT demand itself.

Experience from detailed EMT modelling and international operating experience demonstrates that, for many large IBLs, disturbance behaviour is dominated by the grid-facing power-electronic interface and DC-link regulation. Downstream loads typically set the steady-state active power demand profile, while converter controls, DC voltage management, and supervisory logic determine fault ride-through characteristics, current limiting behaviour, conditional transfer to internal supply, and reconnection timing. This separation between steady-state demand drivers and disturbance-response drivers is a key departure from traditional load-modelling assumptions and is not readily captured by conventional representations.

The system risk is not only the magnitude of a single disturbance response, but also the timing and coherence of responses across multiple sites [45] [11]. For IBLs with supervisory mode logic and energy constraints, small differences in thresholds, timers and counters can determine whether a site rides through, reduces demand, or transfers to internal supply, and when it returns. This can materially affect voltage recovery, frequency excursions, and coincident load steps during restoration. The same issue arises under aggregation, because coincident behaviour can emerge even when each individual site appears benign in isolation, particularly when similar supervisory logic and limits are deployed across a fleet.

Commonly used load models in power system studies are generally not designed to represent these mechanisms [46]. Static ZIP models and composite load models with simple threshold-driven disconnection logic can approximate steady-state demand and bulk offloading behaviour, but they do not capture internal state evolution, time-dependent control actions, or mode transitions [47], [48], [49], [50]. In particular, they are unable to represent near-constant power behaviour with current limiting during voltage depressions, DC-link saturation or collapse, conditional transfer governed by supervisory logic, or staged reconnection and recovery processes that include energy buffer recharge and auxiliary system restart.

These limitations can distort study outcomes in both directions [50], [51]. Simplified models may understate risk by masking correlated or coincident responses across multiple IBL sites, particularly where similar control philosophies or disturbance-counting logic are deployed. Conversely, they may overstate risk by assuming immediate and complete disconnection for disturbances that, in practice, would be ridden through or managed internally. Both effects introduce uncertainty into assessments of voltage recovery, frequency stability, system strength margins, and interaction risk in converter-dense or weak-grid environments [52].

Recent international work and utility-led investigations using EMT benchmarking and disturbance-event replay indicate that a more effective modelling approach is to focus on externally observable behaviour at the connection point, rather than attempting to replicate or prescribe internal design details [53], [54], [20]. By identifying which internal subsystems and control layers drive specific observable responses, models can be structured modularly, allowing dominant behaviours to be represented credibly without requiring full OEM disclosure or technology-specific assumptions.

This motivates the development of a modular, outcome-based modelling framework for IBLs, in which common functional building blocks are identified across technologies and mapped explicitly to their system-level relevance [46], [51]. Rather than focusing on any single load category, Task 3 targets recurring structural and behavioural patterns that appear across data centres, electrolysers, EV fast-charging infrastructure, and industrial converter-fed processes. A data centre is used as a representative example to illustrate this approach, not because it is unique, but because its layered power-electronic structure and disturbance behaviour are well documented and provide a clear demonstration of how internal subsystems map to observable responses in both EMT and PDT study domains.

Common gaps in conventional load representations (why the modular approach is needed) [50], [45]

Experience with large UPS-dominated facilities shows that several behaviours that matter for disturbance and recovery studies are commonly absent or reduced to oversimplified threshold actions. In particular:

- **UPS transfer and mode logic, including timers, latches, and disturbance counters;**
- **Current-limited, near-constant power behaviour** at the grid interface during voltage depressions;
- **Sensitivity to unbalanced conditions and phase-angle jumps**, often linked to PLL-based synchronisation in rectifier and inverter stages;
- **Delayed and staged reconnection**, including coupling between IT load restoration, cooling restart, and **battery recharge**, which can introduce active and reactive power transients well after fault clearance.

Composite load models can emulate bulk offloading, but they typically treat disconnection and reconnection as binary, and do not represent internal UPS control dynamics (DC-link regulation, PLL/synchronisation) or diversity across sites. These gaps motivate a modular representation in which the grid-facing conversion, DC energy state, and supervisory logic are explicit modelling elements that can be implemented consistently in both PDT and EMT studies.

7.4 Activity 1 – Technology characterisation

Across representative IBL types, a set of recurring architectural patterns can be identified, despite diversity in internal implementation, scale, and end-use application [46], [45]. These patterns arise from common functional needs, such as conversion between AC and DC, decoupling of upstream grid conditions from downstream processes, and coordination of operating modes to maintain continuity of service or process integrity. The intent of this section is not to catalogue vendor designs, but to characterise IBLs in terms of functional building blocks that shape externally observable behaviour at the point of connection, and that can be represented modularly in both EMT and PDT simulation environments.

Activity 1 characterises each IBL class in terms of recurring functional building blocks and the typical dominance of those blocks for disturbance response versus recovery response. This provides the input needed to select which modules are explicit for a given facility, and which behaviours from Activity 2 should be prioritised for parameterisation and benchmarking.

7.4.1 Recurring functional building blocks across IBLs

The following building blocks recur across the major IBL classes considered in this task (data centres, electrolysers, EV fast-charging infrastructure, industrial drives and rectifier-fed processes):

Grid interface and site transformers

Large IBL facilities commonly connect through dedicated transformers and internal distribution, with the grid interface and measurement boundary providing the reference point for model validation and benchmarking. For large campuses, this may be at transmission or sub-transmission levels [55].

AC–DC front ends

Most IBLs interface with the grid through rectifier-dominated front ends. These may be thyristor-based in some industrial applications, or voltage source inverter (VSI)-based using fast switching devices for more “grid-friendly” behaviour and better controllability. The AC–DC stage largely defines grid-facing current behaviour, including current limiting tendencies, sensitivity to voltage disturbances, and (where relevant) harmonics and commutation vulnerability.

DC networks and DC-link dynamics

A DC link or DC bus is central in many modern IBLs, providing decoupling between the grid-facing converter and the downstream process or IT load. DC-link and associated DC/DC stages can materially influence behaviour during voltage depressions, including whether the facility maintains power, reduces demand, or transitions mode under DC voltage or current constraints.

DC–AC stages where applicable

Some IBLs include DC–AC inverter stages to supply regulated internal AC, notably UPS-dominated data centres and many variable-speed drive applications. In contrast, many electrolysers and DC fast chargers remain predominantly DC-connected beyond rectification and may not require an internal DC–AC inversion stage for their core process supply.

Energy buffering elements

Embedded energy storage is common in UPS architectures (typically batteries and sometimes flywheels), and it strongly influences conditional transfer, duration of ride-through on stored energy and post-event recovery characteristics. Even where explicit storage is absent, DC-link capacitance provides short-timescale energy buffering that influences DC voltage stability during fast disturbances.

Auxiliary and process subsystems

Auxiliary systems such as pumps, fans, compressors and cooling plant can form a material fraction of facility demand and are increasingly inverter-driven, particularly in large cooling plants. These subsystems often do not dominate the immediate fault response, but they can dominate recovery trajectories through restart sequencing, ramping, and delayed load pick-up.

Supervisory control and mode logic

Across all IBL types, supervisory control coordinates operating modes, prioritisation of critical versus non-critical load blocks, transfer decisions, and reconnection and recovery sequencing. While the internal implementation is vendor- and site-specific, the presence of supervisory logic is a recurring architectural element that must be representable as a distinct module where mode transitions or conditional behaviour are material to studies.

Protection and limit logic

Fast current, voltage, and DC protection functions, ride-through modes, blocking, latches, and reconnect inhibits can dominate event timing and whether behaviour is state-dependent rather than threshold-only.

Power quality and filtering elements

Filters and harmonic mitigation, together with converter control bandwidth, can influence resonance sensitivity and harmonic amplification in weak or cable-rich networks, and may require dedicated representations where power-quality questions are in scope.

Table 28 Indicative component prevalence across major IBL types (technology characterisation view)

Component / building block	Electrolysers	EV fast-charging infrastructure	Data centres	Notes (why it matters for modelling)
Rectifier (AC–DC)	Common	Common	Common	Dominant grid-facing stage for many IBLs, defines current limiting and disturbance response
Inverter (DC–AC)	Not always	Mostly only for bidirectional cases	Common (UPS)	Data centres often rely on continuous inverter operation, affects transfer and recovery behaviour
DC/DC stages	Less common	Common	Common	Drives DC-link regulation, battery interface, and power limiting where present
DC link / DC bus	Common	Common	Common	Central energy buffer and constraint, drives ride-through capability, limiting, and recovery trajectory under DC constraints
Energy buffering (battery/flywheel, where applicable)	Variable	Variable	Common	Determines conditional transfer capability and duration, and creates recharge-driven recovery dynamics and possible “second event” behaviour

Component / building block	Electrolysers	EV fast-charging infrastructure	Data centres	Notes (why it matters for modelling)
Pumps, compressors, cooling	Common	Usually limited	Material	Strong influence on recovery trajectory, restart sequencing, delayed load pick-up, and potential Q swings
Supervisory control and mode logic	Common	Common	Common	Timers, counters, latches, prioritisation (critical vs non-critical), transfer decisions and reconnection sequencing, often dominates study outcomes
Bypass/transfer equipment (UPS/STS), where applicable	Rare	Rare	Common	Drives rapid mode changes and connection-point steps, interacts with reclosing and protection practices, must be represented as explicit logic where material
Protection and limit logic	Common	Common	Common	Latches, inhibits, limit activation timing, and momentary cessation behaviour can dominate event sequencing and conditional response
Power quality and filtering elements	Variable	Variable	Variable	Resonance sensitivity and harmonic amplification in weak or cable-rich networks, often study-specific inclusion

7.4.2 Worked example characterisation, data centre anatomy

Data centres are used as a representative worked example because their internal layering is well defined and maps clearly onto externally observable behaviour. At a high level, a modern data centre typically comprises grid interface and transformers, UPS rectification stages, DC link and DC/DC stages, inverter stages supplying regulated AC to IT loads, embedded energy storage, cooling and auxiliary systems (often variable frequency drive (VFD)-driven), and site-level supervisory control and protection coordinating transfer and reconnection.

From the perspective of grid interaction, three subsystems are particularly useful for technology-neutral characterisation because they map directly to connection-point behaviour: the server farm, the UPS, and the cooling system and ancillary loads. The server farm determines the primary MW demand profile in normal operation, the UPS governs the disturbance response and any transition to stored energy, and cooling and ancillary systems are often more material during post-fault recovery due to restart logic and ramping.

Table 29 Data centre subsystem characterisation mapped to connection-point behaviour

Subsystem	Primary role in studies	Typical connection-point quantities affected
Server farm	Sets normal-operation MW demand profile	MW profile, slower variability driven by workload scheduling
UPS (rectifier, DC link, DC/DC, inverter, bypass)	Dominates disturbance behaviour and transfer decisions	Current limiting, effective constant-power tendencies, transfer timing, recovery shaped by recharge and limits
Cooling and ancillary systems (often VFD-driven)	Often dominates recovery phase	Restart sequencing, delayed load pick-up, ramping, reactive power swings
Site supervisory control and protection	Coordinates prioritisation, transfer, reconnection	Timers, counters, sequencing, segmentation (critical vs non-critical)

Many facilities also include onsite generation (often diesel or gas generator sets) to support extended outages. For most current designs, generator contribution is typically not present during the initial grid-connected disturbance interval, because start-up and synchronisation occur only after transfer to internal supply, but it can be relevant for longer-duration restoration and staged re-energisation studies.

For reference, the data centre worked example maps naturally to the module inventory used later in Activity 3, for example grid interface and transformer (M0), rectifier or active front end (M1), DC link and energy state (M2–M3), inverter and bypass/transfer where present (M4–M5), critical and non-critical blocks (M6–M7), auxiliaries such as cooling (M8), and supervisory and protection logic spanning the facility (M9–M10).

Static bypass, transfer equipment, and coordination considerations (data centre specific, but transferable)

In UPS-based architectures, a static bypass provides a parallel AC path that can be used during inverter faults or overloads, and separate static transfer switches (STS) may be used to transfer feeders between independent sources. Coordination of transfer thresholds and timing with site protection and upstream reclosing practices can be important to avoid nuisance transfers during grid faults.

Note on topology diversity: While double-conversion UPS architectures are common in many existing facilities, they should not be assumed as universal, particularly for newer large installations and AI-driven sites. Alternative topologies include distributed or rack-level UPS designs, and hybrid approaches that place significant energy storage downstream of the traditional UPS boundary, which can reduce reliance on double conversion but may expose parts of the IT supply chain to power-quality disturbances depending on operating mode and site automation. In addition, modelling assumptions can change materially if the UPS is operated with the bypass path closed, because the rack-level supplies may then be more directly exposed to grid voltage. The worked example is therefore illustrative of one prevalent topology, and the interface specification is intended to remain valid across alternative data-centre architectures by focusing on observable connection-point behaviour and the minimum retained state required to reproduce it.

7.4.3 Relationship to inverter-based resource models

Some converter building blocks overlap with those used in inverter-based resources (IBRs), particularly VSI stages and DC-link dynamics [44] [2]. However, IBLs are distinguished by different primary objectives, including continuity of supply and process stability, and by their energy constraints and recovery trajectories. These differences limit direct reuse of generation-oriented models without adaptation and motivate an IBL-focused characterisation and interface specification centred on observable load behaviour.

7.5 Activity 2 – Performance mapping of key IBL behaviours

This activity maps functional IBL behaviours to (i) why they matter in system studies and (ii) what needs to be represented in models to reproduce connection-point behaviour credibly. The mapping is explanatory and study-focused, consistent with the non-prescriptive intent set out in Section 7.1.

The mapping is framed in terms of externally observable quantities at the connection point, including voltage, current, active power, reactive power, and the timing and sequencing of changes during and after disturbances. This framing is useful because several behaviours that dominate system outcomes are conditional, state-dependent, and governed by supervisory logic, which is not represented well in static ZIP or threshold-only load models [47], [49]. For example, segmented and counter-based UPS transfer decisions, current-limited near-constant power behaviour, and delayed recovery processes (including staged reconnection and energy buffer recharge) are commonly oversimplified in conventional composite load representations.

Note: for many UPS-dominated facilities, transfer-to-backup and the subsequent reconnection and recovery profile should be treated as part of the same event, because recovery can create a material 'second event' if it is rapid or coherent.

7.5.1 Definitions of key event responses

In IBL studies, several distinct response mechanisms are often conflated in simplified representations. For clarity, the following definitions are adopted in this report:

- **Momentary cessation**: a time-dependent control or protection response in which the grid-facing converter temporarily ceases, or materially reduces, current exchange at the connection point (and may subsequently resume normal operation) without the defining feature being a sustained transition to internal supply. Momentary cessation may be triggered by voltage magnitude, phase-angle disturbance, unbalance, overcurrent, or internal limit/protection logic, and its impact is dominated by timing, latches, and recovery conditions.
- **Transfer to internal supply**: a supervisory mode transition in which the facility continues supplying some or all internal demand from an internal source (for example UPS battery/flywheel, or onsite generation once started and stabilised), such that grid-supplied active power reduces materially (often to near zero for the critical block). Transfer behaviour is defined by detection criteria, timers/counters, segmentation (critical versus non-critical), and return-to-grid criteria.
- **Offloading and load shedding**: a reduction in grid-supplied demand due to curtailment or shedding of internal load blocks, rather than due to internal supply. Offloading may be automatic (protection or limit-driven) or supervisory (prioritisation logic), and it can occur with or without transfer to internal supply.
- **Reconnection and recovery**: the staged return-to-grid and restoration trajectory following a disturbance or transfer, including reconnection inhibits, controlled ramps, non-critical block restoration, auxiliary restart sequencing, and energy buffer recharge. Recovery may create a material "second event" through coherent ramps, step changes, or reactive power transients well after fault clearance.

7.5.2 Connection-point behavioural archetypes

To make the mapping concrete, it is helpful to describe a small set of illustrative response "archetypes" observed in detailed investigations of large power-electronic loads (particularly UPS-based facilities). These archetypes are not intended to imply universal behaviour across all sites, but they provide practical templates for what connection-point responses can look like, and what model features are needed to reproduce them.

Archetype A: Shallow voltage disturbance, grid-connected ride-through with near-constant active power

Many facilities can maintain active power across a range of shallow voltage depressions, up to limits imposed by converter current limits, protection thresholds, and DC-link constraints.

Connection-point current can increase as voltage falls, with reactive power changing depending on control and limits.

Archetype B: Deeper disturbance, conditional transfer to internal supply
For more severe disturbances, supervisory logic may trigger transfer to internal energy storage, producing a rapid reduction of grid-supplied active power, followed by a recovery trajectory shaped by reconnection logic and recharge behaviour.

Archetype C: Phase-angle disturbance response (including ride-through cases)
Converter synchronisation and control can yield distinctive responses to phase-angle jumps, including changes in P and Q and, in some implementations, conditional transfer depending on thresholds and timing. Illustrative cases exist where large phase-angle jumps are ridden through without interruption, highlighting that automatic assumptions of "low tolerance" can be misleading.

Archetype D: Successive fault tolerance and disturbance-counting logic
A practically important feature in some UPS implementations is tolerance to successive faults and time-dependent decision-making using counters and windows. This can be study-critical where repeated voltage disturbances occur in quick succession (including upstream auto-reclosure), because time window and counter-based logic can dominate whether the site rides through or transfers. This behaviour is often missing from simplified models.

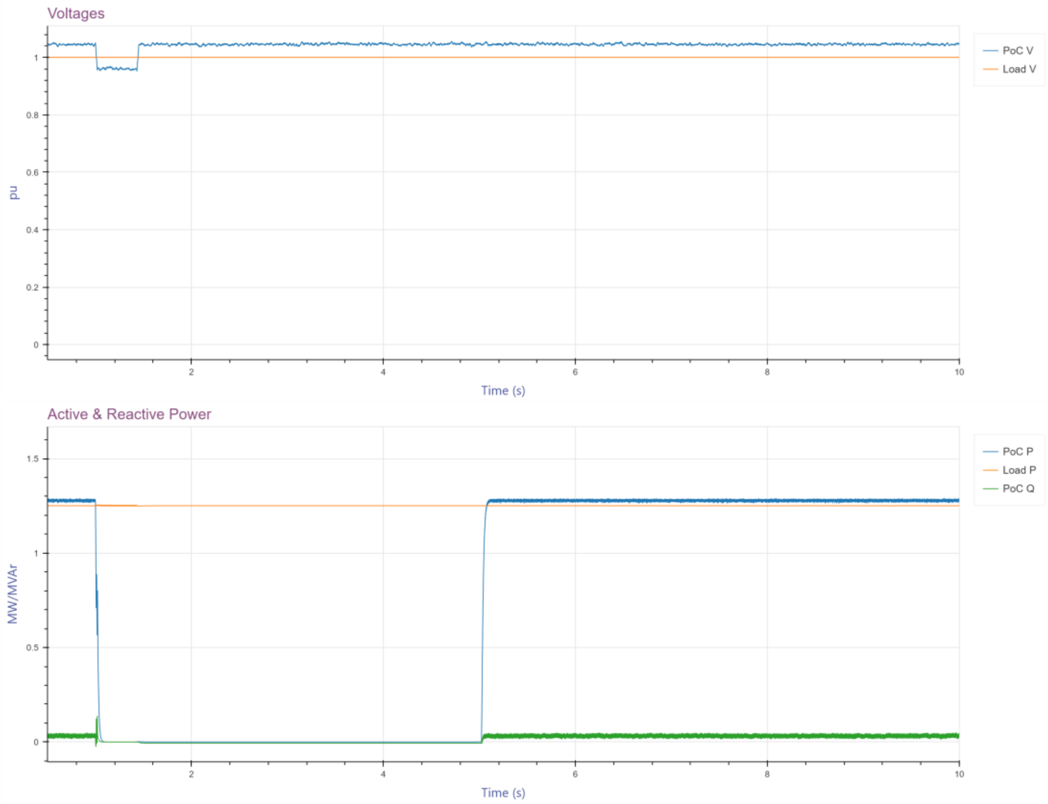


Figure 81 Shallow disturbance, voltage, P, Q on grid side and load side (illustrative of Archetype A).

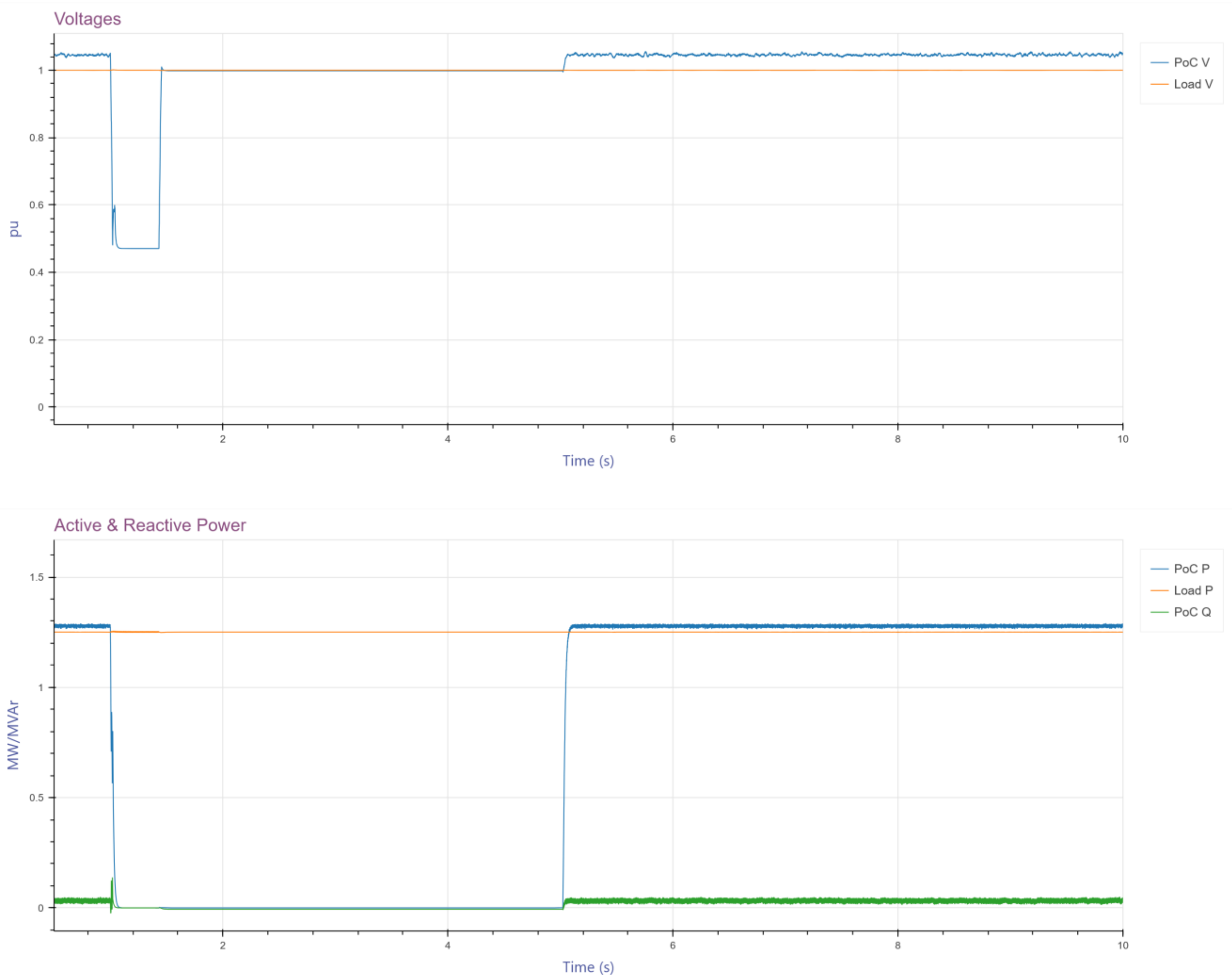
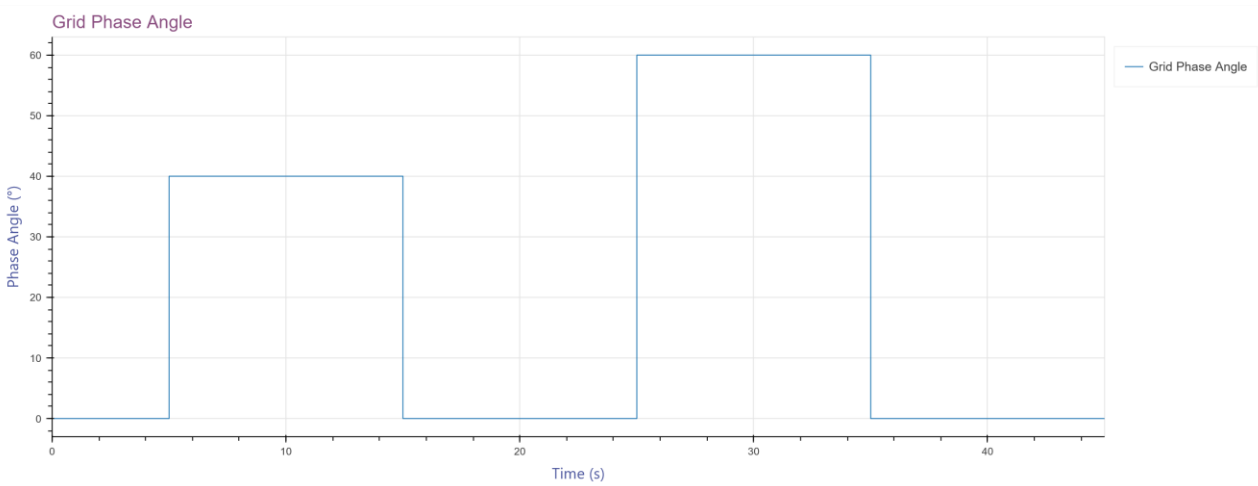


Figure 82 Deep disturbance triggering transfer, voltage, P, Q on grid side and load side (illustrative of Archetype B).



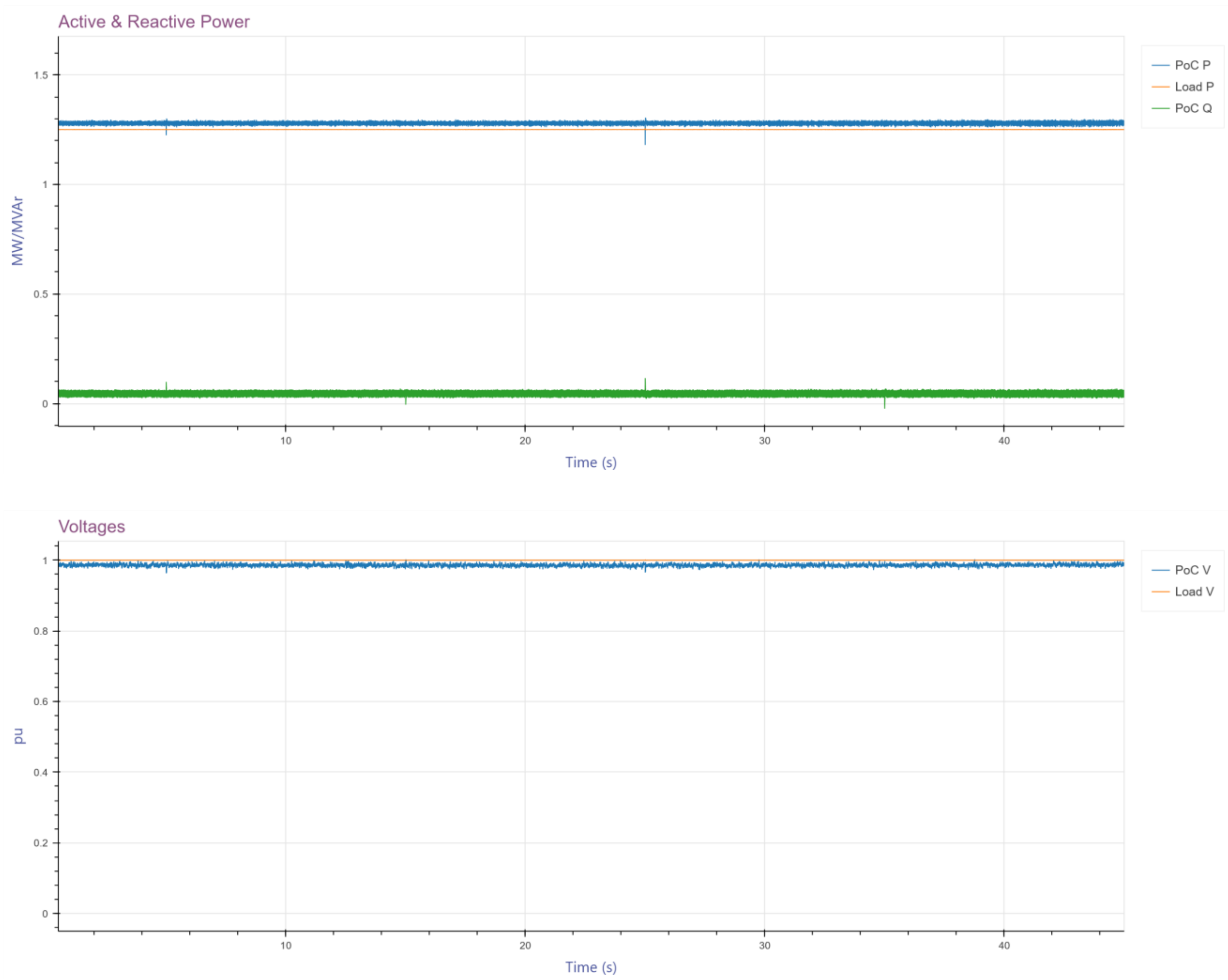


Figure 83 Phase-angle-jump profile and response, voltage, P, Q on grid side and load side (illustrative of Archetype C).

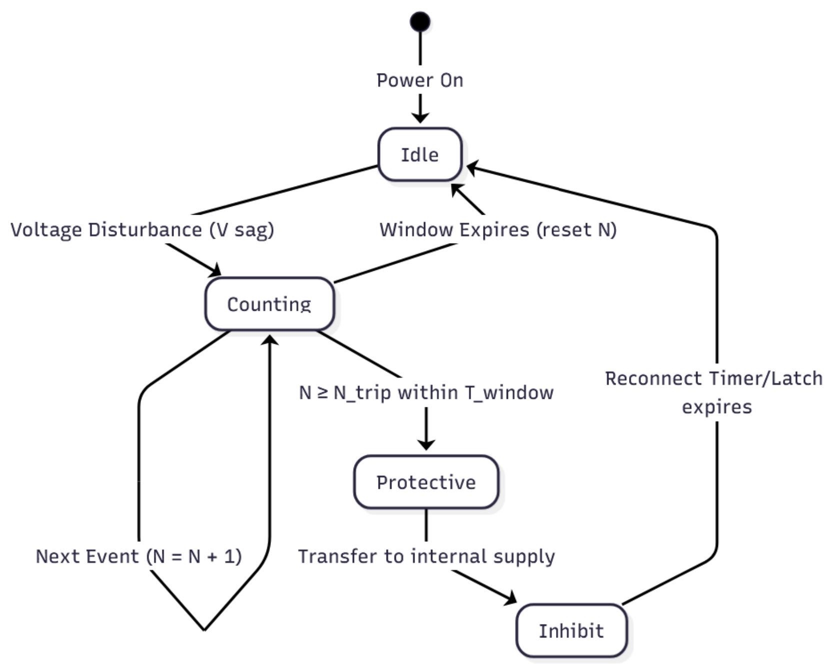


Figure 84 (conceptual): Disturbance counter window and transfer decision logic (illustrative of Archetype D).

7.5.3 Behaviour library and mapping to system relevance and modelling features

Table 30 consolidates key behaviours, their observable signatures, typical internal drivers, system relevance, and modelling implications. It deliberately separates behaviours that are often conflated, for example unbalance sensitivity versus phase-angle jump sensitivity and forced oscillations versus general control interactions.

Table 30 Performance mapping of key IBL behaviours

Functional behaviour	Typical observable signature at connection point	Common drivers or dominant modules	Why it matters in system studies	Modelling implication (what needs to be representable)
Fault ride-through and transient tolerance (incl. momentary cessation)	Connected ride-through, temporary power reduction, or cessation behaviour with time dependence	Grid-facing converters, supervisory logic	Contingency size, voltage recovery, credible disturbance magnitude	Time-dependent logic, not only thresholds; state-dependent response modes
Current-limited near-constant power response under voltage depressions	P approximately maintained while I increases until limit, then P reduces; Q may change	Rectifier or VSI limits, DC-link constraints	Can deepen voltage depressions; change recovery trajectory in weak areas	Current limiters; P/Q limiting; DC-link coupling proxy; correct timing of transitions
Conditional transfer to internal supply and return to grid	Rapid reduction of grid-supplied P, followed by staged return and recharge effects	UPS transfer logic, storage, supervisory logic	Can create large net load steps or ramps, including “second event” during recovery	Explicit transfer logic with timers and counters; segmentation (critical vs non-critical); return-to-grid criteria
Successive disturbance tolerance and disturbance-counting logic	Different response for first versus subsequent disturbances within a time window; transfer decision depends on event count and elapsed time	Supervisory logic, timers, counters, latches, transfer inhibit logic	Reclosing and repeated disturbances; coincidence risk; restoration sequencing	Explicit timer and counter state machine; latches and inhibits; do not model as simple threshold tripping
Diversity and coordination across multiple sites	Non-uniform timing, partial transfer, staggered responses across facilities	Site-level settings, supervisory coordination, differing designs	Coincidence risk in converter-dense or weak areas; aggregation uncertainty	Represent diversity, prioritisation and partial transfer options; avoid deterministic bulk tripping
Reconnection dynamics and recovery trajectories	Delayed reconnection, ramps, recharge transients, auxiliary restart coupling	Supervisory logic, storage recharge, cooling plant	Recovery can stress system more than initiating fault; secondary dips	Staged reconnection; ramp limits; recharge representation; restart sequencing
Load pick-up and restart behaviour (auxiliaries and process)	Inrush, staged restart, delayed load pick-up; possible Q swings	Motors and VFDs, building management, restart logic	Drives post-fault voltage recovery risk and reactive stress	Restart sequencing; dynamic auxiliaries where material; coupling to reconnection logic
Fault-induced delayed voltage recovery (FIDVR), where applicable	Extended post-fault voltage depression; elevated Q demand	Motor-heavy auxiliaries, compressor loads	Voltage recovery margin; potential repeated stress and protection actions	Motor and auxiliary representation when present and material; avoid assuming purely static recovery
Sensitivity to unbalanced conditions	Negative-sequence sensitivity; possible	Converter controls and protection, synchronisation	Power quality; local stability; nuisance transfer risk	Sequence-aware modelling; unbalance logic; relevant limits

Functional behaviour	Typical observable signature at connection point	Common drivers or dominant modules	Why it matters in system studies	Modelling implication (what needs to be representable)
	nuisance trips; asymmetric current			
Phase-angle jump sensitivity	P and Q deviations or mode changes during rapid angle steps	PLL-based synchronisation in rectifier or inverter stages	Weak-grid stability; reclosing behaviour; conditional transfer risk	Explicit phase-angle disturbance response envelope and timing
DC voltage and current stability	DC-link sag, saturation, collapse; slow recovery	DC-link, DC/DC regulation, energy constraints	Converter stability; delayed recovery; mode transitions	Represent DC states (at least aggregated); limits; interactions with current limiting
Instantaneous AC overvoltage and overcurrent sensitivity	Fast limiting, saturation, potential rapid disconnection	Protection, converter limits	Equipment stress; post-fault recovery impacts	Fast limit and protection logic; saturation behaviour, especially for EMT benchmarking
Reactive power dynamics (including surges)	Q transients during fault and recovery; possible step changes	Converter modes, limits, auxiliary restart	Local voltage excursions; recovery support or drag	Dynamic Q capability; limits; mode dependence (grid-connected versus backup supply)
Control-driven oscillations and interaction resonances (low-frequency)	Sustained oscillations (low frequency) or narrow-band control-induced oscillations; harmonic amplification	Converter controls, network resonance, filters	Small-signal and transient stability; power quality risk	Bandwidth and delay awareness; resonance screening; EMT where resonance is material
Forced oscillations and pulsing demand	Periodic power variation (up to a few Hz), or higher-frequency control-induced oscillations	Workload cycling, mis-tuned controls, firmware defects	Can excite natural modes and propagate; hard to diagnose post-commissioning	Include credible variability and oscillation envelopes; consider monitoring and EMT-based investigation when indicated
Control interactions (IBL–IBL, IBL–IBR) and low system strength sensitivity	Local instability; oscillatory recovery; interaction with nearby converter plant	Converter controls, weak voltage waveform stiffness	Higher risk in weak areas with high converter density	Control-structure-aware abstraction; impedance sensitivity; selective EMT benchmarking for fast phenomena
Low system strength sensitivity	Apparent change in incremental P–V and Q–V sensitivity; altered fault current shape or magnitude during disturbances; effective reduction or increase in “voltage stiffness” seen by the network	M1 (grid-facing AC–DC stage), M2 (DC link), M10 (protection/limits), sometimes M9 (supervisory logic)	Changes local voltage recovery and interaction risk; can alter effective strength margins and the stability of nearby converters, particularly during faults and restoration [54], [52]	Represent the load’s incremental behaviour under disturbed conditions (current limiting, constant-power tendency, DC-link constraints, mode dependence) so the model reproduces the same connection-point sensitivity that drives system strength outcomes
Frequency interaction and UFLS implications	Large coincident load steps or ramps; increased AGC duty; RoCoF sensitivity	Transfer and recovery, workload cycling, price response	Contingency sizing and operational security; reserve requirements [20]	Represent credible ramp envelopes, coincidence scenarios, and timing; do not assume smooth aggregate behaviour
Power quality interaction (harmonics, resonance, ferroresonance)	Harmonic distortion amplification; resonant conditions; unbalanced overvoltage risks	Network impedance, transformer and cable capacitance, converter emissions	Nuisance trips; equipment stress; slow diagnosis in service	Harmonic and resonance screening; EMT or harmonic-domain studies where elevated sensitivity is identified

The behaviours listed above become study-critical under conditions such as weak grid locations, high penetration of IBRs, large IBL size relative to local short-circuit strength, clustered or coincident IBL connections, and high converter density in close electrical proximity. The purpose of this activity is to provide a structured basis for determining which behaviours must be represented for a given study context, rather than to imply that all behaviours must be modelled at the highest level of detail in all cases.

7.5.4 When these behaviours become study-critical

Whether a behaviour needs explicit modelling depends on the study question and how materially the IBL can influence the surrounding network [45], [55]. Practical screening cues commonly used internationally include not only MW size, but also voltage sensitivity, system strength at the connection point, load composition (direct on line (DOL) versus power electronics), and the likelihood of interaction with nearby IBRs [55].

For example, a screening approach can consider criteria such as (i) whether voltage changes caused by the load are non-trivial, (ii) whether the feeder or local area is weak, and (iii) whether there is a cluster of medium-to-large power-electronic loads or competing IBR and IBL in the same electrically weak area [54], [52].

Separately, where multiple large sites are present, diversity and coordination of UPS behaviours becomes important, including staggered or prioritised transfers, and partial grid connection while supplying critical blocks from storage.

Diversity and uncertainty representation for aggregation studies

Where multiple medium-to-large IBL sites are present in the same electrically weak area, system outcomes can be driven as much by diversity and coincidence as by any single site's response [46], [51]. In these contexts, the dominant uncertainty is often the distribution of transfer and recovery timing across a fleet, rather than the exact steady-state demand of any single site. In practice, IBL response is often governed by supervisory settings and conditional logic, meaning that small variations in thresholds, timers, counter windows, ramp rates, and load segmentation can determine whether behaviour is staggered or coherent. Importantly, coincidence risk is driven not only by parameter ranges, but also by correlation across sites (for example common default settings, common firmware versions, or common engineering practices), which can produce coherent behaviour even when individual parameter uncertainty appears modest. Because these parameters may not be disclosed in detail, the framework should support study-relevant representation of diversity without requiring vendor-specific internal implementations.

For aggregation and hub-type studies (for example clustered data centres, multiple electrolysers, or mixed IBL fleets), three fit-for-purpose approaches are recommended, selected according to study objective and materiality:

Representative-site with bounded envelopes:
A single representative model is used, with envelope bounds applied to key timing and limiting parameters (for example transfer trigger thresholds, counter window duration, reconnection inhibit, recharge time constants, and ramp limits). This approach is suitable for early screening where the goal is to identify whether coincidence could matter, rather than to predict exact fleet timing.

Scenario ensemble (low-to-high coincidence cases):
A small set of discrete scenarios is defined to bracket credible fleet behaviour, for example high diversity (staggered transfer and reconnection), medium diversity (partial clustering), and low diversity (highly coherent behaviour). Scenarios are implemented by varying a small parameter set consistently across sites, rather than changing model structure. For transparency, studies should report the resulting distribution of key times and steps (for example transfer initiation time, return-to-grid time, and net MW/MVAr step magnitude), not only the underlying parameter values.

Stochastic diversity (Monte Carlo or sampled parameter sets):
Where coincidence risk is central to the study question, diversity is represented by sampling key supervisory and recovery parameters from defined distributions across the fleet, with the distribution bounds justified by available evidence (vendor statements, factory evidence, in-service disturbance replay, or conservative engineering judgement). Where coherence is plausible, sampling should include shared common-mode factors (for example a fleet-wide timer bias plus site-to-site scatter) rather than assuming independent parameters at each site.

To enable these approaches, a minimum **Diversity Parameter Set (DPS)** for fleet studies is a useful starting point. This set should be expressed as externally visible behavioural descriptors and mapped to the interface signals and retained states (primarily M9, M10, and where relevant M2–M3 and M8), including, where applicable:

- transfer thresholds and detection criteria;
- disturbance counter limits and window duration;
- reconnect inhibit timers and return-to-grid criteria;
- ramp-rate limits and staged restoration timing;
- energy buffer characteristics governing ride-through duration and recharge trajectory;
- critical versus non-critical block fractions and any load shedding priorities; and
- fleet segmentation and common-mode grouping assumptions (for example, site groups with common OEM/UPS type/firmware/configuration).

Table 31 provides an illustrative minimum DPS template for documenting these descriptors consistently across representative-site, scenario-ensemble, or stochastic diversity studies. It is not intended to prescribe specific settings or disclose internal vendor logic. Instead, it identifies the behavioural descriptors that should be recorded, bounded, or sampled to transparently represent diversity, correlation, and coincidence risk in system studies.

Table 31 Example minimum Diversity Parameter Set (DPS) template for fleet and hub studies

DPS element	Example descriptor to record	Typical modelling use	Primary interface mapping
Transfer trigger threshold	Voltage, phase-angle, unbalance, frequency, or DC-limit trigger used to initiate ride-through, momentary cessation, or transfer logic	Defines whether sites remain grid-connected, reduce demand, or transfer under a given disturbance	M1, M2, M9, M10
Detection or dwell time	Minimum duration for which the trigger condition must persist before action is taken	Distinguishes transient ride-through from sustained disturbance response	M9, M10

DPS element	Example descriptor to record	Typical modelling use	Primary interface mapping
Disturbance counter limit	Number of qualifying events allowed before transfer, blocking, or alternative recovery logic is triggered	Captures successive-fault tolerance and reclosing sensitivity	M9, M10
Counter window duration	Time window over which successive events are counted or reset	Determines whether repeated disturbances are treated independently or as a cumulative sequence	M9, M10
Transfer or cessation delay	Delay between trigger satisfaction and observable change in grid-side P/Q or current	Sets timing of load step, ramp, or momentary cessation at the connection point	M1, M5, M9, M10
Critical load fraction	Fraction of site load treated as critical or supplied through ride-through or internal supply path	Determines residual grid demand and transfer magnitude during internal-supply operation	M6, M9
Non-critical or shed-able fraction	Fraction of site load that can be curtailed, delayed, or restored in stages	Determines offloading magnitude and staged restoration profile	M7, M8, M9
Reconnect inhibit timer	Minimum time before return-to-grid is permitted after transfer, trip, or blocking	Prevents unrealistically immediate reconnection and supports restoration sequencing studies	M5, M9, M10
Return-to-grid criteria	Voltage, frequency, synchronisation, DC-state, or stability conditions required before reconnection	Determines when recovery can begin and whether sites return coherently or in stages	M2, M4, M5, M9
Active power ramp-rate limit	Maximum rate of grid-side MW restoration or recharge demand increase	Controls recovery trajectory and potential “second event” magnitude	M2, M3, M8, M9
Reactive power or current recovery limit	Limit or ramp applied to Q, current, or converter capability during recovery	Captures voltage recovery impacts and MVAr transients	M1, M8, M10
Energy buffer descriptor	Ride-through duration, usable stored energy, recharge time constant, or SOC recovery envelope	Represents storage-limited behaviour and recharge-driven recovery demand	M2, M3, M9
Auxiliary restart timing	Delay, sequencing, and ramp profile for cooling, pumps, compressors, or other balance-of-plant loads	Captures delayed load pick-up and post-fault recovery stress	M8, M9
Fleet segmentation	Grouping by site type, OEM family, UPS topology, firmware, configuration, or operational policy	Enables high-, medium-, and low-diversity scenario construction	M9, M10
Common-mode correlation factor	Shared timing bias, common threshold band, or common configuration assumption across a group	Represents coherent behaviour caused by common engineering settings or equipment families	Fleet-level DPS overlay
Site-to-site scatter	Distribution or bounded range around each fleet-group setting	Represents diversity across otherwise similar sites	Fleet-level DPS overlay

For practical studies, the DPS should be reported as either:

i. a bounded envelope for screening studies;

ii. a small scenario ensemble representing high, medium, and low coincidence cases; or

iii. a sampled parameter set with explicit common-mode factors where coincidence risk is central to the study question. In all cases, the study should report the resulting distribution of observable outcomes, including transfer initiation time, return-to-grid time, maximum MW/MVAr step, recovery ramp rate, and recharge duration.

In all cases, the study should report the resulting distribution of observable outcomes, including transfer initiation time, return-to-grid time, maximum MW/MVAr step, recovery ramp rate, and recharge duration.

These parameters should be treated as externally visible behavioural descriptors, not as disclosures of internal design, and they should be sufficient to reproduce plausible ranges of connection-point response timing and magnitude.

7.5.5 Practical implications for model choice

Some behaviours of interest, including certain mode-transfer actions, can occur on millisecond timescales and can be difficult to represent credibly without EMT benchmarking [53]. Conversely, slower recovery processes can often be captured in PDT abstractions, provided timing, thresholds, and state dependence are parameterised consistently. (Implementation guidance on how this mapping flows into module interfaces and PDT versus EMT structure is handled in Sections 7.6.6 onward.)

7.6 Activity 3 – Modular interface specification and model structure

This activity defines a modular, technology-neutral interface specification and associated model structure for IBLs that supports consistent representation across EMT and PDT simulation environments. The intent is to enable scalable, fit-for-purpose modelling by decomposing complex facilities into a set of functional modules with clearly defined interfaces, while preserving flexibility in internal implementation and level of detail.

Detailed investigations of large IBLs indicate that a small number of subsystems and control layers often dominate externally observable behaviour during disturbances and recovery. In particular, supervisory logic, DC-link dynamics, and grid-facing converter limits frequently have a more decisive influence on connection-point response than downstream process demand characteristics. The interface specification therefore treats supervisory and mode logic as a first-class modelling element, rather than embedding it implicitly within static load behaviour, so that conditional transfer, reconnection sequencing, and recovery trajectories can be represented explicitly.

7.6.1 Module inventory and modular decomposition

The proposed approach recognises that not all subsystems need to be represented explicitly in every study. Instead, it provides a structured framework in which modelling granularity can be selected based on study objectives, system conditions, and the materiality of specific behaviours identified in Activity 2. The facility is decomposed into functional subsystems, recognising that different subsystems govern different externally observable behaviours.

Table 32 lists a recommended “module inventory” that is applicable across major IBL classes. Not every facility will include every module, and not every module must be modelled with high fidelity.

The purpose of the inventory is to standardise how modelling elements are named, bounded, and interfaced.

Table 32 Recommended module inventory for IBL model structures (technology-neutral)

Module	What it represents	What it primarily influences at the connection point	Typical internal states to retain (as needed)	Notes on PDT vs EMT implementation
M0 Grid interface and site transformer	Transformer, earthing, short-circuit impedance, and tap behaviour (if relevant)	V–I relationship at the modelling boundary, including the voltage seen by the facility during disturbances and the impedance path for current drawn, with saturation effects where material	Magnetising branch state (if EMT), tap position (if switched)	PDT often sufficient; EMT if transformer saturation or fast overvoltage phenomena are material
M1 Grid-facing AC–DC stage	Rectifier or active front end, including synchronisation	Current limiting, near-constant power tendency, P/Q response during voltage disturbances, unbalance sensitivity	Synchronisation state (e.g., PLL), current limit flags, control mode flag [44] [2]	PDT abstraction must preserve limiting and timing; EMT used to benchmark fast limit and unbalance behaviour
M2 DC link or DC bus	Aggregate DC energy storage, capacitance, DC impedance	Transition behaviour under voltage depressions, ride-through duration, recovery trajectory	DC voltage, equivalent energy state, DC current limits	PDT can retain 1–2 aggregated states; EMT when DC dynamics and protection interactions drive outcomes
M3 DC/DC stages (optional)	DC regulation, battery interface, electrolyser stack interface, charger stages	DC stability, power limiting, recovery ramps, recharge behaviour	Converter state and limit flags, ramp-rate state	Often abstracted in PDT via limits and time constants; EMT for detailed interactions
M4 DC–AC inverter stage (optional)	UPS inverter supplying internal AC, inverter-fed internal buses	Mode transitions, bypass interaction, internal AC stability that affects grid-side P/Q	Mode flag (inverter, bypass), synchronisation state (if applicable)	PDT abstraction usually envelope-based; EMT for transfer transients and fast protection
M5 Static bypass and transfer equipment (optional)	UPS bypass path, STS logic, feeder transfer	Rapid changes in grid-supplied P/Q, transfer timing and thresholds	Transfer state, timers, counters	Often needs explicit state machine even in PDT; EMT for transient switching effects where needed
M6 Internal critical load block	“Must-ride” IT/process demand segment	Sets baseline MW demand, may influence recovery ramps	Recovery ramp state, block enable flag	PDT generally adequate, unless fast pulsing demand needs EMT benchmarking
M7 Internal non-critical / shed-able load block	Curtailable segment, staged load shedding	Step/ramp changes during events, reconnection diversity	Shedding state, reconnection timers	Represented as segmented blocks; diversity can be parameterised statistically
M8 Auxiliary and balance-of-plant	Cooling plant, pumps, compressors, VFD-fed auxiliaries	Recovery phase dynamics, delayed load pick-up, possible Q swings	Restart sequencing states, motor/VFD dynamic states (if material)	PDT often adequate with staged restart logic; EMT where converter interactions or harmonics are material
M9 Supervisory and mode logic (cross-cutting)	Facility state machine coordinating transfer, reconnection, priorities	Conditional behaviour, counters, sequencing, “second event” risk	Mode, timers, counters, blocking and inhibit flags	Must be explicit in both PDT and EMT where mode transitions are study-relevant

Module	What it represents	What it primarily influences at the connection point	Typical internal states to retain (as needed)	Notes on PDT vs EMT implementation
M10 Protection and limit logic (cross-cutting)	Fast V/I limits, DC protection, blocking, ride-through modes	Timing of limiting and disconnection, momentary cessation, reconnection inhibits	Limit flags, trip latches, cooldown timers	PDT should reflect timing and latches; EMT benchmarks fast activation and saturation behaviour
M11 Power quality and harmonic source (optional)	Emission representation for harmonic/resonance studies	Harmonic current injection, resonance amplification	Control delay/bandwidth parameters (as needed)	Usually separate study path; EMT or harmonic domain tools where required

7.6.2 Component-based modular structure

Interfaces are defined so that externally observable behaviour at the connection point is the primary validation target, while internal design freedom is preserved. The interface specification separates: (i) external interface quantities (what the power system "sees"), and (ii) internal coordination signals (what modules exchange to realise state-dependent behaviour).

Table 33 Interface definition principles (what the specification constrains)

Principle	What it means in practice	What it enables
Clear separation of subsystems	Modules are defined by function, with explicit boundaries and minimal hidden coupling	Modular assembly, reuse across technologies, targeted refinement
Observable behaviour as the validation target	Connection-point quantities are the reference, including P, Q, V, I and timing	Technology-neutral validation and benchmarking
Internal design freedom preserved	Interfaces specify inputs, outputs, limits, states, and timing, not internal control topology	OEM-neutral modelling, reduced need for sensitive design disclosure
Explicit state dependence when material	Transfer logic, latches, cooldowns, counters and staged recovery are represented explicitly	Credible disturbance response and recovery in studies
Consistent parameterisation across PDT and EMT	Limits, delays, ramps and recovery envelopes map coherently across domains	Cross-domain coherence, EMT-to-PDT translation and comparability
Proportionate fidelity	Detail is increased only where it changes study conclusions	Scalable studies without unnecessary complexity

This modular decomposition allows consistent mapping between EMT and PDT representations. Where appropriate, EMT models can be used to inform the parameterisation, limits, and time constants of PDT abstractions.

7.6.3 Standard interface signals and state variables

A practical interface specification needs a minimum set of signals that each module exposes, so that (i) different vendors can be represented consistently, and (ii) PDT abstractions can be benchmarked against EMT behaviour using the same "observable envelope" concept.

Table 34 Minimum interface signals and states for modular IBL implementations

Category	Signal / state (rewritten, original in brackets)	Description	Required for PDT	Required for EMT
Connection-point observables	V_term (V), I_term (I)	Terminal voltage and current at the modelling boundary; three-	Yes	Yes

Category	Signal / state (rewritten, original in brackets)	Description	Required for PDT	Required for EMT
		phase waveforms or phasors as appropriate		
Connection-point observables	P_term, Q_term (P, Q)	Active and reactive power at the modelling boundary	Yes	Yes
Disturbance observables	V_pos_seq, V_neg_seq (Sequence quantities V1/V2 or equivalent)	Unbalance characterisation where relevant	If unbalance is material	Yes, where unbalance is studied
Mode and event flags	operating_mode (mode_state)	Enumerated facility operating mode, for example grid-connected, momentary cessation, on internal supply, recovery	Yes, when conditional behaviour matters	Yes
Mode and event flags	transfer_to_internal_flag (transfer_active)	Indicates transfer to internal supply is active (initiated or completed, depending on implementation)	As applicable	As applicable
Mode and event flags	bypass_mode_flag (bypass_active)	Indicates bypass path is in use, where applicable	As applicable	As applicable
Limits and latches	ac_current_limit_flag (current_limit_active)	Indicates AC-side current limiting is active, used to align limiting timing between PDT and EMT representations	Yes when current limiting is material	Yes
Limits and latches	dc_limit_flag (dc_limit_active)	Indicates DC-side limiting is active (may correspond to DC voltage, DC current, or DC power limiting depending on technology)	Yes when current limiting is material	Yes
Limits and latches	trip_latch_state (trip_latch)	Latched trip or blocking state (persists until reset logic clears it)	Yes where reconnection matters	Yes
Limits and latches	reconnect_inhibit_timer (reconnect_inhibit)	Reconnection inhibit timer (or remaining inhibit time), preventing immediate return-to-grid	Yes where reconnection matters	Yes
Energy state	V_dc (Vdc)	Aggregated DC voltage (or equivalent DC state variable used as the energy proxy)	Often (aggregated)	Yes (detailed as needed)
Energy state	SOC_store (SOC, if applicable)	Energy buffer state of charge, where an explicit storage element exists	Often (aggregated)	Yes (detailed as needed)
Recovery behaviour	power_ramp_limit (ramp_rate_limit)	Ramp limit governing return-to-grid and restoration (typically applied to active power, optionally reactive power)	Yes where recovery is material	Yes
Recovery behaviour	recovery_state_timer (recovery_timer)	Timer governing restoration sequencing, return-to-grid dwell, or staged pickup logic	Yes where recovery is material	Yes
Segmentation	critical_load_fraction (critical_block_fraction)	Fraction of load treated as critical or “must-ride” for segmentation studies	Recommended for aggregation studies	Optional, depending on model detail

Category	Signal / state (rewritten, original in brackets)	Description	Required for PDT	Required for EMT
Segmentation	shedable_load_fraction (shed_fraction)	Fraction of load available for shedding or non-critical restoration staging	Recommended for aggregation studies	Optional, depending on model detail
Optional, power quality	harmonic_emission_enable_flag (harmonic_source_enable)	Enables harmonic or emission representation for dedicated harmonic or resonance studies	No	As required
Optional, power quality	harmonic_emission_parameters (emission_params)	Parameter set defining emission characteristics for harmonic or resonance studies	No	As required

7.6.4 Supervisory and mode logic representation

Where conditional behaviour is material, supervisory logic should be represented as an explicit state machine with timers, counters, and prioritisation of internal load blocks. This is critical for representing: (i) tolerance to successive disturbances, (ii) conditional transfer decisions, and (iii) coherent or staged recovery that can create a material second event.

Table 35 Illustrative supervisory state machine (technology-neutral)

State	Description	Typical entry triggers	Typical outputs to grid-facing modules	Typical exit conditions
S0 Normal grid-connected	Facility operating on grid	Normal conditions	P/Q follow demand within limits	Disturbance detected, limit reached, or transfer criteria met
S1 Disturbance ride-through	Remains grid-connected, may reduce power or enter momentary cessation	Voltage depression, phase-angle step, unbalance (as applicable)	Limiting flags, possible temporary P reduction, mode flags	Disturbance clears, or counters/thresholds trigger transfer
S2 Transfer initiation	Decision to transfer to internal supply	Timer/counter logic satisfied, protection criteria met	transfer_active asserted, begin load segmentation	Transfer completes, or abort criteria met
S3 On internal supply	Grid-supplied P reduced, critical blocks maintained internally	Transfer complete	Grid-side P reduced to residual or zero, bypass behaviour as applicable	Return-to-grid criteria satisfied
S4 Return-to-grid synchronisation	Preparation to reconnect and resupply	Reconnect inhibit elapsed, voltage stable	Controlled ramp and synchronisation flags	Reconnection completed
S5 Recovery and recharge	Restoration of non-critical blocks, recharge of storage, auxiliary restart	After reconnection	Ramp limits active, staged pick-up states active	Recovery complete, return to S0

Figure 85 provides an illustrative supervisory state sequence that captures the minimum set of mode transitions typically required to represent disturbance handling and supply transfer behaviour in a technology-neutral way. The diagram is intentionally generic, but it highlights that a credible model must represent not only steady operating modes, but also the transition logic and timing between them. In particular, the sequence from S0 (Normal grid-connected) through S1 (Disturbance ride-through) to S2 (Transfer initiation) and S3 (On internal supply) clarifies that transfer decisions are usually driven by explicit triggers, counters, and time windows, rather than by a single threshold. The subsequent transition to S4 (Return-to-grid synchronisation) and S5 (Recovery and recharge) reflects the practical reality that reconnection is normally conditional on a defined set of return criteria, and that recovery often includes latching, inhibit timers, and staged restoration of capability.

For modelling purposes, the key requirement is that the state transitions preserve the externally observable behaviour at the point of connection, including the timing of transfer, any temporary limits or prioritisation applied during internal supply, and the conditions under which reconnection is permitted. These elements materially influence voltage and current behaviour during disturbances and switching events, and therefore they must be represented consistently across both EMT benchmarking models and any corresponding PDT abstractions.

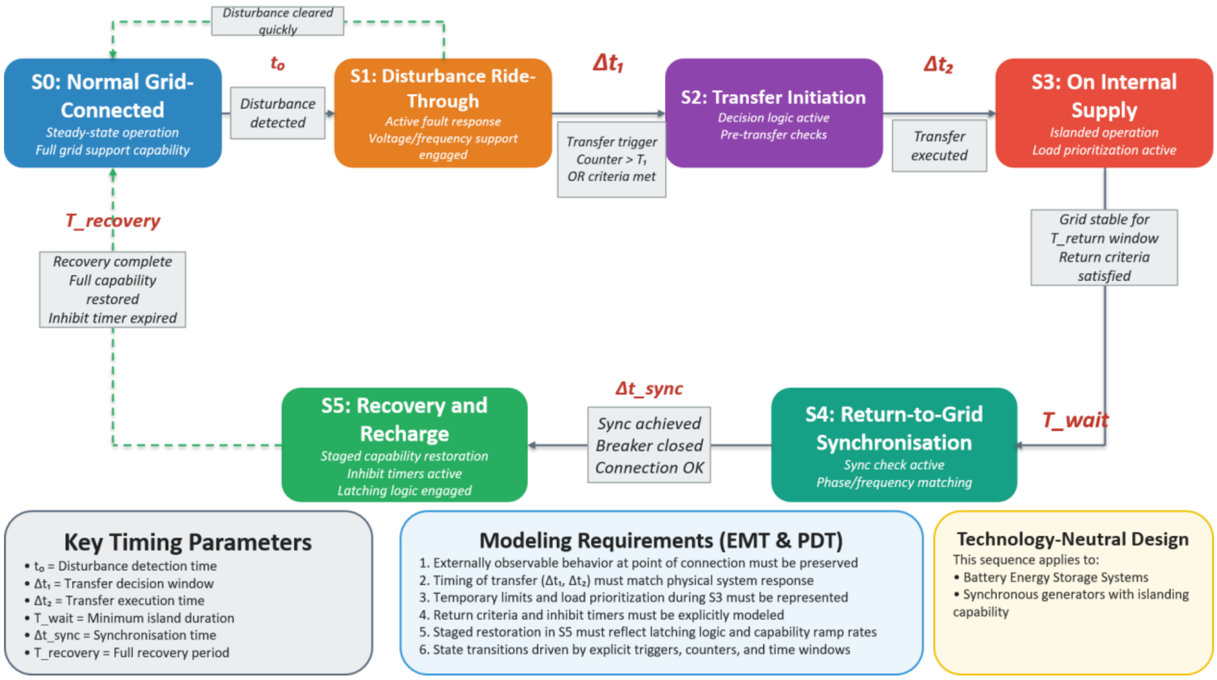


Figure 85 Illustrative supervisory state sequence for disturbance ride-through, supply transfer, and return-to-grid recovery (technology-neutral).

7.6.5 Mapping from behaviours to modules and minimum modelling features

To keep the interface specification actionable, behaviours identified should map to: (i) the dominant modules, and (ii) the minimum features that must be representable, irrespective of whether the final implementation is EMT or PDT.

Table 36 Behaviour-to-module mapping and minimum representation (study-focused, non-prescriptive)

Behaviour	Dominant modules	Minimum features that must be representable	PDT implementation note	EMT implementation note
Voltage disturbance ride-through, including momentary cessation	M1, M2, M9, M10	Time dependence, limiting, mode flags, latches	Envelope matching with correct transition timing	Benchmarks fast limiting and protection activation
Phase-angle jump response	M1, M9, M10	Explicit phase-angle disturbance response envelope, timer/counter dependence if used	Represent response as a bounded P/Q deviation with triggers	Capture synchronisation dynamics where relevant

Behaviour	Dominant modules	Minimum features that must be representable	PDT implementation note	EMT implementation note
Unbalance sensitivity	M1, M10	Sequence-aware behaviour, negative-sequence dependent logic	Include sequence proxy where material	Explicit three-phase modelling as required
Current-limited near-constant power behaviour	M1, M2, M10	Current limiter, P reduction beyond limit, correct timing and saturation	Must include limiter and DC coupling proxy	Confirms limiter dynamics, saturation and interactions
Transfer to internal supply and return-to-grid	M4, M5, M2, M9	State machine, segmentation (critical vs non-critical), latches and inhibits	Must be explicit, do not represent as binary trip only	Captures transfer transient detail where needed
Recovery and recharge, auxiliary restart coupling	M2, M3, M8, M9	Staged reconnection, ramp limits, recharge trajectories, restart sequencing	Often well represented with timers and ramps	Used where fast interactions or harmonics matter
Harmonics and resonance interaction	M11 plus network context	Emission characterisation and sensitivity to impedance	Usually separate study workflow	EMT or harmonic-domain study depending on question

7.6.6 PDT and EMT model structure guidance

The framework supports complementary use of PDT and EMT models [50], [46]. EMT is typically used to benchmark fast or interaction-sensitive phenomena and to identify limits, delays, transitions, and latches. PDT is then parameterised to reproduce the same connection-point response envelopes over study-relevant timeframes.

In practice, EMT adds the most value when the study question involves phenomena above the bandwidth where phasor transient stability models are trusted (often a few hertz), or where detailed power-electronic control interactions and resonances need to be assessed. For example, time-series load profiles can be analysed in the frequency domain to identify whether material excitation exists in higher-frequency bands, and EMT studies are then targeted to risks in roughly the 5–60 Hz range, including control-driven modes, network resonances, and torsional interactions.

Table 37 Recommended modelling approach by simulation domain

Aspect	PDT models	EMT models
Primary purpose	Wide-area screening and planning studies	Local detailed studies, benchmarking, interaction assessment [53]
Time resolution	ms–s	µs–ms
Converter representation	Averaged, envelope-based; preserves limits, delays, latches	Switching or detailed averaged; captures fast dynamics and interactions
DC dynamics	Aggregated states, proxy limits	Explicit DC states and protection interactions
Supervisory logic	Explicit state machine where conditional behaviour matters	Explicit state machine, plus fast limit and transfer details as needed
Validation target	Connection-point envelopes for V, I, P, Q, including transition timing	Waveforms plus envelopes, used to inform PDT abstraction

7.6.7 Model validation, benchmarking, and evidence hierarchy

Model validation for inverter-based loads is necessarily more pragmatic than for inverter-based resources [55]. Many large data centres are not connected at transmission level, and even where they are, commissioning and model validation tests are typically not executed with the same breadth, repeatability, or formalised expectations that are common for IBRs. As a result, validation evidence for IBLs is often assembled from a combination of factory evidence, targeted functional checks, and in-service disturbance observations, rather than from a standardised commissioning test suite.

Validation should therefore be framed as an evidence hierarchy and a confidence grading, proportionate to the study purpose and the materiality of the IBL in the local network. A practical hierarchy is as follows:

- **In-service disturbance replay and envelope matching** at the connection point, using event records where available, including voltage sags, phase-angle disturbances, and successive event sequences.
- **Factory and integration evidence**, such as functional transfer demonstrations, current limiting behaviour, DC-link response, and protection or limit latching behaviour, supported by test waveforms where available.
- **Model reasonableness checks** against known physical constraints and credible operating envelopes (limits, time constants, ride-through logic, recharge behaviour), where direct test evidence is limited.

Hardware-in-the-loop (HIL) can be valuable in early stages to confirm control logic, limit behaviour, and event sequencing prior to site energisation, particularly when an EMT model is being used to parameterise a PDT abstraction [53]. However, it is recognised that HIL capability is not widely available across UPS OEMs, even though it is common practice for IBR and HVDC vendors. Where HIL is not available, equivalent confidence building can be achieved through a combination of offline EMT benchmarking, controller-in-the-loop where feasible, factory waveform evidence, and conservative but technically plausible envelope bounds for limits, latches, and recovery trajectories.

Recommended deliverable artefact: a one-page "Validation and benchmarking plan" per major IBL type, including (i) the intended evidence sources, (ii) the events to be benchmarked, (iii) the confidence grade assigned to each behaviour group (ride-through, current limiting, transfer and recovery, unbalance and phase-angle response), and (iv) any residual uncertainty assumptions carried into system studies.

Model lifecycle and change control: Because IBL behaviour can change materially with configuration and implementation details, model validity should be treated as conditional on the as-built configuration and settings [45]. Re-validation, or at least a targeted confidence review against the evidence hierarchy, should be triggered by material changes such as firmware upgrades, protection or transfer setting changes, UPS topology changes (including redundancy configuration changes), additions of major internal load blocks, changes to auxiliary plant control sequencing (notably cooling restart and ramp logic), changes in energy storage characteristics, or staged expansion that alters the ratio of critical to non-critical load. Where such changes occur and evidence is limited, studies should adopt conservative envelope bounds and document the residual uncertainty explicitly.

7.6.8 Modelling granularity guidance

Modelling granularity is selected using engineering judgement rather than fixed thresholds. The intent is to match model detail to the phenomena that can influence study conclusions, recognising that IBLs can exhibit fast, control-driven behaviours during disturbances and slower, state-dependent recovery behaviours that may be material at system level.

Table 38 Recommended modelling granularity (non-prescriptive)

Factor	Low granularity	Medium granularity	High granularity
Load size relative to local network	Electrically small	Large regional load	System-significant
Network conditions	Strong	Moderate	Weak or converter-dense
Technology complexity	Simple rectifier-dominated	UPS or multi-stage conversion	Multi-stage with conditional transfer and recovery complexity
Study objective	Screening	Planning, credible envelopes	Detailed interaction and event sequencing
Recommended domain	PDT	PDT with selective EMT benchmarking	EMT (with PDT used for wider-area context as needed)

7.6.9 Conceptual modular interface structure

The modular interface structure can be represented conceptually as:

Grid
→ M0 Grid interface and transformer
→ M1 AC–DC stage
→ M2 DC link / DC bus
→ (M3 DC/DC, optional)
→ (M4 inverter and M5 bypass/transfer, optional)
→ M6–M7 internal load blocks (critical, non-critical)
→ M8 auxiliaries and balance-of-plant

M9 supervisory and mode logic and M10 protection and limit logic operate across modules, coordinating operating states, conditional transfer, reconnection, and recovery.

7.6.10 Deliverables alignment (Task 3)

The outputs of Task 3 are structured to translate the technology characterisation, performance mapping, and modular interface specification into practical artefacts that can be applied consistently across studies and stakeholder contexts.

In addition to the narrative report content, the following concrete artefacts are recommended to make the interface specification directly usable:

- Module interface template: a standard one-page specification per module (inputs, outputs, states, limits, timers, counters).
- Behaviour-to-feature checklist: a checklist keyed to Table 36, used to justify model granularity and domain selection.
- PDT abstraction recipe: guidance for “envelope matching” against EMT benchmarks for selected events (voltage sag, phase-angle step, successive disturbance sequence, recovery and recharge).

- Illustrative state machine library: a small library of generic supervisory logic patterns (ride-through only, transfer with counters, staged recovery), parameterised rather than hard-coded.

8 Future work recommendations

Based on the research work carried out in Stage 5 of Topic 1, the following outlines key areas of research which would further increase understanding of IBR control design, its impact on overall system security and reliability, and enhance the knowledge base of IBL and IBR interactions.

- Validate model performance under high IBR-penetration or similar conditions to verify accuracy and applicability of research recommendations, through the following two approaches [New research topic]:
  - Protection relay bench testing: Feed high-resolution waveforms from the existing modelling response into physical relay equipment and assess the relay performance.
  - Validation through field measurements: Use high-resolution field measurements from network protection operation as an input to simulation models to assess and verify their accuracy.
- Integration of relevant protection relay models into system studies [Alignment with Major Task 4: Protection and Reliability of Topic 1 (Inverter Design)]:
  - Develop and incorporate transmission protection relays models into real-world system studies (at least for IBR rich areas). Model relevant aspects of operating logic of protective relays, including their dynamic response to varying fault current magnitude, phase angle and impedance, harmonics and any filtering used.
  - Use developed models to identify potential transmission relay mis-operation and suggest remediation measures.
- Dedicated screening methods for IBL [Alignment with Major Task 5: Trending Topics of Topic 1 (Inverter Design) and Topic 2 (Stability Tools and Methods)
  - Develop a screening method, tailored specifically for IBLs, to select the minimum modelling detail needed, rather than borrowing screening approaches used for IBRs.
  - Use the screening outcome to assign PDT versus EMT studies and an appropriate aggregation level.
- IBR and IBL Interaction Studies [Alignment with Major Task 5: Trending Topics of Topic 1 (Inverter Design)]:
  - Explore combined dynamics of IBRs and IBLs under weak-grid conditions.
  - Assess implications for stability and protection coordination.
  - Determine what changes, if any, are needed to commonly used stability assessment methodologies and tools for IBR-only scenarios.

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