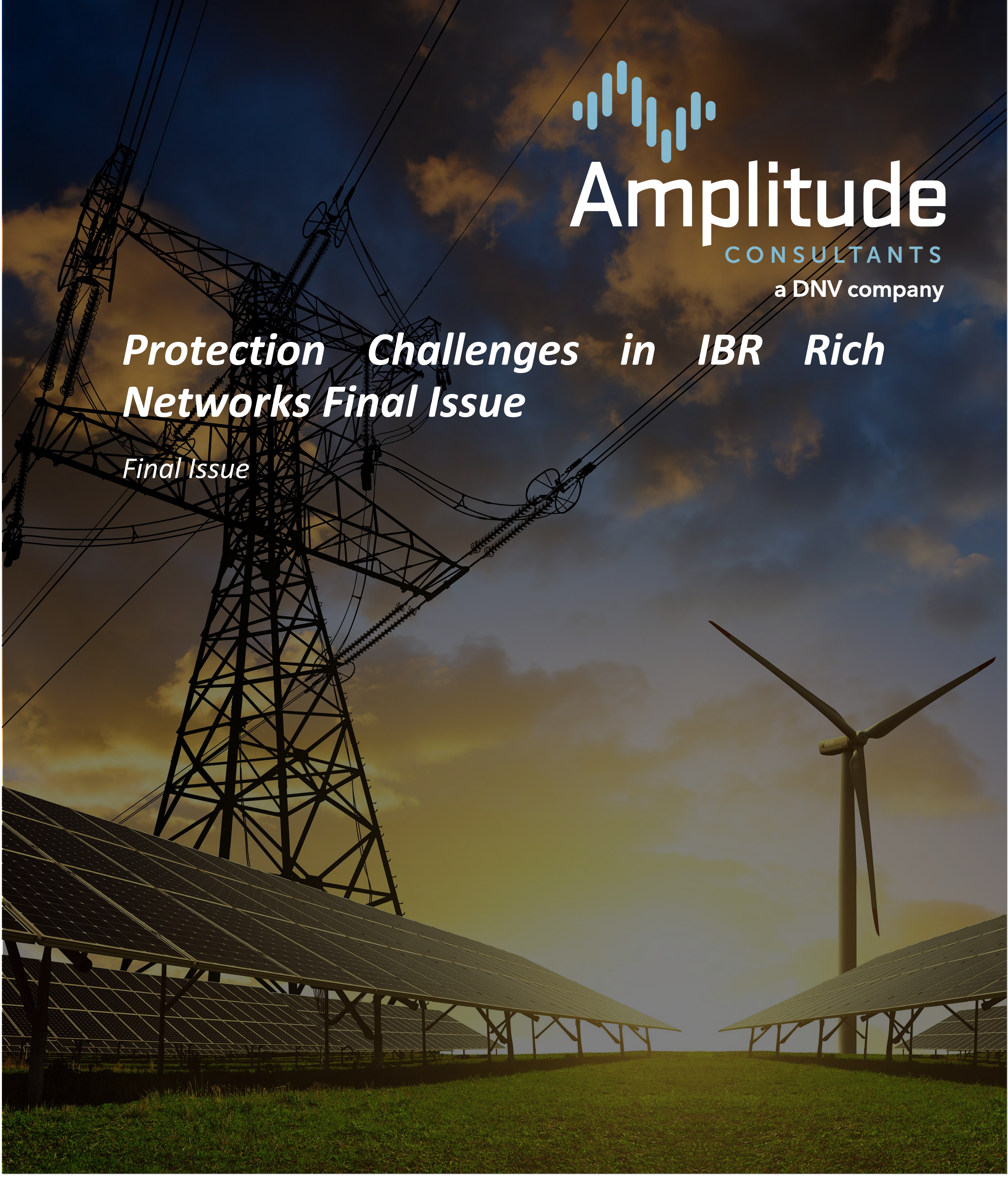


Amplitude CONSULTANTS a DNV company

Protection Challenges in IBR Rich Networks Final Issue

Final Issue

Amplitude Document Number:
PAU0503-REPT-002

Date of Issue:
3 July 2026

Revision:
REV 1

CSIRO Australia's National Science Agency

Revision History

Revision	Prepared By	Reviewed By	Approved By	Date
0 – First Issue	A. McLeod	S. Poudel	L. Brand	29/05/2026
1 – Final Issue	A. McLeod	S. Poudel	L. Brand	03/07/2026

Address Amplitude Consultants PTY LTD
Level 2, 15 Astor Terrace
Spring Hill QLD 4000
Australia
E-mail info@amplitudepower.com
Phone (07) 3905 9030
Website https://amplitudepower.com/

Executive Summary

The transition of the Australian power system toward high penetration of inverter-based resources (IBR) is fundamentally reshaping the design and operation of protection systems. Industry experience across Network Service Providers (NSPs), equipment manufacturers, system operators, and research organisations indicates that these changes are not theoretical, they are already being encountered in operational environments and are driving a coordinated, practical response.

Historically, many essential system services including system strength, inertia, voltage control, fault current contribution and oscillatory damping were inherent characteristics of synchronous generation. As these services are increasingly delivered by inverter-based resources, their behaviour becomes dependent on control systems rather than machine physics. Protection systems, which have traditionally relied on predictable fault currents, stable voltage references and strong system conditions, are therefore being challenged by the same transition. The tasks examined in this report collectively explore how changes in the provision of essential system services are influencing protection performance and what adaptation strategies are emerging across industry, academia and international practice.

A consistent finding across industry stakeholders is that traditional protection approaches, particularly those reliant on fault current magnitude and predictable network behaviour, are progressively losing reliability. Inverter-based resources typically deliver limited and highly variable fault current, often influenced by proprietary control strategies, resulting in reduced sensitivity and increased uncertainty in fault detection. This behaviour challenges the foundational assumptions of conventional protection schemes, including time-current grading, directional elements, and distance protection.

Despite these challenges, established protection technologies remain in widespread use, but their application is becoming increasingly selective and context dependent. Line current differential protection is broadly recognised as the most reliable primary scheme in weak-grid environments where communication infrastructure is available. However, in many distribution and remote systems, practical constraints necessitate continued reliance on conventional protection methods, adapted through modified settings, mode dependent operation, and simplified coordination approaches.

Operational experience confirms that protection performance degradation occurs progressively rather than abruptly. As system strength declines, time-current grading schemes are most affected, followed by directional and distance based protection. Even robust schemes such as differential protection face limitations due to communication requirements and deployment constraints. This reflects a broader shift in power system behaviour, where system response is increasingly governed by inverter control dynamics rather than physical machine characteristics.

In response, the industry is adopting a range of transitional, adaptive protection approaches. Rather than replacing existing schemes, this approach augments them with additional supervisory logic, and communication-assisted functions. Examples include hybrid protection schemes combining frequency and current-based indicators, adaptive settings groups, and increased use of system level monitoring tools such as synchrophasor based wide-area measurement systems. Emerging technologies such as

travelling-wave (TW) and time domain protection are also being explored, although their application remains largely confined to transmission level systems.

A critical barrier identified across stakeholders is the lack of transparency and standardisation in inverter fault response behaviour. Limited access to reliable data on fault current magnitude, duration, and phase characteristics constrains protection design, coordination, and validation. This issue is compounded by the increasing use of software-defined control strategies, which introduce variability between manufacturers and operating conditions.

There is broad consensus that future protection systems must transition from purely measurement-based approaches toward behaviour aware frameworks. This shift requires enhanced understanding of inverter control dynamics, improved system observability, and the development of methods to interpret dynamic system behaviour during disturbances. While artificial intelligence and data-driven approaches are under investigation, their application in primary protection remains limited due to requirements for determinism, transparency, and validation.

The convergence of industry experience and academic research highlights a clear set of priorities for the next phase of development, including:

- Establishment of standardised inverter fault response characteristics
- Improved model transparency and access to high-resolution operational data
- Validation of protection approaches through EMT simulation and hardware-in-the-loop testing
- Development of frameworks for incorporating control-system dynamics into protection decision-making
- Evolution of regulatory and standards frameworks to support these changes

Overall, the industry is not undergoing a disruptive replacement of protection systems, but rather a gradual and pragmatic evolution. Existing protection methodologies continue to provide the foundation of system security, while new techniques are incrementally introduced to address the challenges posed by inverter-dominated networks.

The key conclusion is that protection in future power systems will require integration of traditional electrical measurements with an understanding of control-system behaviour, supported by enhanced data, improved standards, and coordinated industry research collaboration.

Contents

1. Introduction

1.1 Recognition of CSIRO and AEMO Support

This research was undertaken with the support of the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Australian Energy Market Operator (AEMO) as part of the Australian Research in Power Systems Transition (AR-PST) program. The authors acknowledge the valuable technical input and guidance provided by CSIRO and AEMO subject matter experts throughout this stage of the research.

In addition, this work draws heavily on the contributions of a broad range of industry specialists across NSPs, technology vendors, system operators, and research organisations, who provided insights through interviews, questionnaires, technical discussions, and the sharing of documentation. While it is not practical to recognise all contributors individually in this section, their collective input was critical to shaping the findings and conclusions presented in this report.

1.2 Context: Why This Research Is Critical to the Australian Power System Transition

Australia's electricity system is undergoing a rapid and irreversible transition driven by high penetrations of IBRs, increasing electrification of transport and industry, and the emergence of new operating paradigms such as Virtual Power Plants (VPPs) and DERs. These developments enable decarbonisation and long-term efficiency gains, but they also introduce material technical challenges for protection coordination, system strength, small-signal stability, voltage regulation, and secure operation — particularly in weak grid conditions, remote systems, and networks experiencing rapid changes in generation mix.

Many existing protection philosophies, stability assessment techniques, and compliance frameworks were developed for systems dominated by synchronous generation with high short-circuit strength and predictable fault behaviour. As IBRs increasingly displace synchronous plant, protection systems must operate under reduced fault levels, faster electromagnetic and control dynamics, non-linear control interactions, and greater uncertainty in system topology and operating conditions. These issues are particularly pronounced in distribution networks with high DER penetration and VPP aggregation, as well as in remote or isolated power systems where inherent system strength margins are limited.

1.3 Cost and Constraint Implications for the Electricity Industry

From an industry perspective, these challenges have direct cost and risk implications. Inadequate protection performance or overly conservative mitigation strategies can lead to unnecessary network augmentation, increased reliance on synchronous condensers or network support services, and constraints on DER and renewable energy integration. For example, network augmentation and system strength remediation measures can involve capital investments of tens to hundreds of millions of dollars per region, while protection-related constraints may limit the utilisation of existing assets or delay renewable connections. Conversely, improved protection strategies, better-targeted stability detection, and more informed compliance approaches have the potential to defer capital expenditure, reduce operational risk, and improve asset utilisation.

The benefits of such improvements are likely to become increasingly material over the next five to ten years, as DER penetration, VPP participation, and electrification accelerate and existing technical margins are progressively eroded. While this report does not undertake an economic assessment, it identifies pathways through which future work could more rigorously quantify how improved protection performance and stability detection may alleviate emerging technical constraints, strengthen system margins, and delay the point at which network augmentation or operational limits become binding.

This report addresses these challenges through a structured program of industry engagement, technical review, and research synthesis across eight interrelated tasks. These tasks include direct engagement with Australian NSPs to understand field-level challenges and current mitigation practices; assessment of emerging system architectures such as VPPs and their implications for protection and system strength; evaluation of new technologies and advanced protection strategies proposed by original equipment manufacturers (OEMs); review of Australian academic research and international projects; investigation of protection issues in remote systems and microgrids; and targeted analysis of voltage, active power, and reactive power instability detection relevant to compliance with National Electricity Rules (NER) clause S5.2.5.10.

In addition to the activities undertaken within the defined project scope, the research process gave rise to an innovative research postulate that was developed independently and outside the agreed tasks. This postulate is not assessed, validated, or endorsed as part of the funded work and is included in Appendix A for completeness and to inform potential future research directions.

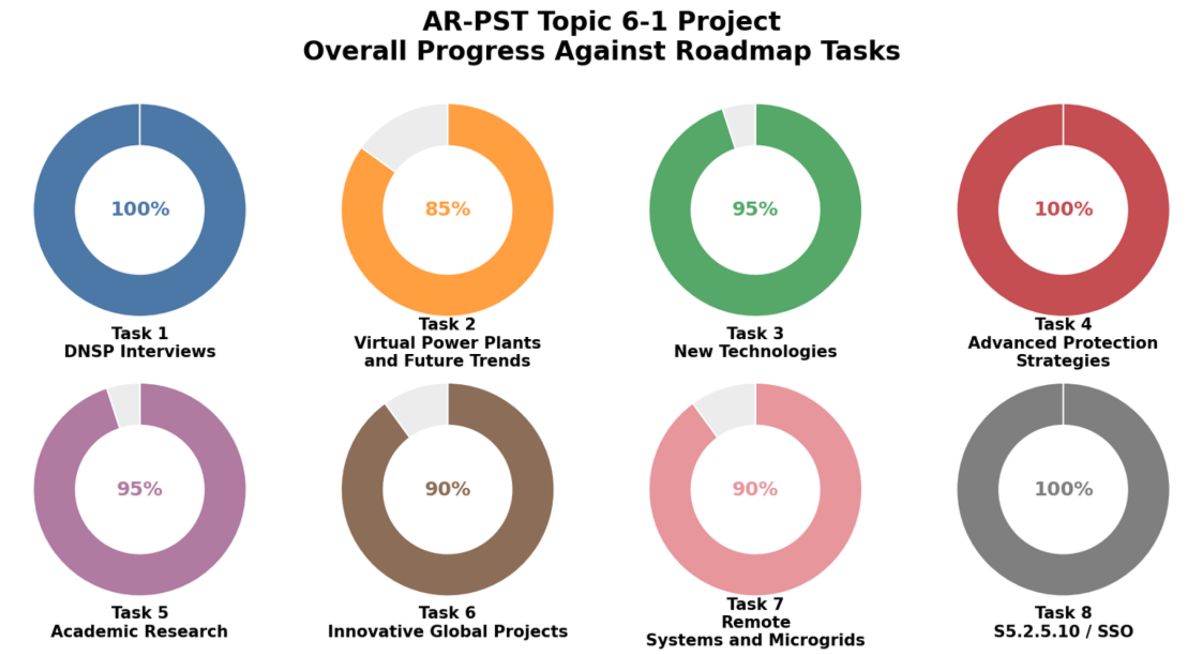
1.4 Alignment with the 2021 AR-PST Roadmap

The scope of this project was defined through eight work packages examining protection challenges associated with IBRs, evolving network architectures, emerging technologies, distributed energy resources, remote power systems and subsynchronous oscillations (SSO). Collectively, these work packages align strongly with the objectives of the AR-PST Topic 6 research program, which seeks to identify, quantify and maintain the technical characteristics and system services required for the secure operation of increasingly inverter-dominated power systems.

The AR-PST Topic 6 roadmap identifies a number of priority technical areas including protection performance, fault current characteristics, system strength, system stability, damping of oscillatory phenomena, distributed energy resource integration, grid-forming inverter capability, and the evolving technical requirements of future power systems. Through a combined methodology of literature review, stakeholder engagement and synthesis of contemporary industry practice, this project provides practical insights into each of these areas, while identifying emerging challenges, current industry responses and future priorities for research and development.

Further, the project directly supports several of the high-priority technical needs identified within the Topic 6 roadmap, including fault current characteristics, protection performance, damping of subsynchronous oscillations, inverter control interactions, DER integration and the application of grid-forming technologies. The findings therefore provide an important industry perspective that complements ongoing analytical, modelling and simulation-based research activities being undertaken within the broader AR-PST program.

Figure 1: AR-PST Topic 6-1 Roadmap Alignment



The percentages shown in Figure 1 represent the assessed degree of alignment between each research task and the priority areas identified within the AR-PST Topic 6 roadmap. Alignment was assessed based on the extent to which each task contributed to the AR-PST Topic 6 objective of understanding and maintaining secure, reliable and resilient operation of increasingly inverter-dominated power systems. Consideration was given to each task's contribution to understanding the impact of inverter-based resources on protection performance, system security, stability and the provision of essential technical system services.

The basis for this assessment is reflected throughout Section 3.1 (Context and Sector Relevance), which demonstrates how the eight work packages collectively address the protection, stability and operational challenges associated with increasing penetrations of inverter-based resources across the Australian electricity sector.

2. Problem Definition

This chapter examines the specific technical mechanisms through which inverter-based resources create challenges for protection system performance. Understanding these mechanisms is essential for evaluating the mitigation strategies and new technologies examined in subsequent chapters.

2.1 Fault Magnitude and Response Characteristics

When a short circuit occurs on a network supplied by synchronous generators, the magnetic flux in each machine forces current to flow through the fault path according to physical laws that cannot be altered by software or control systems. Synchronous machines deliver fault currents of several times their rated current, providing a clear indication and distinct signature of fault conditions. This response is consistent across manufacturers, predictable under all operating conditions, and stable throughout the fault duration.

Inverter based resources synthesise alternating current using power electronic switches controlled by software algorithms. Fault currents are limited to between 1.0 and 1.5 times rated capacity due to semiconductor device ratings and the resulting current might end up resembling normal load current more closely than a classical fault signature.

Variability compounds detection challenges. The fault current from an inverter depends on the control algorithm, the operating mode at fault inception, the type of fault, the voltage depression, and manufacturer specific design choices. Protection settings developed for one manufacturer's equipment may not provide reliable operation when different manufacturers' inverters are connected to the same network.

These characteristics affect multiple protection element types. Overcurrent elements, for example, may not detect faults reliably when current magnitudes are very low or remain close to load levels. In addition, distance relays might sense unstable impedance trajectories failing it to operate or operate spuriously.

2.2 Phase Angle Behaviour and Directional Discrimination

Synchronous machines maintain a stable phase angle tied directly to the physical position of the rotor. During network disturbances, mechanical inertia naturally limits rapid phase shifts. Traditional protection relays rely on these predictable voltage and current characteristics for directional discrimination, fault location, and coordination.

Conversely, IBRs utilise fast-acting control loops to continuously adjust output current, voltage and phase angle. During faults, IBR behaviour can differ significantly from synchronous generation and may vary depending on the inverter control strategy and manufacturer implementation. Furthermore, many inverter control systems actively suppress negative-sequence current injection (I_2) during fault conditions. This can significantly reduce the negative-to-positive sequence current ratio (I_2/I_1). As a result, protection schemes that rely on sequence current magnitudes, sequence current ratios, or sequence-based directional quantities may experience reduced sensitivity, degraded directional discrimination, and coordination challenges.

2.3 Sequence Components and Unbalanced Fault Detection

Synchronous machines inherently produce substantial negative sequence current during unbalanced faults. The physics of these machines guarantee this response.

Inverter based resources produce negative sequence current only if their control systems are programmed to do so. Many inverter control schemes actively suppress negative sequence current to prevent unbalanced loading of the power electronic components. Even when negative sequence injection is implemented, the magnitude and phase angle vary between manufacturers and may not match the characteristics expected by protection relays.

Negative sequence-based protection elements may fail to detect unbalanced faults due to suppressed or inconsistent negative sequence injection. Faulted phase selection algorithms may incorrectly identify faulted phases when the expected relationship between zero sequence and negative sequence currents does not hold. Ground directional elements that rely on negative sequence polarisation may fail to assert or may indicate incorrect direction.

2.4 Harmonic Content and Fault Signature

Synchronous machines produce nearly pure sinusoidal waveforms with minimal harmonic distortion. On the other hand, inverter switching processes generate harmonics and interharmonics, particularly during fault conditions when control systems operate at their limits.

Protection algorithms built on clean, sinusoidal phasor measurements face difficulties with distorted waveforms. Differential schemes may misinterpret internal versus external fault conditions due to harmonic induced false differentials. Distance elements may calculate incorrect impedance values. Harmonic blocking or restraint functions may not operate as intended when the harmonic content differs from the transformer inrush patterns they were designed to detect.

2.5 Weak Grid Effects on Protection Measurements

Weak grids exhibit higher voltage sensitivity, rapid angle changes, and magnified interactions between IBR control loops and network impedances.

Under weak grid conditions, voltage may collapse quickly during faults, leaving protection elements with very limited time or clarity to correctly identify the nature of the event. Phase-locked loop (PLL) circuits that track grid frequency may lose synchronisation during voltage depressions, causing erratic inverter behaviour that further confuses protection algorithms [1]. The behaviour of transformers, lines, and IBRs becomes more tightly coupled, and classical assumptions about fault direction, phase relationships, and stability margins may no longer be reliable.

Weak grid environments increase the likelihood of unusual protection behaviours, including underreach or overreach of distance zones, inconsistent directionality decisions, and loss of selectivity between upstream and downstream devices.

2.6 Sub Synchronous Oscillations and Stability Interactions

Sub synchronous torsional interactions and sub synchronous control interactions, particularly when amplified by series compensated lines or long cable systems, can lead to undamped oscillation modes [2]. The active power control and AC voltage control loops of renewable IBRs may contribute to oscillating modes, especially when connected through long cable systems with significant capacitance.

Sub-synchronous oscillations (SSO), control driven resonances, voltage oscillations, and frequency fluctuations may distort phasor measurements or mimic the characteristics of faults. In some cases, the system may experience fast dynamic conditions that cause relays to misclassify stability events as faults or vice versa. Differentiating between a rapidly evolving instability and a genuine fault becomes increasingly challenging as IBR control systems react quickly to disturbances.

2.7 Coordination Across Mixed Technology Fleets

Modern power systems comprise a diverse mix of synchronous machines, grid-following (GFL) and grid-forming (GFM) inverter-based resources, STATCOMs, active filters, battery energy storage systems, photovoltaic (PV) generation, virtual power plants (VPPs), and a wide range of protection technologies. Each technology exhibits distinct fault response characteristics, resulting in increasingly complex interactions during network disturbances.

Protection schemes have traditionally been developed around fault current and voltage characteristics associated with synchronous-machine dominated power systems. As inverter-based resources become more prevalent, these assumptions are increasingly challenged. Fault current magnitude, phase angle, sequence current content, and dynamic response may vary significantly depending on the inverter control philosophy, operating condition, and manufacturer implementation.

Fault ride-through strategies introduce additional complexity by actively modifying inverter behaviour during disturbances. Current magnitude, current angle, and positive- and negative-sequence current injection may be adjusted dynamically to satisfy ride-through and network support requirements. Consequently, protection devices may observe substantially different fault signatures and operating characteristics for the same network fault condition. These variations can reduce protection sensitivity, complicate directional discrimination, and create coordination challenges, particularly where multiple technologies and vendor implementations coexist within the same network.

2.8 Distribution Level Protection

Fuse based protection, which still forms a major component of Australian distribution networks, struggles when fault currents are low and variable. Recloser coordination becomes complex when current direction changes throughout the day. DER trip settings may conflict with network protection objectives. Short duration or low magnitude faults may remain undetected.

These challenges at the distribution level compound the issues at transmission level, contributing to a system wide decline in protection certainty.

2.9 Summary

The transition to inverter-based resources introduces multiple concurrent challenges for protection system performance. Reduced fault current magnitude undermines the sensitivity of current based protection elements. Variable phase angles during faults compromise directional discrimination and can cause relays to assert incorrect fault direction. Suppressed or inconsistent sequence components render negative sequence-based protection unreliable for unbalanced fault detection. Harmonic distortion introduces errors in phasor calculations, affecting both impedance measurement and differential comparison. Weak grid operation reduces the clarity of protection measurements and narrows stability margins, while sub-synchronous oscillations create dynamic conditions that protection systems may misinterpret as fault events.

These challenges do not occur in isolation. A single fault event in a weak grid with high IBR penetration may simultaneously present reduced current magnitude, unstable phase angles, inadequate sequence components, and harmonic distortion. Protection systems must contend with multiple degraded indicators at once, often during the narrow time window available for correct fault identification and clearance.

Technologies such as grid-forming IBRs may partially address stability related concerns by maintaining voltage and frequency support during faults, potentially enabling reliable protection operation at lower short circuit ratios. However, protection performance remains dependent on the specific fault response characteristics of inverter-based resources, which differ fundamentally from those of synchronous machines.

In addition to differing control philosophies across manufacturers, fault ride-through (FRT) requirements, current limiting strategies, and network operating conditions can significantly influence inverter behaviour during disturbances. The interaction between network topology, inverter controls, and current limiting functions may result in substantially different current and voltage measurements for similar fault types occurring at different locations within the network. Consequently, protection devices may observe markedly different fault signatures under ostensibly similar fault conditions, complicating directional discrimination, fault identification, and protection coordination. These variations continue to present challenges for the development of universally applicable protection solutions across inverter-based resource technologies.

Each subsequent chapter explores approaches to these challenges, examining new protection technologies, advanced algorithms, operational experiences, international case studies, and regulatory considerations.

3. Research

3.1 Context and Sector Relevance

The work is relevant across multiple electricity sector domains. Transmission networks are increasingly experiencing weak-grid conditions as synchronous generation is displaced, resulting in lower fault currents and evolving system strength characteristics. These changes have direct implications for protection coordination, voltage stability, and the detection of oscillatory events. Distribution networks face complementary challenges as DER, customer-side storage, and VPPs introduce reverse power flows, variable fault levels, and operational complexity beyond the design scope of traditional protection schemes. In remote or islanded systems, including microgrids and small industrial networks, limited system strength, reduced fault levels, altered power flow patterns, and reduced network redundancy can amplify operational vulnerability. These conditions may introduce additional protection coordination, directional discrimination, and fault detection challenges, requiring careful consideration of protection and control strategies to maintain reliability, safety, and cost-effectiveness

Integration of DER and VPPs further complicates the interactions between sector areas. Aggregated DER operations influence local distribution conditions and propagate effects upstream to transmission networks, impacting system strength and protection coordination. Advances in protection systems, including adaptive, differential, and non-current-dependent schemes, have applicability across these networks, particularly under weak-grid or DER-rich conditions. Across all sectors, regulatory and standards frameworks, including NER clause S5.2.5.10 and DER/VPP connection standards such as AS/NZS 4777, provide a common foundation for operational limits, protection requirements, and network security obligations. The interplay between these sector areas is critical. For example, operational characteristics of DER and VPPs in distribution networks can affect transmission-level protection and system strength, highlighting the need for coordinated approaches across voltage levels.

Similarly, protection solutions developed for microgrids can inform strategies for isolated parts of the main grid, while regulatory and standards frameworks provide consistent guidance across all sectors. By situating the research in this sector-wide context, the report establishes a foundation for understanding how the eight interrelated research tasks collectively address pressing challenges in the Australian electricity system.

3.2 Scope and Approach

The research was designed to systematically investigate protection, stability, and compliance challenges across the Australian electricity system. It combined literature review, targeted industry engagement, and technical analysis to generate actionable insights and support evidence-based recommendations.

The research program was structured around eight interrelated tasks, which provided a framework for investigating key sector challenges. These tasks encompassed practical engagement with NSPs to understand field-level operational challenges, assessment of emerging system architectures such as VPPs, evaluation of new technologies and advanced protection strategies, review of Australian and international academic research, and targeted analysis of remote systems, microgrids, and regulatory compliance requirements. Collectively, the tasks addressed both the technical and operational dimensions of protection and stability in DER-rich and evolving network conditions.

The methodology involved a comprehensive review of academic literature, technical reports, and industry publications to establish the state-of-the-art in protection strategies, DER integration, and system stability. Targeted engagement with NSPs, OEMs, and subject matter experts was conducted through interviews, workshops, and questionnaires, capturing operational experience, mitigation strategies, and practical insights. Confidential data provided by participants was managed in accordance with agreed protocols. Technical analysis, including scenario evaluations and modelling, was performed where appropriate to explore system behaviour under weak-grid, high DER, and remote or microgrid conditions. Proprietary and commercial software tools used in analysis are identified in the appendices, maintaining transparency and reproducibility.

Detailed documentation of methodologies, test procedures, and questionnaires ensures that professional peers could replicate the research and obtain substantively identical results. By integrating literature review, industry engagement, and technical analysis into a coherent approach, the research delivers sector-relevant insights, identifies knowledge gaps, and informs recommendations for both operational and planning domains, while maintaining rigor, transparency, and alignment with regulatory and standards requirements.

4. Industry Engagement Summary

This Section records the contributing organisations and individuals named in the body of the report, the engagement mode used in each case, and the sections of the report in which their input appears.

4.1 Network Service Provider Contributions

The seven NSP contributions are integrated throughout Chapter 5. The following bullets reproduce the position taken by each NSP, drawn directly from the body of the report.

- **Transpower (New Zealand)** differentiates between weak grids with traditional synchronous generation and weak grids with IBR based generation. In settings with little or no synchronous contribution, Transpower has applied directional overcurrent, voltage dependent directional overcurrent, current differential, distance and impedance, and distance with communication aided weak infeed logic. For IBR dominant areas, designs increasingly select current differential and voltage based protections. Transpower indicates that protection cannot realistically be modified for each IBR controller type unless industry standardises IBR controller responses, and that GFM inverters and synchronous condensers would help by producing a fault response closer to that of a synchronous machine.
- **TasNetworks** applies current differential schemes on lines connecting to IBRs and implements route diverse inter trip schemes. TasNetworks applies current differential utilising positive sequence, negative sequence and zero sequence current differential. TasNetworks has used synchrophasor based anti-islanding schemes to detect islanded operation of a wind farm in Tasmania, and has deployed a STATCOM at 22 kV to aid post fault voltage recovery.
- **Horizon Power** in low fault level conditions intends to change to a different settings group that allows enough fault current to operate the protection devices, accepting that protection grading can be compromised. Trade-offs are made to trip sections of the network to prioritise safety over reliability of supply, and if there are multiple smart devices (reclosers) Horizon Power tries to implement definite time curves to manage selectivity. They are trialling negative phase sequence protection, and has started looking into synchrophasor for wide area protection. A GFM inverter system trialled in the Horizon Power network has under fault events caused isolated micro networks within the network.

- **Powerlink** reports that differential current based protection has proven effective in weak grid areas and can be set sensitively, with pickup below full load current. Powerlink operates TW protection on selected 275 kV feeders in a non-tripping, fault locating application, and operates synchrophasor based wide area protection schemes. Powerlink describes safety as the highest priority with bias toward sensitivity over security, and states that at present there is no requirement for IBRs to demonstrate protection quality fault current and that it would be beneficial for the rules to include a minimum standard for fault current.
- **Endeavour Energy** has had instances where normal overcurrent pickup was being exceeded by reverse distributed generation back feed, necessitating conversion to a directional element and voltage-controlled overcurrent blocking on a meshed distribution network. Endeavour Energy normally uses a sensitivity factor greater than 1.5 (fault level over pickup) and ensures at least 1.2 times maximum loading. Endeavour Energy reports that AS 4777, NER Chapter 5, and AEMO guidance are evolving and ambiguous and sometimes conflicting at certain frequencies or voltages, and notes that black box nature of inverters is an industry gap [1].
- **Energy Queensland** observes that AS 4777 is currently silent on weak grid performance and grid-forming capabilities, and that the draft AS 5438:2025 behind the meter interoperability standard aligning communication protocols, interoperable inverter capabilities, and test requirements to standardise domestic inverter systems. Energy Queensland described a portfolio of innovations including a TW protection trial conducted near Townsville using Schweitzer relays, early fault detectors using radio receivers on poles to triangulate partial discharge locations, settings group changes for microgrids, a Grid Cube state estimator for dynamic operating envelopes (DOE), a Distributed Energy Resource Management System (DERMS) project, and an underfrequency supervised overcurrent hybrid scheme. Energy Queensland also described remote and islanded examples including the Mossman HV microgrid (a 22 kV network using a grid-forming inverter, approximately 600 kW / 1.1 MWh battery) and a SWER network pole top battery investigation using 30 kW grid-following systems.
- **Power and Water Corporation (PWC)** contributed with information covering the Daly River hybrid system, the Tennant Creek single bus system, and the Darwin to Katherine power system. PWC protection engineering team developed a hybrid protection approach drawing on a 2021 Schweitzer Engineering Laboratories technical paper, applying logical AND coordination between a frequency-based element and an overcurrent element with the objective of reducing fault clearing time to approximately 180 ms. Testing indicated that the SEL 751 and SEL 751A required significant computation time to produce a stable rate-of-change-of-frequency (RoCoF) estimate when the rate of change exceeded approximately 2.5 to 3 Hertz (Hz) per second.. Notwithstanding the observed RoCoF estimation delay, the implemented scheme successfully achieved fault detection and clearing within approximately 80–100 ms during a recorded fault event [2].

[1] The proprietary nature of inverter control and protection algorithms can limit the ability of network operators to predict fault behaviour and assess protection performance consistently across different technologies.

[2] RoCoF measurement performance can be influenced by inverter control behaviour and low-inertia system conditions. Refer Section 8.5.2 for further discussion.

4.2 Protection Relay OEM Engagement

Section 8 records that three protection relay OEMs participated in industry collaboration through structured questionnaires and direct technical interviews between November and December 2025.

- **Schweitzer Engineering Laboratories (SEL)** — Microsoft Teams interview on 14 November 2025. SEL described protection algorithms that operate in the time domain using high speed sampling at megahertz (MHz) scales, implemented for differential, distance, and directional elements, with field deployments at 500 kV transmission level in Brazil. TW protection is available as a commercial product offering, including TW differential, directional, and fault location functionality. SEL described a power swing detection algorithm that tracks the rate of change of impedance and requires no user settings. The PowerMax secondary level controller was described as having been deployed in Australia since approximately 2010, with installations at Chevron Gorgon and Wheatstone facilities and at Worsley Alumina in Western Australia, and a recent project in New South Wales at approximately 5 MW scale. SEL stated that the industry is far from trusting AI based algorithms for protection tripping decisions and expressed interest in participating in future CSIRO industry research collaborations.
- **Hitachi Energy Grid Automation** — written response to the technical questionnaire, December 2025. The response described a significant installed base of protection relays for IBR connected systems. Distance protection is stated to be capable of being set as low as 5 percent of nominal current. The response described patented model-based line differential protection developed specifically to handle connection to IBRs, and a patented double ended fault location algorithm developed specifically for IBR applications. The response stated that global sites, products, systems, and development cycles are certified to IEC 62443 4, IEC 62443 3 3, IEC 62443 4 1, and IEC 62443 4 2. Forward facing statements regarding future requirements, product roadmaps, or AI integration could not be provided, and pilot deployments and R&D activities were stated to be subject to non-disclosure agreements with customers. Representation in relevant IEC and IEEE working groups was confirmed.
- **Schneider Electric** — partial response to the questionnaire on 18 December 2025, addressing only questions relating to artificial intelligence integration, future technology roadmaps, and simulation capabilities. The mid-range protection relay platform was stated to have recently implemented AI as part of the algorithm for Directional Transient Earth Fault (DTEF) detection. The response explicitly characterised this implementation by stating that the implementation of AI in this instance is to assist conventional fault detection methods with specific tasks in the processing chain. The high-end protection relay platform was stated to be capable of running in a virtual environment as a Digital Twin of the hardware-based device.

4.3 CSIRO Subject Matter Expert Contributions

CSIRO Energy contributed directly through subject matter expert sessions are recorded in the body of the report.

- **On protection strategy scalability**: Thomas Wearne provided an overview of the current protection solution landscape, which was supported PWC. For large scale systems, synchronous condensers remain the preferred option, as alternative technologies are still maturing and primarily targeted toward smaller networks.
- **On frequency as a proxy for source impedance**: frequency response analysis can offer valuable insight into system strength and source impedance, making it a useful component within protection schemes. Its applicability is limited in complex multi-source networks where fault conditions may not

produce clear or consistent frequency characteristics, and it is most effective in simple system topologies.

- **On the inverter equipment information gap:** Energy Queensland has expressed considerable concern regarding the absence of standardised inverter specifications. Manufacturer datasheets frequently omit critical information, particularly fault current magnitude and duration, which is essential for effective protection coordination. The need to establish minimum performance requirements was emphasised.
- **On two approaches to protection improvement**: the solution landscape consists of two complementary streams. The first focuses on enhancing inverter performance, particularly with respect to fault current contribution and dynamic response capabilities. The second centres on advancing protection relay functionality through improved logic, hybrid protection elements, and faster processing. Both streams will need to be applied in combination to achieve robust protection outcomes.

4.4 Microgrid and Mining Sector Engagement

BEC Engineering contributed through input from a Principal Protection Engineer, whose role is described in the body of the report as covering legacy infrastructure, modern digital relay technologies, and protection scheme performance in low fault level environments. The Agnew Gold Mine microgrid was used as the principal case example. The body of the report records that such systems typically range from approximately 2 to 3 MW up to around 45 MW, with renewable generation comprising 60 to 70 percent of installed capacity but contributing approximately 10 to 20 percent of actual energy output, and that operations run predominantly in islanded mode (approximately 80 percent). Group setting schemes apply approximately 4000 A pickup in network connected operation and approximately 475 A in islanded operation. Differential protection on SEL 787L relays is typically applied to critical infrastructure such as generators of 2 MVA and above and transformers of 6 MVA and above. Approximately 95 percent of protection systems at these sites continue to rely on conventional overcurrent and earth fault elements, with earth fault protection remaining more robust under degraded conditions.

4.5 System Operator and International Laboratory Engagement

AEMO engagement is captured throughout the report. Section 11.5 documents the West Murray Zone (WMZ) incidents between 2018 and 2023, including an 8 Hz event and a separate sustained oscillation at approximately 17 Hz involving several solar farms. AEMO and NREL jointly conducted impedance-based stability analysis using site specific, black boxed IBR models in Power System Computer Aided Design (PSCAD) and Electromagnetic Transient (EMT) simulation environments. Section 11.6 describes AEMO's four stage frequency scanning proof of concept, with Stages 1 through 3 complete and Stage 4 underway as of late 2025, and AEMO's in house Frequency domain Admittance based Stability Tool (FAST).

NREL contributed through a stakeholder interview with N. K. Prabakar conducted on 9 December 2025. The interview is referenced throughout Section 10.2. US utility requirements for grid-forming inverter capacity relative to load were reported to vary from 1.5 times to 3.5 times. TW protection has been successfully deployed at transmission level in the United States, with distribution level TW products not yet widely available. AI and machine learning (ML) based protection was identified as a significant emerging technology with no field deployed systems at present, but with field deployment anticipated within two to three years. Major relay manufacturers including ABB, Eaton, Siemens, and SEL were reported to be developing AI based protection technologies. Grid-forming capability is becoming a standard requirement for battery energy storage systems in the US, with grid-forming mode typically operated only in islanded conditions. Hardware in the loop testing was confirmed as standard practice in the US for protection performance validation.

4.6 New Technology Manufacturer Survey

Two industry survey responses have been received from manufacturers of new system strength technologies, both respondents reported conducting validation using grid simulators, EMT models, and alignment with the Universal Interoperability for Grid-forming Inverters (UNIFI) specifications and reported reliable behaviour at short circuit ratios (SCRs) as low as 2.5 to 3. They also identified gaps in standards and the absence of utility level specifications as barriers to wider deployment.

4.7 International Utility and Reference Material

Chapter 9 of the report draws on documented international experience. NamPower (Namibia) deployed SEL T400L TW relays on the 220 kV Khan to Omburu transmission line (113.6 km), and a phase to ground fault on 4 February 2020 was reported to have been cleared by the TW differential element in 1.09 ms compared with 13.87 ms for the line current differential. The Public Service Company of New Mexico deployed SEL T400L relays on a 345 kV series compensated line and became the first utility worldwide to enable direct tripping rather than monitoring mode. Commonwealth Edison confirmed single ended TW fault location accuracy of 200 m on a 91.1 km 345 kV line. National Grid ESO conducted the Stability Pathfinder Phase 2 procurement in 2022, awarding GBP 323 million for 11.55 GVA of short circuit level in Scotland, and analysis by SMA (Germany) through the Energy Systems Integration Group found that grid-forming batteries provided 65 percent of contracted inertia but only 21 percent of contracted short circuit level, while synchronous condensers provided 35 percent of inertia but 79 percent of short circuit level. International Council on Large Electric Systems (CIGRE) Technical Brochure 896 (April 2023) [3] and Technical Brochure 909 (October 2023) [4] are referenced in the report as international consensus on protection in IBR rich networks and SSO in power electronics dominated systems respectively.

4.8 Convergent Themes

Six themes emerge in the body of the report where multiple contributors take broadly consistent positions. The contributor list against each theme is restricted to those whose position on that specific theme is recorded in the source.

- **Differential protection at IBR interfaces.** Transpower, TasNetworks, Powerlink, BEC Engineering, SEL, and Hitachi Energy each describe differential schemes as a preferred approach where fault levels are low or where IBR fault response disrupts conventional schemes.
- **Source independent protection.** Transpower, SEL, NREL, and CIGRE Technical Brochure 896 each describe protection that is independent of source characteristics — particularly differential and TW — as a strategic direction for IBR rich networks.
- **Inverter behaviour transparency.** CSIRO (Thomas Wearne) raised the absence of standardised inverter specifications, including the omission of fault current magnitude and duration in datasheets, attributing the concern in part to Energy Queensland. Endeavour Energy described the black box nature of inverters as an industry gap. Powerlink described the absence of a requirement for IBRs to demonstrate protection quality fault current. The University of Melbourne, Monash University, and the University of Queensland each describe black box vendor models as a constraint on their analytical frameworks.

- **GFM useful but not a substitute for synchronous fault current.** Transpower, Powerlink, Energy Queensland, BEC Engineering, and NREL each describe GFM inverters as providing improved voltage and inertial behaviour but limited protection quality fault current. The UK Stability Pathfinder Phase 2 analysis by SMA quantifies this as grid-forming batteries delivering 65 percent of contracted inertia but only 21 percent of contracted short circuit level.
- **Hybrid and group setting schemes.** Energy Queensland (underfrequency supervised overcurrent), PWC (frequency element with overcurrent, targeting approximately 180 ms clearing), Horizon Power (mode dependent settings groups), and BEC Engineering (grid connected versus islanded group settings) each report trial or field deployment of hybrid or mode dependent schemes.
- **AI based protection: not yet field ready.** NREL (field deployment anticipated within two to three years), SEL (industry described as far from trusting AI based algorithms for tripping decisions), Hitachi Energy (no forward facing statements available on AI integration), and Schneider Electric (AI implemented in Directional Transient Earth Fault detection, characterised as assisting conventional methods) each describe AI in protection as developing rather than mature.

5. Task 1 – Interviews with NSPs

5.1 Introduction

NSPs build and operate the protection systems that secure Australia and New Zealand's electricity networks, and their operating experience is the most direct source of evidence on protection performance in weak grids as IBR penetration grows. Seven NSPs returned substantive contributions to this study through structured interviews and a 25-question written survey: Transpower, TasNetworks, Horizon Power, Powerlink, Endeavour Energy, Energy Queensland and PWC.

This chapter is organised by NSP. Each subsection consolidates one utility's contribution as a single narrative, with cross NSP themes drawn together in Section 5.10. Individual personnel are not named; all statements are attributed to the contributing organisation.

5.2 Transpower (New Zealand)

Transpower differentiates two weak grid regimes that behave differently for protection. In weak grids with little or no synchronous contribution, conventional schemes (directional overcurrent, voltage dependent directional overcurrent, current differential, distance with weak infeed) has worked with reasonable success. Where IBR generation is dominant, protection studies now focus on avoiding non-operation and maloperation risks such as directional overcurrent and distance, and current differential and voltage-based protection are increasingly selected. Two screening triggers apply: (i) IBR penetration above 30 percent of synchronous generator response triggers a protection review, and (ii) inverter sourced fault current above 15 percent of the non-inverter sourced component seen by distance or directional elements requires assessment and open-ended mitigations for all affected (e.g., line differential and voltage based protections) and non-affected protection functions (e.g., distance/directional elements). For existing devices, modifications may not be possible, or clear information may not yet exist to modify the function appropriately.

Transpower notes that some protection manufacturers recommend using voltage instead of current-based fault phase selection methods for distance protection and other logic for fault detection such as delays and supervisions. Transpower states that more detailed manufacturer guidance would be beneficial and suggests that inverter control standards and regulations could be codeveloped to avoid impacting non-faulted phases and provide more traditional fault response.

On modelling, steady state generation models in fault analysis software are the baseline, with EMT studies requested for weak networks. Field validation testing of IBR fault response is not yet required but is under consideration. Transpower notes problems with harmonic filters or hybrid device influence on relay sensitivity and communication-assisted protection under distorted waveform conditions appears to be more with transient responses rather than harmonic content. Grid-forming inverters and synchronous condensers are expected to help distance and directional protection by providing fault responses closer to a synchronous machine. TW is considered expensive, not applicable everywhere, requires changes and backup protection for busbars is still required. Line differential and voltage-based protection are being selected in recent designs to avoid potential issues with weak grid and IBR based generation. Backup Zone 2 clearance can be up to 1.5 seconds, so fault current presence over that interval is needed for reliable backup protection [3].

No major IBR attributable mis operations have occurred. One unusual event islanded a wind farm, with load matching at 100 MW for the auto reclose dead time; on reclose, the line tripped on Zone 1 distance protection during the disturbance, followed by successful reclose. A separate weak infeed line protection scheme maloperated during a remote fault in a non-IBR weak grid and was resolved through a relay manufacturer logic improvement.

NER compliance is not directly relevant in New Zealand; Transpower complies with the NZ Electricity Industry Participation Code rules, and reports increasing guidance, protection studies, consideration and updating protection systems can be required for meeting the rules associated with protection dependability and security in weak-grid conditions.

Transpower considers standardised test cases or compliance frameworks could help validate protection performance, but notes that aligning the supporting generation models, performance requirements and regulation effort is a barrier; additionally installing post fault monitoring and data capture, including Phasor Measurement Unit (PMU) data, would help.

5.3 TasNetworks

TasNetworks insists on dual current differential schemes on lines connecting to IBRs, supported by route-diverse intertrip arrangements; loss of both communications media trips the IBR generation. Distance is only used as backup protection and no specific modifications have been made for low fault level operation. IBRs are not permitted to feed in islanded mode in the TasNetworks regime, which removes a significant class of weak grid challenge.

[3] This observation highlights a potential misalignment between conventional backup protection time requirements and the fault-current characteristics of inverter-based resources. Refer Section 8.2 for further discussion regarding inverter fault-current capability, current limiting and fault response characteristics.

Differential schemes utilises positive, negative and zero sequence current to balance sensitivity and security; as a unit protection scheme it requires no coordination with other protection schemes.

TasNetworks has used a synchrophasor-based anti-islanding scheme to detect islanded operation of a wind farm in Tasmania, and has deployed a STATCOM at 22 kV to support post fault voltage recovery and assist wind farm ride through.

Most relays and schemes operate on 50 Hz phasors extracted from the waveform, providing inherent filtering against non-fundamental content.

5.4 Horizon Power

Horizon Power operates the regulated networks outside the SWIS in Western Australia, dominated by remote islanded systems.

In low fault level conditions, Horizon Power intends to change to a different settings group that allows enough fault current to operate the protection, accepting that grading is compromised and traditional devices such as fuses cannot operate. Under low fault current conditions, overcurrent pickup is traditionally set at 50 percent of the minimum fault level, including high order faults; the practical limitation is that feeder protection can trip off, constraining feasible network configurations.

Horizon Power addresses this by deploying additional inverter capacity so that at least 50 percent of the design fault output is produced. Trade-offs are made to trip sections of the network to prioritise safety over reliability of supply. This is due to their network being smaller, and if there are multiple smart devices (reclosers) Horizon Power tries to implement definite time curves to manage selectivity.

Coordinating protection between IBRs, synchronous generation and network devices under weak grid conditions is made with group settings depending on modes of generation mode, although is limited in low fault level scenarios and is also managed with definite time curves. As far as possible faults in the Horizon Power network as still considered one directional and they either limit or control generation outside of what their system produces via a DERMS. Negative phase sequence protection is being trialled for non-sinusoidal or unbalanced IBR fault currents, and synchrophasor measurement is being investigated as a part of a wide area protection scheme. Network faults are typically cleared within 1 second, and Horizon Power aims for IBRs to sustain their fault current for at least 2 seconds whilst IBRs can generally sustain up to 10 seconds. Enough IBR capacity is deployed to achieve an SCR of two. A grid-forming inverter trial in the network unintentionally created isolated micro networks under a fault event, a useful counterexample to the assumption that grid-forming behaviour is benign under all conditions. Horizon Power supports noted it would be beneficial to provide guidelines for the regulator and all NSPs to agree what is compliant for IBR systems, and offered no comment on NER or AEMO matters as they are vertically integrated and can provide all aspects of power supply.

5.5 Powerlink

At 275 kV, IBR connections are only permitted via cut in and cut out arrangements; tee connections are not allowed at that voltage level because of protection complexity and reduced system strength. At 132 kV, tee connections are permitted reflecting differences in protection scheme requirements and operational philosophy at lower voltage levels. Synchronous condensers are considered viable for system strength support, but recent installations have incurred capital costs in the order of $150 million. Duplicated line differential protection is the primary scheme in weak grid areas because pickup can be set below full load current and the scheme is immune to low fault levels. Overcurrent is rarely used in the transmission network, with the limited exceptions of reactive compensation equipment and a small number of customer connection backups where limitations may persist to avoid restricting circuit load transfer capability under maximum load conditions. Where overcurrent is used, the fault level should ideally be at least twice the pickup for positive operation, but its effectiveness is limited under minimum generation dispatch conditions, resulting in increased fault clearance time; this limitation cannot be reliably addressed by settings changes due to maximum power transfer requirements on the circuit. Accelerated distance is widely deployed, with weak infeed logic enabled at line ends in weak grid areas or with low fault current contribution.

Powerlink identifies the absence of a minimum IBR protection quality fault current standard in the NER as a requirement for IBRs to demonstrate protection quality fault current, such inclusion would ensure OEMs prioritise development in this area. This minimum standard could be Powerlink's proposed four point specification for IBR fault response to comply with improve reliability: (i) negative sequence current proportional to negative sequence voltage at the network connection point; (ii) the phase angle of the fault current from the generator at the point of connection (POC) is determinant and proportional to the fault loop impedance; (iii) the frequency of generator unit voltage during the fault remains in synchronism with the system voltage at the network connection point for the duration of the disturbance; and (iv) the generating unit shall be capable of providing fault current contribution for duration not less than the maximum circuit breaker fail or backup protection time. The minimum fault current duration for reliable protection is at least 500 ms for transmission and two to three seconds for distribution.

Powerlink has recently completed a review of their network protection systems to determine minimum fault levels across all lines and apparatus. Reduced SCR carries a risk of increased operate time and reduced measurement accuracy of protection systems, and Powerlink considers that power electronic devices currently have limited protection quality fault current capability; engagement with OEMs is ongoing to drive improvements in the control system algorithms to better support existing protection systems.

TW protection is in service on selected 275 kV feeders in a non tripping, fault locating application, to drive improvements in the control system algorithms to better support existing protection systems with performance is subject to ongoing assessment. Synchrophasor based wide area protection is in service with operate times slower than conventional circuit protection. Relays capable of detecting SSO are installed at IBR connections in a monitor only configuration; there is no established operational policy and no SSO occurrences have been recorded. Modelling is done in PowerFactory or PSCAD, and recognises Real-Time Digital Simulator (RTDS) may be useful prior to field testing such as using Common Format for Transient Data Exchange (COMTRADE) files created from modelling being played back through relays. For islanded systems, the design of the system including generator sources and protection systems must be considered in determining the suitability of the island. From a load perspective, the generator sources may need to be oversized to provide sufficient fault levels. For example, it may be required to install a battery Energy storage system (BESS) inverter with capacity of 2 or more times the maximum load to ensure existing overcurrent schemes will continue to function. Extensive tuning of the positive and negative sequence current injection would be required to ensure sufficient phase to phase, and phase to ground fault levels for protection operation, this must be considered during the project planning phase.

AEMO does not review or approve protection approaches; Powerlink submits event reports with protection performance details for all transmission faults. Powerlink considers that its current practices are sufficient and intends to maintain minimum fault levels and use differential protection.

5.6 Endeavour Energy

Endeavour Energy operates the distribution network across parts of Sydney, the Blue Mountains, Southern Highlands and Illawarra in New South Wales. Endeavour Energy intends to improve overcurrent performance during normal system operation with excess solar generation by applying an undervoltage check so the overcurrent pickup can be set closer to load. This is applied to normal power flow conditions with reliable directionality. There are circumstances where reverse distributed generation back feed has exceeded the normal overcurrent pickup, requiring conversion to a directional element. In one case a meshed distribution network used for voltage support in a weak area had the first recloser with very low reverse pickup due to low fault currents from the adjacent supply, and maloperated on reverse distributed solar generation; the solution being implemented in this case is voltage controlled overcurrent that blocks the reverse direction when voltage is healthy using fixed settings. This scheme will have a resistive-fault cut-off level where the voltage doesn’t collapse enough, at which point the sensitive earth fault and neutral voltage protection will be relied upon. The voltage-controlled overcurrent element will not be used where there are concerns of inverter logic that can limit negative sequence current and impacts to directional protection in fault scenarios. Two separate elements will be used, a non-directional voltage-controlled overcurrent element for detecting faults during micro-grid operation and directional overcurrent elements for detecting faults during meshed grid-connected operation.

Distance protection has been transitioned from mho to quadrilateral characteristics for sensitivity in weak grid areas, with current supervision set low enough for Zone 2/3 to detect minimum fault scenarios and instantaneous Zone 1 disabled where SIR is high. A few directional scheme mal-operations required adjustments to V and Q prioritisation, or positive and negative sequence polarisation, following manufacturer guidance. Mutual coupling and unreliable inverter responses mean that directional elements may not be appropriate close to an IBR source. Near IBRs, Endeavour Energy is not confident in ensuring fault detection through the IBR contribution and therefore trips the grid connection via intertripping or active or passive anti-islanding including undervoltage and neutral voltage displacement for earth faults.

Endeavour Energy normally uses a sensitivity factor greater than 1.5 (fault level / pickup) with at least 1.2 times maximum loading, with 1.5 as the floor in the company protection standard. When that is still insufficient for full utilisation of the feeder, voltage-controlled elements are being explored. Minimum fault current durations are 2 seconds primary and 4 seconds backup from IBRs are necessary for reliable protection unless NER requirements are less. Endeavour Energy does not model or test customer IBR installations; NER Chapter 5 compliance modelling is outsourced and there is no internal validation mechanism. For its own BESS installation, a time domain PowerFactory model verified the passive anti-islanding protection but there were clear non detection zones with matched generation and load that could not be avoided. They confirmed undetected islands are very easy to maintain during field testing. Endeavour Energy considers that IBR protection performance needs to be guaranteed and proven to NSPs by the proponent; the absence of an enforceable framework, is not acceptable they are connecting devices to the network that not only have unpredictable behaviour but even if proven, the behaviour can be changed via software without their knowledge. A drafted protection guidelines highlights the DER protection design risks: (i) primary plant and cable rating being exceeded due to additional fault current, (ii) mal grading of field devices due to in-feeds, (iii) desensitising existing feeder protection schemes, (iv) sympathetic tripping from reverse power flow, (v) false blocking of busbar blocking schemes due to reverse power flow, and (vi) prohibition of automatic and unsynchronised reclosing. The modelling tools to design against these risks are not available, and protection is still being designed as if DER is not generating during fault conditions.

Operational experience includes approximately four reverse power maloperation cases on overcurrent elements, resolved by raised pickups or network reconfiguration, and are also investigating voltage controlled overcurrent to futureproof designs for this issue. The 132 kV sub transmission network has not encountered fault levels too low for reliable detection. AEMO has been approached only for approval of longer critical clearance times for weak networks where communications based schemes are not justified. In remote areas, no intertripping is available; active anti-islanding had to be disabled due to flicker issues making it difficult to run the BESS in parallel mode and have a dependable trip on islanding. There has been multiple cases of the BESS failing to trip when unintentionally islanded. In intentional island mode there is no understanding of when the BESS will cross its control thresholds from a large unbalanced load into fault current mode, as it could treat both as load conditions and limit the output. Endeavour Energy see the black-box nature of inverter response as a gap in the current industry approach, and also identifies three specific NER S5.2.5 issues: (i) ride through requirements versus protection clearance time requirements are ambiguous, (ii) critical clearance time requirements are ambiguous for weak networks, and (iii) needed frameworks for imposing greater IBR behaviour transparency would help get more information from proponents and the ability to place responsibility to prove their accuracy to the proponents.

5.7 Energy Queensland

Energy Queensland's diesel off and isolated system projects are progressively adopting grid-forming inverters, with the philosophy of oversizing the inverter to deliver enough fault current to maintain existing protection schemes; for a 500 kW load a 1.5 MW inverter is typical. The oversizing strategy has introduced its own stability issues through low SCR with single generators, is expensive, and may not be sustainable long term. The Mossman HV microgrid islands a 22 kV network using a grid-forming inverter rated approximately 600 kW with a 1.1 MWh battery, sized to cover the entire network for fault current and protection. AS/NZS 4777 is silent on weak grid performance and grid-forming capabilities, although ABB and Pacific Energy were identified as having achieved AS/NZS 4777 certification for the grid-forming inverters used at Mossman, and SIG Energy is reported to operate continuously in grid-forming mode while grid tied indicating the standard does not prevent grid-forming operation. Differential protection is used on larger diesel off sites with dedicated feeders where economical. A separate trial of 30 kW pole top batteries on single phase SWER networks is constrained by the highly resistive nature of SWER and the absence of accurate EMT or PSCAD models for small inverters; Energy Queensland currently does not have a PSCAD model of a 30 kW inverter for this project.

A TW protection trial near Townsville with SEL relays produced acceptable results but is not seen as suitable for mass distribution network roll out due to short line lengths and reflections from cable joints, and requires significant expertise. Early fault detectors using radio receivers on poles to triangulate partial discharge locations have also been trialled. Settings group changes are commonly used for microgrids where communication-based protection settings that change based on operating conditions such as grid-connected vs islanded. Significant investment has been made with a Grid Cube State Estimator for calculating DOEs for dynamic connections that will run dynamic connections to individual customers greater than 30 kW. A DERMS project is under way but not yet fully commissioned to orchestrate DERs.

Weak grid performance of residential inverters remains largely unknown/untested, and the behind the meter interoperability standard is in draft (drawing on IEEE 1547, SunSpec Modbus 1.2, IEEE 2030.5:2018 and (OCPP) 2.1). VPP and aggregator communication protocols lack interoperability standards, where current implementations remain retailer or battery vendor specific. This draft standard AS 5438:2025 'Interoperability Requirements for Inverter Energy Systems' was open for public comment from 18 February to 22 April 2026. It maps these minimum set of protocols, capabilities to be supported by interoperable inverters, and testing and verification requirements to standardise and support coordination of domestic inverters by inverter energy systems. It will allow rooftop solar and attached storage systems to communicate within an installation to maximise household benefits and enable more active participation in the wider electricity system.

Six technical challenges were identified across the interview: (i) negative sequence current deficiency as IBR penetration increases, that may be more relevant for distance protection than basic distribution overcurrent schemes; (ii) absence of distribution level high frequency recording equipment to monitor sub-synchronous oscillations; (iii) a knowledge gap on how DC source limitations (battery chemistry, power electronics, pre loading conditions) constrain AC side fault current capability, that is critical for small standalone power systems; (iv) harmonic interference with protection algorithms, such as second harmonic blocking for transformer inrush; (v) fault current is now software or firmware dependent rather than based on inherent machine characteristics, raises protection trust and reliability concerns; and (vi) the absence of detailed fault current capability curves for residential size sub 10 kW inverters that would help finetune protection coordination. STATCOM trials at LV and MV provide voltage management and ride through but do not contribute MW or SCR. Ergon's SVCs are planned for replacement, likely with STATCOMs in the order of 10 MVAr. There is no internal appetite at Energy Queensland to own or operate synchronous condensers.

5.8 Power and Water Corporation

PWC operates three regulated Northern Territory systems: Darwin to Katherine, Alice Springs and Tennant Creek. The Daly River project (commissioned approximately ten years ago) used a German manufactured 40 foot container housing a 5 MW / 5 MWh BESS with an AC coupled PV array, replacing diesel generation. The protection approach used binary group settings (Group 1 for diesel, Group 2 for inverter) on simple SPAJ 51 overcurrent relays, with settings lowered for the battery inverter higher source impedance. No downstream discrimination was required as the feeders did not have reclosers for sectionalisation.

Tennant Creek is a single bus radial 22 kV system with five feeders, two of them very long. High impedance faults on the long feeders have repeatedly caused system black events: voltage typically drops to approximately 0.6 per unit rather than collapsing, online generators see the fault as load and overload, frequency falls with RoCoF reaching 16 Hz per second or higher, and the protection grading (bus feeder coordinated with multiple downstream reclosers) produced clearing times exceeding 400 ms which exceeded the ride through window of online generation. Power and Water's protection engineering team developed a hybrid protection scheme drawing on a 2021 SEL technical paper (Inverter Based Radial Distribution System and Associated Protective Relaying). The scheme applies AND logic between a frequency element and an overcurrent element, targeting 180 ms clearing. The initial design used RoCoF, but SEL 751 and 751A relays required approximately 300 ms of computation time to produce a stable RoCoF estimate above 2.5 to 3 Hz per second, eliminating the available time margin. The design pivoted to a conventional underfrequency element with stochastic correlation analysis, paired with an overcurrent pickup at approximately 400 A (against a normal feeder current never exceeding approximately 200 A). The hybrid logic runs in parallel with the conventional overcurrent and Under-Frequency Load Shedding (UFLS) schemes. Since implementation, one fault event has been recorded and cleared in 80 to 100 ms. Power and Water emphasises that the scheme is not yet proven and remains early stage.

In the Darwin to Katherine system, a 300 km 132 kV line carrying multiple solar sites separates during the wet season due to lightning strikes, and when the interconnection locks out the Katherine region experiences system black via RoCoF or UFLS. A business case exists for a high specification power conversion system (PCS) based BESS or Hitachi style BESS similar to the Channel Island installation. Even on diesel alone in island mode, high impedance faults continue to cause system black; an example provided was a fruit bat landing on the long 22 kV Gorge feeder. The Tennant Creek hybrid scheme or settings group switching is a candidate solution. Single bus systems readily automate group switching with the operating source, but multi bus systems require communications and elevate the control system itself to protection critical infrastructure. BESS synthetic inertia can mask the generation deficit at contingency and prevent UFLS from operating in time; adequate post contingent inertia for UFLS is treated as non negotiable. The SEL PowerMAX technology was discussed as a third layer of control for stabilising inverter groups against sub synchronous resonances; implementation challenges include nested control loop interaction with intermediate Plant Power Controllers and the requirement for hardware in the loop testing. Power and Water is in the early stages of PMU deployment for real time system strength monitoring. Inverter datasheets routinely omit fault current magnitude and duration, leaving a fundamental coordination data gap, and the path forward is seen as parallel improvement in both inverter fault response and protection relay logic.

5.9 Ausgrid

Ausgrid was contacted and confirmed the topic as an active area of work, but no substantive written or follow up response was received within the engagement window. Indicative information was provided being Ausgrid reports finding fault level contribution very low at some IBR connections has difficulty modelling the fault response; a gap is identified between power system engineers and inverter manufacturers in framing IBR behaviour; and Ausgrid has been awarded the Hunter and Central Coast renewable zone Stage 1 and is building infrastructure for inverter based generation. A follow up engagement is recommended.

5.10 Convergent Themes

Convergent themes across the seven substantive contributions are clearest in the protection scheme hierarchy: line current differential is the preferred primary scheme where the application supports it (Transpower, TasNetworks, Powerlink); distance and directional schemes are increasingly relegated to backup or assisted roles with weak infeed and communication aided logic (Transpower, Powerlink, Endeavour Energy); voltage controlled and voltage supervised elements are the lever of choice in distribution where differential is uneconomic (Endeavour Energy). On the limits of IBR fault response, every NSP that addressed the question identified the same core problem: IBR fault current is limited by design and cost, is software defined and can change without NSP knowledge, and is not reliably specified in vendor datasheets. Three NSPs (Powerlink, Endeavour Energy, Energy Queensland) identified this as an industry gap requiring a regulatory response. Standardised test cases are unanimously supported among the NSPs that commented (Transpower, Horizon Power, Endeavour Energy), with implementation effort identified as the principal barrier.

Divergent positions concern whether existing design practice is sufficient (Powerlink yes at transmission; Transpower and Endeavour Energy no, particularly in distribution), the role of inverter oversizing (used at Powerlink and Energy Queensland, but introducing low SCR stability problems at Energy Queensland and unintended micro networks at Horizon Power), and adoption maturity for adaptive techniques (in service at Powerlink for fault location and wide area; trial only elsewhere; not deployed for primary tripping at any NSP).

The strongest consolidated guidance is the Powerlink four point IBR fault response specification (proportional negative sequence current, determinant phase angle, synchronous voltage frequency, fault current duration not less than the maximum circuit breaker fail or backup protection time), independently corroborated by Transpower (need for traditional fault response), Horizon Power (voltage source behaviour), Endeavour Energy (enforceable IBR performance) and Energy Queensland (lack of detailed capability curves). On minimum fault current duration, the responses cluster around 500 ms transmission (Powerlink) and 2 seconds distribution (Powerlink, Endeavour Energy, Horizon Power), with 1.5 seconds for Zone 2 backup (Transpower) and 4 seconds backup at Endeavour Energy. Endeavour Energy’s three identified NER S5.2.5 ambiguities (ride through versus clearance time, critical clearance time in weak networks, and the absence of an IBR behaviour transparency framework) together with Energy Queensland's observations on AS/NZS 4777 weak grid silence provide a coherent reform agenda.

5.11 Future Work

Recommended future work consolidated from this engagement:

- Codify the Powerlink four point IBR fault response specification into NER S5.2.5 with associated compliance testing and reporting requirements.
- Establish an enforceable IBR behaviour transparency framework, including verification that as commissioned protection performance is maintained through subsequent software changes.
- Reconcile the ride through and protection clearance time requirements in the NER and AEMO guidance; clarify critical clearance time for weak networks.
- Update AS/NZS 4777 to address weak grid performance and grid-forming capabilities, and align with the behind the meter interoperability standard now in draft.
- Develop industry shared modelling tools for distribution protection design under realistic DER fault response; benchmark relay computation time for RoCoF and frequency derivative algorithms above 2.5 Hz per second across vendors.
- Replicate the Tennant Creek hybrid frequency and overcurrent scheme on other weak remote 22 kV networks (such as Katherine) to build a multi site evidence base.

6. Task 2 – Virtual Power Plants and Future Trends

6.1 Introduction

VPPs represent a pivotal evolution in power system management, offering dynamic solutions to the challenges of renewable energy integration, grid stability, and demand-side management [Liu et al., 2023] [5].

The concept of weak grids has become increasingly relevant as power systems evolve. Converter-based renewable energy sources (RES) and BESS that are asynchronously connected to the system are becoming increasingly widespread. However, with this integration, several relevant stability issues are being experienced in areas with little synchronous generation, particularly in terms of voltage stability [Bialek et al., 2021] [6]. This report examines how VPPs can address these challenges through coordinated control and optimization of distributed energy resources (DERs).

6.2 Definition and Concept

A VPP is a network of distributed energy resources (DER) including solar photovoltaic systems, battery storage, controllable loads, and electric vehicles that are aggregated and coordinated using advanced software and communication technology. VPPs enable these individually small resources to function collectively as a single, dispatchable power plant from the perspective of grid operators and electricity markets.

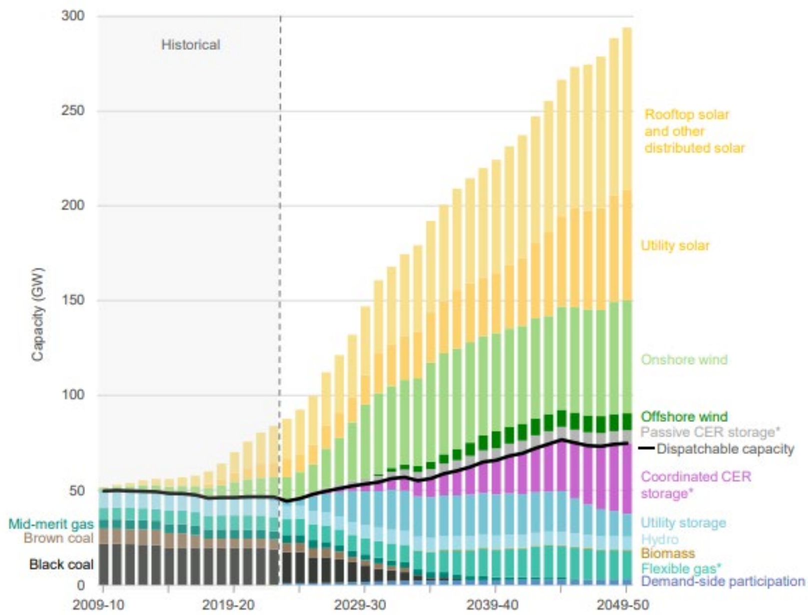
Unlike traditional centralized power plants, VPPs leverage the distributed nature of modern energy resources to provide rapid response times, enhanced resilience, and the ability to optimize across diverse locations and technologies. The control systems employed by VPPs allow real-time monitoring, forecasting, and dispatch of aggregated capacity to deliver multiple value streams including energy arbitrage, frequency control ancillary services (FCAS), network support services, and demand response.

6.3 Strategic Importance for Australia

Australia leads the world in per-capita rooftop solar adoption, with over 2.5 million installations representing more than 10 GW of distributed generation capacity. This penetration of DER, coupled with the retirement of synchronous coal-fired generation, presents both unprecedented opportunities and critical challenges for grid stability and system strength.

AEMO's 2024 Integrated System Plan (ISP) [7] forecasts that by up to 90% of the NEM’s coal-fired power stations are projected to retire before 2035, and the entire fleet before 2040. Meanwhile DER generation capacity is expected to have a dramatic increase, driven by deployment of rooftop solar and other distributed solar technologies, with consumer energy resources (CER) such as residential batteries and electric vehicles having an increased role in the energy matrix. The resulting NEM capacity through to 2050 is shown in Figure 2 [7] below.

Figure 2 – Capacity, NEM (GW, 2009-10 to 2049-50) [7]



Notes: “Flexible gas” includes gas-powered generation and potential hydrogen capacity.
“CER storage” means consumer energy resources such as batteries and electric vehicles.
Projections for “Rooftop solar and other distributed solar” and “CER storage” are forecast based on unit costs, consumer trends and assumptions about payments received to participate in the electricity market.

6.4 Current State of VPPs in Australia - AEMO VPP Demonstrations Program [8]

The AEMO VPP Demonstrations project [9], conducted in collaboration with the Australian Renewable Energy Agency (ARENA), Australian Energy Market Commission (AEMC), and Australian Energy Regulator (AER), represents the most comprehensive assessment of VPP capabilities in the National Electricity Market (NEM). Commencing in July 2019, the demonstrations provided insights into how VPPs can be effectively integrated into market frameworks while maintaining system security.

The program onboarded eight VPP portfolios across all mainland NEM states, representing a total registered capacity of 31 MW. Although participation was open to all technologies, every participating VPP utilised battery storage systems, reflecting the current market emphasis on battery-based solutions. The demonstrations confirmed that when consumer devices are effectively aggregated and coordinated, they can make a meaningful contribution to system security while also delivering financial benefits to participating households.

Key findings from the demonstrations showed that VPPs successfully responded to contingency frequency control ancillary service (FCAS) events and energy market price signals. Revenue generation was found to be strongly correlated with power system events, responsiveness to market conditions, and participation in FCAS markets. The use of Application Programming Interfaces (APIs) provided the necessary operational visibility to enable detailed performance analysis and verification of VPP responsiveness. Insights gained from this program directly informed the Market Ancillary Service Specification (MASS) consultation process and contributed to subsequent regulatory reforms supporting VPP integration.

6.5 Consumer Energy Resources (CER) Growth Trajectory and Network Planning Challenges

The 2025 Transition Plan for System Security (TPSS) [10] and the draft 2026 ISP inputs [11] forecast rooftop solar growing from around 25 GW today to 42.5 GW by 2036 and 72 GW by 2050, with embedded storage jumping from 2.2 GW to 9.8 GW by 2036. AEMO has flagged challenges around inadequate visibility of aggregated CER, limited forecasting ability, and minimum system load risks.

Industry consultation indicates that VPP uptake is expected to cause significant issues in network planning, protection and control. Several mechanisms are being deployed to address these challenges:

- DOEs can help solve some planning issues while also addressing visibility challenges by providing real-time export limits that respond to network conditions.
- Common Smart Inverter Profile – Australia (CSIP-AUS) [12]) is becoming ubiquitous, providing a base level of visibility and control capability for aggregated DER.

6.5.1 Voltage Quality and Ramping Concerns

A significant emerging concern relates to voltage quality impacts from coordinated VPP dispatch. As electricity prices change, aggregated VPP response may cause rapid shifts in power flow that could stress network voltage regulation equipment. Voltage regulators may experience substantially increased tap-changing operations, raising questions about the rating and duty cycle of diverter resistors in tap changers that were not designed for such frequent operation.

This represents an area requiring further investigation: the interaction between market-driven VPP dispatch and network voltage quality has not been comprehensively studied, yet the physics suggest that rapid, coordinated power flow changes across distributed resources could have material impacts on voltage regulation infrastructure.

6.5.2 Integrated Planning Requirements

Industry stakeholders emphasise that some level of integrated planning between CER rollout and network/protection planning is essential, along with mechanisms to share learnings across the sector. Without coordinated development, the risk exists that network infrastructure and protection schemes will be increasingly stressed by DER behaviour that was not anticipated in their original design.

6.6 VPP Behaviour During Network Disturbances

Understanding how VPP aggregations respond to network disturbances remains an area requiring further research. The most comprehensive work to date on DER response during faults is AEMO's distributed PV [13] studies, which have documented how rooftop solar systems disconnect during voltage disturbances.

The challenge for protection engineers is that VPP response during faults depends on the aggregated behaviour of potentially thousands of individual inverters, each responding according to their firmware settings and local conditions. Unlike synchronous generation, where fault current contribution follows well-understood physical laws, inverter-based VPP response is software-defined and can vary significantly between installations.

This creates uncertainty for protection coordination: traditional protection schemes assume predictable fault current magnitudes that can be used to discriminate between fault and normal operating conditions. When VPP fault response is variable and potentially limited, protection settings may need to be more conservative, potentially affecting coordination and selectivity.

6.7 Electric Vehicles and Vehicle-to-Grid Integration

Electric Vehicles (EVs) represent the next frontier for VPP scaling, offering transformative potential as a distributed storage resource. If fully electrified, the Australian vehicle fleet could provide substantial collective storage capacity. Realising this opportunity depends on the advancement of Vehicle-to-Grid (V2G) technology, which enables EV batteries to shift from being passive loads to mobile, dispatchable assets.

6.7.1 Technical and Operational Challenges

Integrating EVs into VPPs introduces several technical and operational challenges requiring ongoing research and innovation:

- Managing uncertainty in vehicle availability due to variable connection periods driven by driving patterns
- Addressing battery degradation concerns by carefully controlling cycling to preserve warranty and lifespan
- Ensuring vehicles maintain adequate state-of-charge levels to meet owners' transportation needs
- Manage voltage and load unbalance arising from the unpredictable pattern of which cars are connected or disconnected.

6.7.2 Fault Current and Protection Considerations

While international standards such as IEEE 1547 [14] mandate fault ride-through (FRT) and dynamic voltage support, the inherent thermal limits of inverter-based DERs typically restrict fault current contribution to 1.1–1.5 times their rated current. Consequently, the proliferation of V2G-enabled EVs, if following current grid-following philosophies, will continue the trend of declining available fault current compared to traditional synchronous-heavy networks.

6.7.3 Anti-Islanding Concerns

Anti-islanding detection presents a significant emerging concern for V2G integration. Current standards are limited to test requirements of a single DER. However, in a real islanding event, multiple DER may be present on the island, which could make it more likely to form an unintentional island that evades detection.

Industry experts suggest there may need to be new forms of anti-islanding protection developed specifically for high-DER grids. The interaction between multiple grid-following inverters during an islanding event is not well characterised by single-device testing, and the collective behaviour may differ substantially from individual device performance. Similar concerns may apply to grid-forming inverters, which can actively support voltage and frequency during islanded operation, potentially reducing the effectiveness of conventional island detection methods.

6.7.4 Phase Unbalance Considerations

An emerging practical challenge with V2G integration relates to phase unbalance protection. Unlike fixed installations where phase allocation can be controlled, EV charging occurs wherever vehicles are plugged in, which cannot be controlled at the network level. This means that phase unbalance can vary significantly depending on which vehicles are connected and which are out driving.

This presents coordination challenges for protection schemes that rely on unbalance detection, as the "normal" level of unbalance in a network with significant V2G penetration may be substantially higher and more variable than in traditional networks[4].

[4] Refer Section 8.4 for further discussion regarding the impact of elevated background negative-sequence quantities on protection performance in DER- and V2G-rich networks.

6.7.5 Regulatory Framework

Standards Australia (2024), through the AS/NZS 4777.1:2024 revision [15], introduced explicit provisions for V2G technology with both AC and DC connection options, formally embedding the regulatory framework necessary for EVs to engage in bidirectional energy flow with the grid.

6.8 AS/NZS 4777 and System Integration

While AS/NZS 4777.2:2020 [16] establishes a regulatory foundation for grid connection by standardizing basic functions like Volt-Var and Volt-Watt response, stakeholder feedback suggests the standard is increasingly outpaced by the demands of weak and inverter-dominated grids.

6.8.1 Gaps in Current Standards

Interviews with DNSPs highlighted that the current framework remains silent on specific performance requirements for weak grid environments and lacks a standardized approach to grid-forming capabilities. This regulatory gap creates a fragmented landscape where compliance does not necessarily guarantee reliable performance under low system strength conditions, leaving protection engineers to navigate significant uncertainty. The development of standardised testing procedures, performance metrics, and compliance requirements for grid-forming technologies remains an important industry need.

A primary concern is the absence of standardized GFM requirements. Although AS/NZS 4777.2 does not explicitly prevent grid-forming operation, it provides no technical framework to govern it. Consequently, while manufacturers have achieved certification for grid-forming inverters, this certification only verifies compliance with basic connection rules rather than ensuring consistent GFM behaviours like virtual inertia or system strength support.

6.8.2 Small-Scale Inverter Performance Uncertainty

Generally, rooftop DER standards lag somewhat behind large-scale IBR requirements. There is limited published data specifically addressing small-scale inverter weak grid performance, creating a "black box" regarding the behaviour of residential inverters under 10 kW in weak grid conditions.

Unlike large-scale IBRs, the fault current capability and stability characteristics of these residential units remain largely unknown and untested. The lack of detailed fault current capability curves prevents fine-tuning of protection coordination, forcing utilities to rely on conservative, generic assumptions that may unnecessarily limit network hosting capacity.

6.8.3 Weak Grid FRT and Anti-Islanding

An important consideration is the potential conflicting behaviour between weak grid FRT requirements and anti-islanding discrimination. Enhanced FRT capability, which keeps inverters connected during voltage disturbances, may conflict with anti-islanding requirements that depend on inverters disconnecting when the grid is lost. Balancing these competing objectives in high-DER, weak grid environments represents a technical challenge that current standards do not fully address.

6.8.4 Software-Defined Protection Concerns

The transition to software-defined fault current means that protection reliability now hinges on proprietary firmware rather than immutable physical characteristics. This raise concerns that remote updates could alter fault response characteristics without the knowledge of the NSP.

6.9 Data and Visibility During Network Events

The ability to understand VPP and EV behaviour during network events depends critically on monitoring and data visibility. Current visibility of DER behaviour during network disturbances varies across the industry.

Most in-built monitoring in residential inverters and EV chargers is not fast enough to capture transient events, though these devices can typically indicate whether the inverter tripped during an event. This limitation means that detailed analysis of DER response during faults often relies on network-side monitoring or post-event investigations rather than device-level data.

Improving visibility of aggregated DER behaviour during disturbances remains an important objective for network planning and protection coordination. CSIP-AUS provides a foundation for steady-state visibility, but capturing dynamic response during transient events requires additional monitoring capability that is not universally deployed.

6.10 International VPP Examples and Best Practices

6.10.1 Germany – Next Kraftwerke [17]

The German market hosts one of Europe's most significant VPPs, operated by Next Kraftwerke. Founded in 2009, this entity aggregates approximately 13,000 medium and small-scale power-producing and consuming units across seven European countries, establishing itself as a benchmark for commercial VPP viability.

Central to these operations is the NEMOCS platform (Next Energy Management and Optimization Control System), a modular software-as-a-service solution that facilitates the connection, monitoring, and real-time operation of distributed assets.

The system allows for automated responses to market signals, such as the negative price response mechanism demonstrated in January 2017, when VPPs coordinated the automatic curtailment of 15 GW of wind production during negative wholesale prices.

6.10.2 Sonnen VPP (Shell-Owned) [18]

Sonnen, acquired by Shell in 2019, operates what it claims to be Europe's largest residential VPP. This network comprises over 25,000 batteries across Germany with a total capacity exceeding 250 MWh, with plans to expand to 1 GWh. The VPP provides frequency containment reserve to the German transmission grid and engages in wholesale electricity trading.

6.10.3 United Kingdom – Statkraft Virtual Power Plant [19]

Statkraft operates the UK's largest VPP, aggregating over 1,000 RES with combined installed capacity exceeding 10 GW. The Statkraft Unity platform provides a trading interface enabling participants to access electricity markets, with portfolio optimization, imbalance management, and settlement services.

6.10.4 United States – Emerging Deployments [19]

In the United States, the Department of Energy estimates that VPP capacity currently stands between 30 and 60 gigawatts, representing approximately 5% of nationwide peak electricity demand. By 2030, approximately 200 GW of new resources will be required to serve rising peak demand, positioning VPPs as a critical solution. The VP3 (VPP Partnership) alliance brings together technology providers, utilities, and aggregators to develop technical standards and regulatory frameworks for accelerated deployment.

6.11 Lessons from International Experience

International VPP deployments provide valuable insights for Australian implementations:

1. Technology Diversity – Successful VPPs integrate multiple technology types (solar, wind, biogas, storage, flexible loads) to optimize across varying market conditions and provide comprehensive grid services.
2. Consumer Value Proposition – Residential participation requires compelling financial benefits through either bill reduction, free electricity quotas, or revenue sharing from grid services.
3. Software Platform Sophistication – Advanced control and optimization platforms are essential for managing large fleets of distributed assets across multiple market participation mechanisms.
4. Regulatory Support – Mature VPP markets exhibit clear regulatory frameworks enabling VPP participation in ancillary service markets with appropriate performance standards and verification requirements.
5. Scalability Focus – Commercial VPP operators design systems for rapid scaling, with modular platforms that can accommodate thousands of additional assets without fundamental redesign.
6. Multiple Revenue Streams – Viability depends on stacking multiple value streams (energy arbitrage, FCAS, network support, capacity payments) rather than relying on single revenue sources.

6.12 Future Directions and Recommendations

6.12.1 Technology Development

The evolution of VPPs and their integration into weak grid environments demands focused advancement across several technical domains.

Grid-forming capability stands as the most critical development priority. VPPs equipped with grid-forming inverters can actively establish voltage and frequency references, providing synthetic inertia and system strength that partially compensates for retiring synchronous generation. This capability transforms VPPs from passive market participants into active grid stabilisation assets.

Forecasting and optimisation algorithms require substantial improvement to manage the inherent variability of aggregated DERs. Real-time coordination of thousands of distributed assets, each with unique constraints around battery state-of-charge, EV availability, and consumer preferences, demands sophisticated predictive models.

Communication architecture underpins all VPP functionality. Robust, low-latency protocols must ensure reliable coordination and dispatch even during network disturbances when VPP response is most critical.

6.12.2 Policy and Regulatory Framework

Realising the full potential of VPPs requires policy and market design that recognises and appropriately rewards their grid support capabilities.

Grid codes must evolve to address VPP participation in weak grid environments. Current frameworks, including AS/NZS 4777.2:2020, primarily govern grid-following behaviour and provide no technical foundation for grid-forming operation.

Incentive mechanisms should encourage VPPs to deliver services beyond simple energy arbitrage. Frequency control, synthetic inertia, and system strength contribution all provide genuine value to the power system, yet current market structures often fail to adequately compensate these services.

Ancillary service requirements need standardisation to facilitate VPP participation, and aggregation and market participation frameworks should be streamlined to reduce the administrative burden currently limiting deployment.

6.13 Conclusion

VPPs represent both a critical solution to Australia's energy transition challenges and a fundamental shift in how protection systems must operate. The retirement of synchronous generation removes the predictable fault current and inherent inertia that traditional protection schemes depend upon. VPPs offer a pathway to restore some of these capabilities through coordinated control of distributed resources, but only if protection systems evolve accordingly.

The transition to grid-forming control strategies within VPPs addresses protection challenges while enhancing system strength. Grid-forming inverters can provide controlled fault current contribution and maintain voltage references during disturbances, partially restoring protection coordination capabilities.

However, this introduces new complexities: managing interactions between multiple grid-forming sources, ensuring stability across varying grid conditions, and coordinating response across geographically dispersed assets.

Emerging challenges identified through industry consultation, including voltage quality impacts from market-driven VPP dispatch, anti-islanding detection in high-DER networks, phase unbalance from uncontrolled V2G connection, and the tension between weak grid FRT and anti-islanding requirements, highlight that significant technical work remains before VPPs can be reliably integrated at the scale anticipated by AEMO forecasts.

International experience from Germany, the UK, and the United States demonstrates that mature VPP markets can successfully coordinate thousands of distributed assets across multiple value streams. The technical platforms exist; the challenge lies in adapting these approaches to Australia's unique grid topology and ensuring that protection systems can accommodate the variable, software-defined behaviour of aggregated DER.

The path forward demands collaboration between VPP aggregators, NSPs, and regulators to develop protection approaches that accommodate variable fault current contribution while leveraging VPP capabilities for synthetic inertia and system strength. Success will determine whether Australia's world-leading DER penetration becomes a grid stability asset or an ongoing coordination challenge.

7. Task 3 – New Technologies

7.1 Introduction

As previously mentioned in other sections of this report, the rapid transition toward renewable energy and the retirement of traditional synchronous generators present fundamental challenges to modern power systems. Historically, Synchronous generators provided the inherent kinetic inertia and high, predictable fault currents required to maintain system strength and co-ordinate protection relays. With the integration of IBRs, the grid is increasingly forced to operate under reduced fault levels and encounter faster dynamics, non-linear control interactions, and greater uncertainty in system topology and operating conditions.

While the increasing penetration of IBRs has created new challenges, new and innovative technologies have rapidly evolved to address these emerging challenges. Solutions such as grid-forming battery energy storage systems (GFM-BESS), VSC-based high voltage direct current (HVDC) links, GFM STATCOMs, E-STATCOMs, low voltage (LV) active filters, and LV STATCOM and BESS devices offer new methods for strengthening weak networks, enhancing voltage stability, improving DER hosting capacity, improving power quality and supporting fault level needs.

To have a broader understanding of the technological capabilities of new devices and to assist with this section, an industry survey was conducted. While some responses are still pending, based on the feedback received from the two participants indicated that manufacturers emphasise growing deployment of DER supporting technologies including small scale and LV connected STATCOMs, active harmonic filters, and increasing grid-forming inverters to address system strength issues in weak and low SCR networks. They identify low short-circuit levels as a persistent challenge, affecting voltage stability and downstream protection operation; however, grid-forming controls, reactive power regulation, active power phase balancing, and LV ride-through capability were consistently highlighted as key solutions that maintain stability, support fault ride-through, and improve protection performance even at SCRs as low as 2.5 - 3. These devices can strengthen weak grids by maintaining internal voltage reference points, improving ride-through under severe dips, and in some cases increase local fault current contribution to ensure LV fuses and circuit breakers operate correctly.

Both respondents conduct rigorous validation using grid simulators, EMT models, and alignment with specifications to ensure reliable behaviour under high impedance conditions. Protection challenges are generally limited, though constrained fault current inherent to power electronics remains a known limitation, and there is little coordination between DER devices beyond oscillation detection and gain-adjustment mechanisms. Future pathways include broader adoption of grid-forming inverters, exploration of virtual synchronous machine (VSM) modes to enhance inertia and damping, and ongoing development of weak-grid-capable control features, although gaps in standards and the absence of utility-level specifications remain barriers to wider deployment.

Given the growing complexity of modern electricity systems, network operators and planners require a thorough understanding of how some of these emerging technologies can be deployed, both individually and in combination to mitigate system strength risks and support the ongoing transition to renewable, inverter dominated grid.

This requires rigorous assessment of not just the technical capabilities, but also the feasibility, manufacturer readiness, modelling requirements, control architecture and deployment challenges associated with each technology. Recent reviews of grid-forming inverter solutions highlight the need for coordinated integration approaches, careful management of control interactions, and validated modelling practices to ensure that these technologies can reliably operate under weak-grid and low fault level conditions.

The grid requires a number of key essential services to maintain stability in power grids and ensure correct operation of protection in the grid. These services include:

- System strength – how well the grid can handle disturbances and fluctuations in supply and demand.
- Fault current injection – required to ensure correct operation of key protection systems.
- Inertia and frequency control – providing active power when the frequency drops and absorbing active power when the frequency increase.
- Voltage control – steady state control of AC voltage and dynamic control during faults and disturbances.

As the energy sector continues to evolve, technologies capable of delivering the above essential system strength services are no longer confined to synchronous machines alone. The new technologies imitate specific elements of synchronous behaviour through advanced control strategies and they differ markedly in their design philosophy, operating modes, protection interactions, and deployment maturity, yet all share a common objective to ensure that modern, inverter dominated networks can remain stable, resilient, and adequately protected under conditions of reduced fault levels, weaker system strength, faster dynamics, and increased operational uncertainty. The following sections examine some of these technologies in detail.

7.2 Grid-Forming BESS (GFM-BESS)

A GFM-BESS represent one of the most significant recent advancements within the IBR technology landscape, particularly as networks transition towards high penetrations of distributed energy resources (DERs). Modern IBRs deployed in solar and wind farms typically operate using GFL control, synchronising to the network through a PLL and responding to voltage disturbances through direct current (DC) control loops. In contrast, GFM inverters establish their own internal voltage source, allowing them to provide controlled inertial responses, stabilise voltage and phase angle, and operate more effectively in conditions of low short-circuit strength. Recent developments have enabled GFM operation in applications combining wind farms with co-located energy storage, where the storage system allows the grid-forming inverter to deliver current boosts during disturbances, enhancing the overall resilience of the generation system under weak-grid conditions.

One of the most important findings in the literature is the demonstrated capability of GFM inverters to operate reliably at short-circuit ratios as low as 1.2, while also supporting nearby GFL inverters that would otherwise struggle to remain synchronised under such weak-grid conditions. The underlying advantage is that GFM inverters behave more similarly to synchronous machines, actively contributing to both voltage magnitude and phase angle regulation.

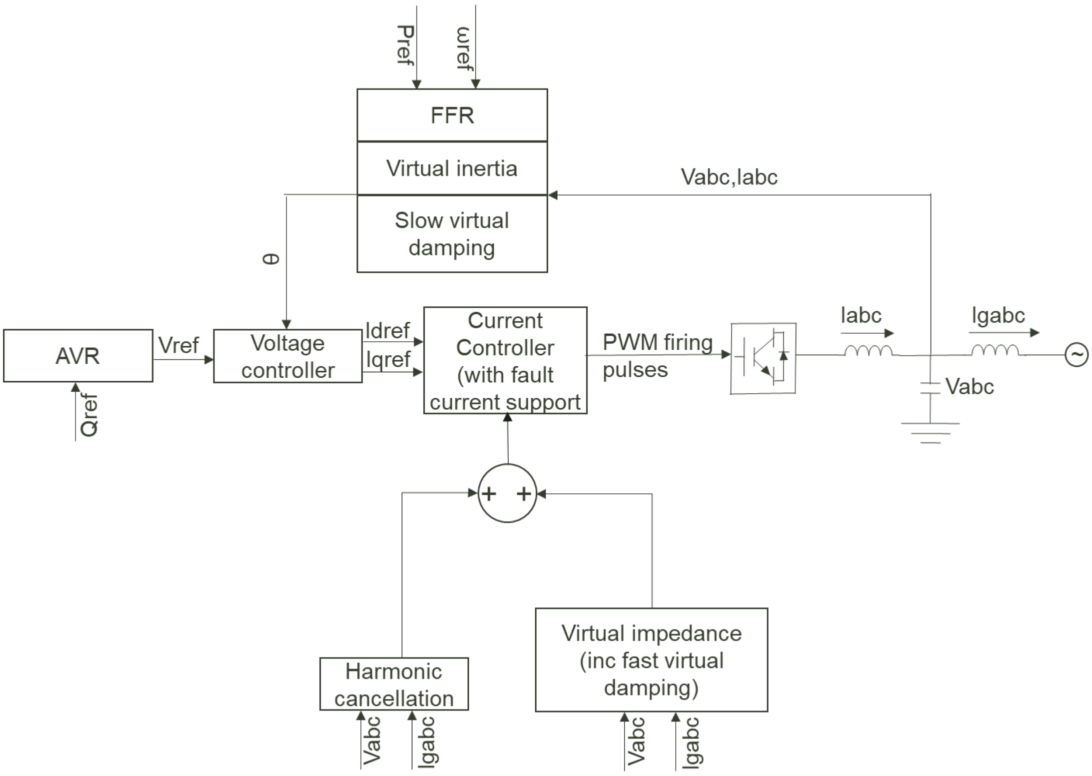
This ability provides a stabilising influence during steady-state and transient conditions and distinguishes GFM from traditional GFL devices whose reliance on PLLs makes them far more vulnerable in low-strength networks.

However, despite these strengths, the fault-current contribution capability of GFM-BESS remains fundamentally constrained by the physical limits of modern power-electronic devices. IBRs, whether GFL or GFM, are inherently current-limited and cannot deliver the high and predictable fault currents characteristic of synchronous machines. Typical GFM inverter behaviour reveals that while the initial fault-current peak may reach up to 1.6 p.u., this rapidly decays to a sustained level around 0.9 p.u., reflecting protection and thermal design constraints built into the inverter hardware and its associated cooling system.

Differences in the control algorithms, current-limit thresholds, and inertia reserve settings across OEMs lead to notable variation in the shape, duration and sequence content of fault currents; factors that directly influence protection system performance and the device’s contribution to minimum system strength. Some vendors provide current-boost features, enabling short-duration increases in fault current, whereas others propose oversizing the inverter hardware to increase contribution. Yet oversizing is costly, and inverters exposed to fault currents above their rated limits may also experience stability issues or may revert from GFM to GFL mode to maintain internal protection margins, precisely when their GFM behaviour is required most urgently.

The control block diagram given in Figure 3 visually breaks down the modular control loops of a GFM inverter (such as virtual inertia and virtual impedance), demonstrating that an inverter's dynamic response is an engineered software feature.

Figure 3 – Comprehensive GFM inverter showing the software nature of the inverter control [20]



This software-driven nature presents a unique opportunity and challenge at the same time compared to the synchronous generator. As highlighted in page 15 of the Aurecon report [20]:

"Unlike a synchronous generator where most capabilities are provided largely as an inherent bundle without the opportunity to add or remove any, each GFM BESS project can be designed based on specific needs of the power system to which it is connected to include some or all of the grid-support capabilities."

With GFM BESS, a layer of complexity arises in unbalanced fault conditions. Studies document significant variability in the negative-sequence current injected by GFM inverters, as well as variability in the frequency of the current relative to the system voltage, resulting in challenges for directional relays which rely on consistent negative-sequence angle relationships. In some cases, directional elements were unable to operate reliably due to phase-angle variation and frequency drift, and in others the inverter incorrectly identified the faulty phase during model-based assessment of asymmetrical events. These shortcomings stem from the software-driven nature of inverter control loops. Unlike synchronous machines, where electromechanical inertia imposes predictable behaviour, GFM inverters generate fault currents as a function of fast, proprietary control algorithms, making manufacturer-specific tuning critically important for real-world performance.

Another operational constraint arises from the energy storage system itself. Batteries must recharge between events, and their life-cycle constraints typically on the order of ~3000 charge/discharge cycles, place limits on sustained or repeated current-boost operation during disturbances. During storms or multiple-fault sequences, these constraints can affect the availability of headroom and the inverter's ability to repeatedly contribute to fault current or high-dynamic behaviour. GFM-BESS must therefore balance limited thermal headroom among multiple services, including inertia, fast frequency response (FFR), and fault-current support; meaning a trade-off is inevitable if one service saturates the inverter's power-electronic limits.

The difference between the inverter terminal current and the Point of POC current is another crucial consideration in the grid-forming BESS. System studies reveal that a plant's POC current depends strongly on the aggregate inverter MVA relative to the POC rating. A typical design practice is to oversize the inverters by 30% relative to the POC MVA, though higher ratios may be required to achieve fault-current levels consistent with site-specific protection requirements.

Beyond steady-state considerations, EMT-based studies demonstrate that GFM-BESS behaviour varies substantially across OEMs in both post-fault oscillations and damping capability. In a Transgrid study comparing multiple OEM batteries responding to the same disturbance, the post-fault voltage and current trajectories differed by as much as a factor of two in terms of damping effectiveness. These differences stem from proprietary implementations of virtual inertia, virtual impedance, PLL-decoupling strategies and current-limit behaviour. Highlighting this discrepancy, the Transgrid study concluded that (page 8) [21] :

"The finding is that among different types of GFM technologies, with the same size rating in MW and similar MVA (i.e. MVA at the inverter level aggregate), the effectiveness can be largely different (e.g. up to twice). These differences in the effectiveness mainly come from damping capabilities after the fault clearance and reduction in the fault level."

These characteristics underscore the broader challenge identified in the Sandia National Laboratories study [22], which concludes that existing phasor-based relay algorithms may not reliably operate with modern IBR control schemes, and that new protection technologies and settings philosophies will be required as synchronous generation is replaced by IBRs. Notably, the report recommends that jurisdictions require IBRs to inject negative-sequence current and maintain frequency control of current during unbalanced faults to support traditional protection methods; requirements that align with the emerging need to define GFM-specific performance standards in system strength frameworks. For grid-forming BESS in particular, this highlights that their system-strength value will be determined not only by voltage and frequency support, but by the extent to which their fault-current magnitude, sequence behaviour, and phase coherence are explicitly specified, validated, and coordinated with protection systems.

Finally, industry feedback gathered through OEM engagements reveals a consistent message: while GFM-BESS offer substantial benefits for voltage stability, synthetic inertia, FFR and hosting-capacity uplift, their fault-current contribution remains a critical limitation requiring careful design, tuning and validation. Solutions being explored include current-boost enhancements, inverter oversizing, and HIL-based verification of legacy protection schemes, especially in areas transitioning rapidly to high DER penetration. Standardising fault-current performance requirements, negative-sequence injection criteria, and GFM-specific access standards represents a major opportunity to ensure that these devices can be reliably integrated into future power systems and effectively support protection systems in 100% renewable grid scenarios.

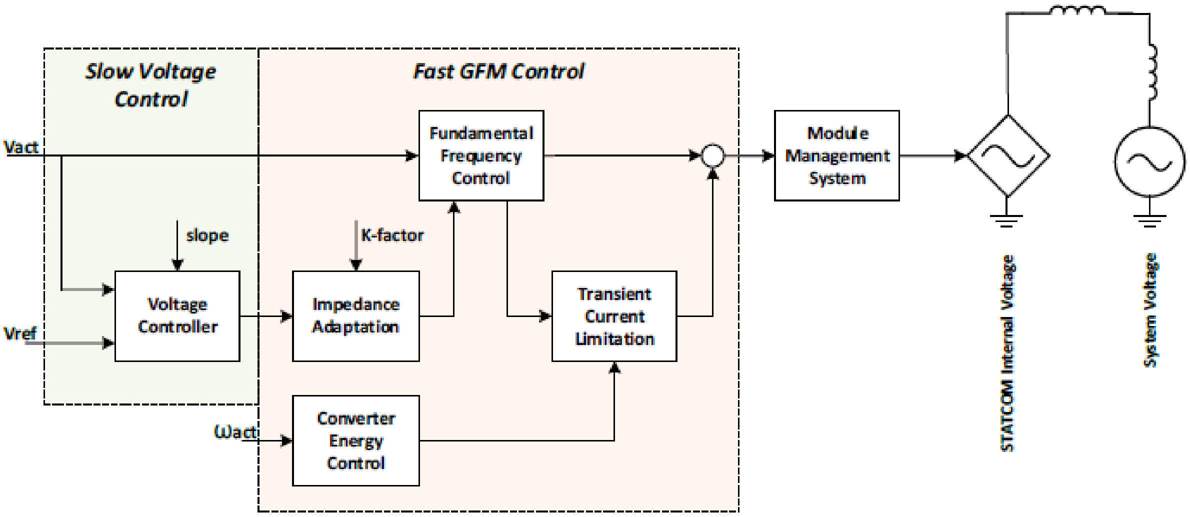
7.3 Grid-Forming STATCOM (GFM - STATCOM)

Static synchronous compensators (STATCOMs) are deployed to provide dynamic reactive power support. Historically, STATCOMs have relied on GFL control strategies, which use a phase-locked loop to inject current based on the grid's existing voltage and frequency. However, GFL STATCOMs face critical limitations: they suffer from reduced stability margins in extremely weak grids and lack the ability to support the grid independently during system restoration.

To overcome these deficiencies, the industry is transitioning toward GFM STATCOMs, recognising their potential to overcome the inherent limitations of GFL control. Industry adoption of technologies designed to operate with a GFM control strategy, has shown that such devices could provide substantial performance advantages even without injecting large amounts of active power into the AC network, especially during short disturbances. These observations suggest that adopting GFM control as the default mode for standard STATCOMs, even without additional storage, can materially improve performance in weak-grid environments. In GFM mode, the STATCOM operates similarly to an ideal voltage source behind an impedance providing near-instantaneous support during disturbances, such as voltage and angle changes. This results in lower transients during contingencies and increases transient stability during operation at extremely low short circuit levels, such as what may occur after critical contingencies or during network restoration. Thus, while a GFM STATCOM without additional energy storage cannot support frequency response, it can provide superior voltage support compared with a GFL STATCOM.

The defining feature of a GFM STATCOM is its fundamental shift in control paradigm. Rather than acting as a controlled current source delayed by a phase-locked loop, the device actively regulates the grid voltage. As illustrated in Figure 4, GFM STATCOM control relies on a fast-acting supervisory architecture incorporating (i) fundamental frequency control, (ii) virtual-impedance shaping, (iii) transient current limitation, and (iv) converter energy balancing, all coordinated beneath a slower outer-loop AC-voltage controller [23]. Together, these elements allow the STATCOM to deliver precise, immediate voltage-source behaviour.

Figure 4 – Simplified Block Diagram of GFM STATCOM Controller [23]



The fast-acting GFM control architecture consists of four control elements:

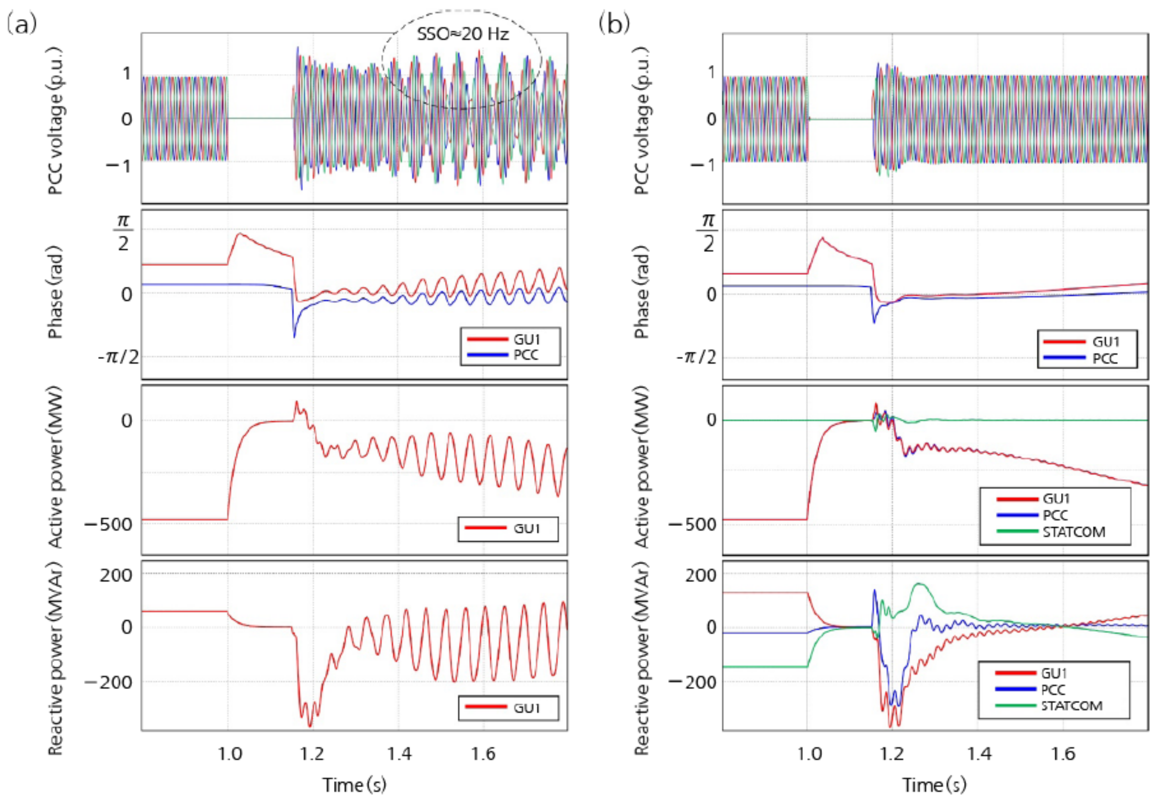
1. Fundamental Frequency Control: Detects changes in the AC voltage and directly outputs a voltage to counter the initial grid disturbance.
2. Impedance Adaptation: Modifies the apparent internal impedance to achieve an instantaneous inherent output response. The virtual impedance (Z) has two components i.e. virtual resistance (R) and virtual reactance (X). The virtual reactance dictates grid strength and voltage support, while the virtual resistance provides crucial transient damping.
3. Converter Energy Control: Balances the internal energy of the submodules to ensure safe converter operation during transients.
4. Transient Current Limitation: Acts rapidly to prevent semiconductor valve overcurrents if a disturbance commands an output that exceeds the converter's physical capability.

The advantages of GFM STATCOMs become particularly evident in weak networks dominated by IBRs. For example, studies for the ±300 Mvar Riverton STATCOM demonstrated stable GFM operation across network strengths varying from a strong 6,000 MVA down to an abnormally weak 390 MVA (an SCR of 1.3) [23]. Under severe disturbances, a GFL STATCOM often responds too aggressively, causing severe voltage oscillations that require stability controllers to actively reduce gains. In stark contrast, the GFM STATCOM's response is driven by its inherent voltage-source behaviour stabilising the network voltage almost instantly upon fault clearing without requiring parameter changes.

Further, weak grids with long AC cable connections are highly susceptible to subsynchronous oscillations (SSOs), which can be amplified by GFL controls or the physical inertia of synchronous condensers.

While synchronous machines can exhibit sub-synchronous resonance (SSR) at low frequencies at frequencies around 2-3 Hz, GFM STATCOMs are designed to smoothly provide power damping for the SSR and avoid resonances at low frequencies. By dynamically utilising its virtual resistance, the GFM STATCOM instantaneously reacts to voltage and phase angle changes, injecting positive active power damping to suppress SSOs effectively as also demonstrated in Figure 5 where it successfully suppresses an undamped ~20 Hz oscillation present when compensator is connected.

Figure 5 – Simulation Results in a Weak Grid with (a) No Compensation, (b) GFM STATCOM Connected [24]



Another key feature of GFM STATCOM is its superior handling of DC offset phenomena during asymmetrical faults or sudden phase angle jumps. Traditional synchronous condensers inject fault current accompanied by a high, slowly decaying DC component, which delays current zero-crossings and causes severe mechanical wear on circuit breakers. In contrast, GFM STATCOMs effectively damp these DC components by incorporating fictitious losses or virtual resistance into their control algorithms, rapidly eliminating the DC offset and protecting grid infrastructure and improving post fault recovery.

Despite these advantages, the fault current behaviour of a GFM STATCOM differs fundamentally from that of a traditional rotating machine. Synchronous condensers are known for their massive, inherent fault current capabilities typically 3.0 to 4.0 per unit (p.u.), driven by their physical sub-transient reactance. Conversely, the fault current contribution of a GFM STATCOM is strictly limited by the thermal overload ratings of its semiconductor valves. While a GFM STATCOM provides a highly controlled, instantaneous reactive current injection to arrest a voltage drop, it cannot naturally supply the massive peak currents of a synchronous machine unless it is deliberately oversized with overcurrent-rated semiconductors and has a significant cost impact.

Globally, GFM STATCOMs are gaining immense momentum, particularly among Transmission System Operators (TSOs). By 2025, the global footprint of GFM STATCOMs surpassed 10,000 MVAr, with over 20 installations in service [25].

Utilities are attracted by the substantial lifecycle and operational advantages over synchronous condensers: significantly lower losses, a smaller physical footprint, minimal mechanical maintenance, and a symmetrical reactive range, in contrast to the asymmetrical characteristics of rotating condensers.

Despite their superior dynamic capabilities and to a lesser extent their fault contribution capability, the widespread adoption of GFM STATCOMs faces critical engineering hurdles. Foremost is the absence of industry-agreed performance metrics or standardised testing guidelines for GFM controls. Traditional performance criteria used for GFL STATCOMs, such as step response time, overshoot, and settling time are not directly applicable to the instantaneous, non-linear inherent response of GFM algorithms. This gap forces engineers to rely on ad-hoc preparatory tuning solutions focused on specific parameters, such as the k-factor, which defines reactive current output relative to voltage deviation. Studies indicate that a k-factor of 12 enables full reactive power injection at approximately 8.3% voltage deviation [23] demonstrating that careful tuning can significantly enhance voltage support in weak-grid conditions.

Furthermore, validation of a GFM STATCOM requires extensive EMT simulations since phasor-domain simulation tools cannot capture the sub-cycle transient behaviours of power electronic interactions. Compounding this, OEM control algorithms are typically proprietary, limiting utilities to perform comparative studies using detailed models creating dependence on vendor supplied models. This enforces the need for EMT design, robust test frameworks, and eventual development of shared performance benchmarks.

In summary, the GFM STATCOM represents a critical evolution in power system compensation technology. By actively behaving as an internal voltage source behind a virtual impedance, it inherently solves the stability limitations of traditional grid-following devices in weak and renewable-heavy networks. While the technology cannot inherently match the large raw short-circuit current of a traditional synchronous condenser without expensive physical oversizing, the GFM STATCOM provides superior performance in damping sub-synchronous oscillations, mitigating DC fault components, and recovering network voltage seamlessly across a broad range of short-circuit levels. To fully unlock its system strength and protection benefits, the industry must urgently address the standardisation gaps, develop universally accepted performance metrics and establish robust EMT modelling frameworks.

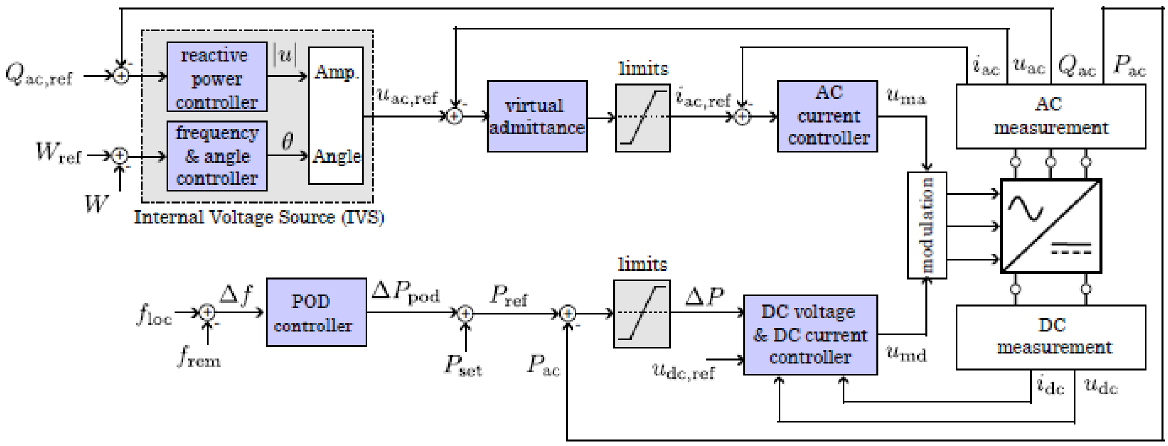
7.4 Grid-forming HVDC (VSC) Converters

HVDC transmission systems utilising voltage source converters (VSC) are critical assets in modern power systems as the energy transition accelerates. They enable the bulk transport of power over long distances and facilitate the integration of offshore wind and remote renewable generation. Traditionally, however, VSC-HVDC systems have predominantly relied on GFL control strategies. As outlined earlier as well, GFL technologies use a PLL to track the grid's voltage angle and inject current accordingly.

In weak grids, characterised by low SCR, the dynamic coupling between the PLL and the grid impedance can trigger severe control instabilities and amplify voltage disturbances. The impacts can be greater if the size of the converters is typically 0.5 GW – 2 GW and beyond.

These limitations have prompted OEMs and TSOs to transition toward GFM control for HVDC applications. The fundamental difference between GFL and GFM HVDC converters lies in their control paradigm: a GFM converter does not rely on a PLL to follow the grid; instead, it utilises internal control algorithms such as VSM or DC-voltage matching controls to self-synchronize. It acts as an ideal AC voltage source behind a virtual impedance, independently setting the frequency and voltage amplitude at the PCC. The generic GFM HVDC control architecture illustrated in Figure 6 illustrates internal voltage source generation, virtual impedance loop, and current limiters superimposed with outer power and DC voltage controllers.

Figure 6 – Simplified grid-forming control structure for HVDC applications illustrating the key components [26].

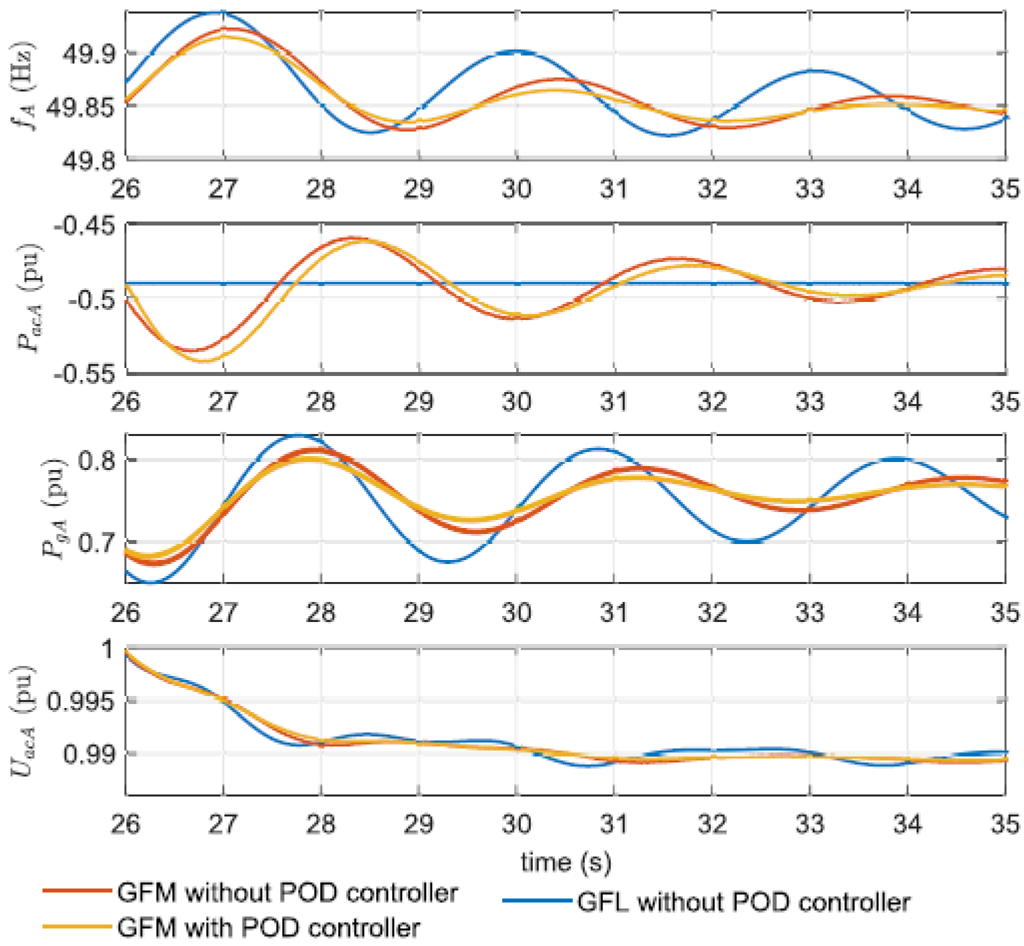


Although the control philosophy illustrated above mimics the behaviour of a synchronous machine, the physical reality of an HVDC link introduces a critical constraint: energy storage within the converter is limited by the export capability at the other (sending) end and HVDC station stores only a small amount of electrostatic energy in its DC capacitors. As a result, it may not be able to independently sustain the large, prolonged active-power injections needed for synthetic inertia without adversely impacting the AC network which the remote converter terminal is connected to.

Despite the energy constraints, a GFM HVDC converter can provide substantial benefits to system strength, particularly regarding voltage stiffness and the damping of grid oscillations. Their instantaneous reactive power response, which is independent of the remote DC cable or converter/AC network, greatly improves the voltage stiffness of weak AC grids allowing them to counteract disturbances more rapidly than GFL converters. Any sudden change in grid voltage magnitude or phase at the PCC is immediately offset by a proportional reactive and/or active power response. Comparative network studies demonstrate this behaviour clearly where parallel transmission lines were tripped (reducing the SCR from 3.0 to 1.3), and the traditional GFL HVDC links became unstable, whereas HVDC links equipped with GFM control, seamlessly maintained stability across the impedance jump [27].

Further, large, interconnected power systems often experience low-frequency electromechanical oscillations (e.g., 0.1 to 2 Hz). Traditionally, GFL HVDC converters required highly complex, dedicated power oscillation damping (POD) controllers to counteract these frequencies, which were often difficult to tune properly without highly accurate, wide-area network models. In contrast, GFM VSC converters inherently damp electromechanical oscillations due to their voltage source dynamics. This inherent POD capability stems from its natural opposition to positive RoCoF, achieved by decreasing active power injection without the need for external communications or complex parameter tuning. Figure 7 compares a GFL VSC converter (which fails to damp the 0.3 Hz oscillation) with a GFM VSC converter that suppresses the oscillation immediately following a fault.

Figure 7 – Comparison of POD with GFL and GFM Voltage Source Converters [26].



While GFM VSC systems drastically improve steady-state and dynamic system strength, their behaviour during severe short-circuit faults presents significant engineering challenges for legacy protection systems. Like all other GFM technologies discussed so far, GFM converters are physically constrained by the thermal limits of their power electronics (such as IGBTs). A HVDC converter can typically provide slightly above its nominal rating before activating transient current limiters to protect the power electronics. This limited fault current capability has implications for protection pick-up and coordination.

Like in other GFM technologies, the challenge is further exacerbated during asymmetrical (unbalanced) faults, which require reliable negative sequence current injection for directional and distance relays to operate correctly. In a VSC system, negative-sequence injection is governed entirely by the converter's software limits and current-priority logic. Because negative-sequence current consumes part of the converter's total current headroom, injecting too much may reduce the available positive-sequence current needed to support AC-grid stability. This creates a protection-stability trade-off unique to inverter-based HVDC.

An additional industry issue relates to the regulatory treatment of HVDC systems. Because HVDC utilises the same inverter technology as wind and solar farms, system planners often default to applying generic IBR generation grid codes to HVDC projects. This is fundamentally flawed because an HVDC system is a transmission asset whose primary purpose is network support and bulk power routing, not simply steady-state generation. HVDC and STATCOM facilities are meant to transmit and/or support the transmission network, however the included dynamic support capabilities are not useful if they block or trip when the system still has a chance of recovery. By holding all generation and transmission assets to the same standards it can cause improper coordination [28]. Applying strict, generation-focused voltage and frequency ride-through bounds can force an HVDC link to trip unnecessarily to protect itself, depriving the broader transmission network of a major source of planned stability during a cascading event.

As GFM HVDC deployment expands, two primary deployment challenges must also be specifically addressed: the complexity of dual-ended GFM operation and the necessity for standardised analytical modelling. Historically, if an HVDC link utilised GFM, it was only applied to one side (e.g., feeding a weak island grid), while the other side operated in GFL mode to securely manage the DC-link voltage. However, this is changing and projects like the Celtic HVDC link between France and Ireland are being designed with GFM on both sides [27]. Operating GFM on both converters is technically challenging because a frequency event at one end triggers immediate inertial active power into the AC grid draining the DC-link capacitor. The opposite end must simultaneously detect the DC voltage drop and extract active power from its connected grid to compensate. Balancing these competing control objectives, maintaining AC grid-forming requirements, while strictly prioritising DC voltage survival, often means the dynamic performance (such as inertial support) must be deliberately detuned or dampened compared to a single-sided GFM deployment.

The second challenge concerns modelling transparency and validation. Utilities often rely on vendor-supplied EMT models, which are "black-boxed", computationally heavy and offer limited insight into internal control dynamics. A promising approach is the development of analytical response envelopes based on quasi-stationary models [27]. These envelopes define upper and lower bounds for a converter's active-power response to phase jumps, allowing utilities to confirm whether a HVDC link demonstrates the expected "voltage-source-behind-impedance" behaviour without extensive trial-and-error EMT simulations.

Overall, grid-forming VSC-HVDC is a vital technology for maintaining system strength in future decarbonized power grids. By inherently providing sub-synchronous oscillation damping, near-instantaneous phase support, and synthetic inertia, GFM HVDC effectively neutralises the instabilities associated with traditional phase-locked loop tracking in weak networks.

A key point of differentiation compared with other grid-forming technologies is scale: modern HVDC converters are often among the largest single power-electronic devices connected to a network, with ratings commonly in the hundreds of megawatts (MW) and, in some cases, approaching or exceeding gigawatt scale (for example, projects such as Marinus Link at approximately 750 MW). As a result, their dynamic response can have a materially greater system-wide impact than smaller grid-forming inverters, such as those deployed within individual BESS installations.

However, successfully deploying these systems requires acknowledging their physical limits: they are current constrained during faults and possess virtually no internal energy buffer. Consequently, grid codes must be carefully adapted to treat HVDC as resilient transmission assets rather than generic generators, and advanced control coordination must be perfected to allow stable, dual-ended GFM operation across interconnected power systems.

7.5 Enhanced-STATCOM (E-STATCOM):

Traditional STATCOMs have long been used to provide dynamic reactive power for voltage support; however, their lack of physical energy storage has fundamentally limited their capability. Without stored energy, a standard STATCOM cannot independently arrest frequency drops or provide synthetic inertia during major disturbances; its contribution is therefore limited to reactive current injection and voltage support, relying on other system resources to supply active power and frequency stabilisation. To bridge this critical gap, industry has developed the E-STATCOM, also known as the Second-Generation STATCOM. Defined in [28] as *"A STATCOM that incorporates energy storage to provide a fast frequency response",* the E-STATCOM represents a major technological advancement, enabling the device not only to stabilise voltage but also to rapidly shape grid frequency and supply short, high-power active-energy injections essential for replacing the stabilising effects once supplied by synchronous machines.

A defining feature of an E-STATCOM is the integration of short-term energy storage with advanced GFM control. Unlike long-duration battery systems designed for energy-intensive applications, the E-STATCOM is specifically intended for power-intensive operation delivering extremely high active-power bursts over seconds rather than hours, creating synthetic inertia. For this reason, supercapacitors (SCs) are the current preferred storage medium in E-STATCOM as they tolerate fast cycling, offer exceptionally high power density, and respond on millisecond timescales.

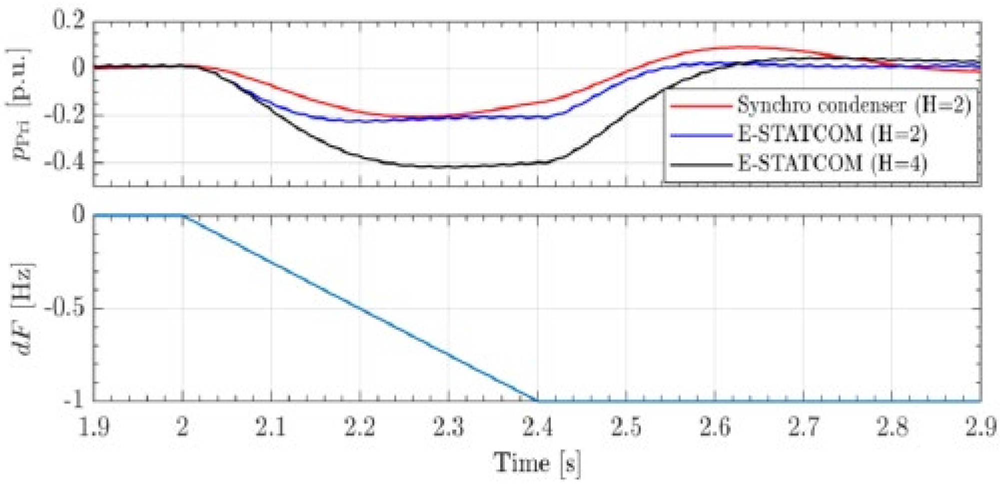
The most commonly referenced architecture in industry for E-STATCOM is the Cascaded H-Bridge (CHB) Multilevel Converter, which distributes the energy storage across the phases of the converter. Each power-module level contains three core components [29]:

- H-Bridge Inverter: Handles the final DC-to-AC conversion to interface with the grid. Supercapacitor Assembly: A stackable module containing SC cells (often Electrolytic Double Layer Capacitors) that provide the raw active power. DC/DC Converter: DC/DC converter decouples the SC from the H-bridge, allowing the system to extract maximum energy while maintaining a stable voltage for AC generation.

By storing electro-chemical energy directly within the converter legs, the E-STATCOM control algorithm can effectively emulate the mechanical equations of a rotating machine, acting as a VSM with highly tuneable inertia.

The above architecture enables the E-STATCOM to deliver a set of dynamic services that match and, in many cases, exceed, the capabilities of traditional synchronous condensers (SynCons). During a severe grid event, such as the sudden loss of a generator, the grid frequency drops rapidly. A traditional SynCon resists this change using its physical rotating mass. However, the energy exchange is constrained by physics (page 6): "only around 5% to 10% of the machine rating is used for energy exchange" [25] before the machine risks losing synchronism and tripping. By contrast, the E-STATCOM is fully controllable and can instantaneously release 50–200 MW of active power within milliseconds, utilising all the stored energy for inertia response rather than relying on natural physics. Consequently, a single E-STATCOM can replicate the inertial contribution of several large rotating machines. One other notable superior performance is illustrated in Figure 8 where the E-STATCOM not only sustains active-power injection for significantly longer than a SynCon under RoCoF event, but its flexible tuneable inertia constant ('H') allows adaptation to different grid-strength levels compared to Syncon.

Figure 8 – Power response comparison of a Synchronous Condenser and E-STATCOM under RoCoF event and tuneable inertia constant [25].



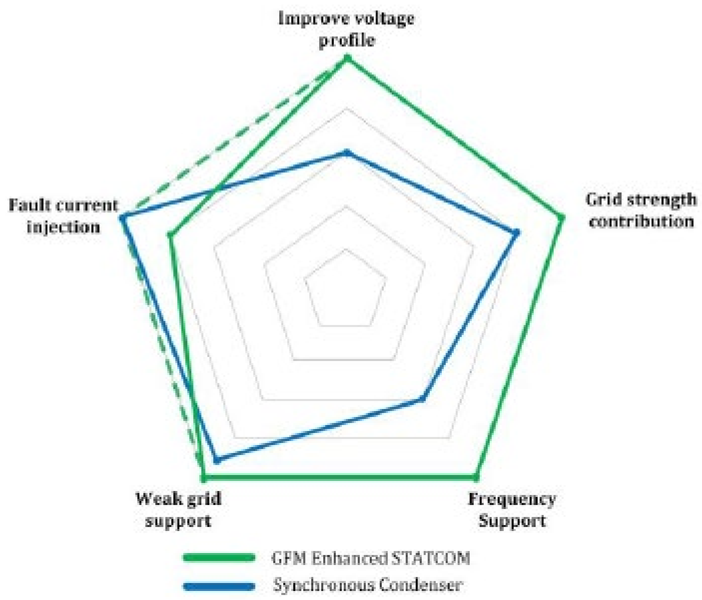
Further, traditional SynCons and transformers inherently generate high, slowly decaying DC components. This DC offset prevents the fault current from crossing zero smoothly, leading to delayed breaker operation and severe equipment wear. E-STATCOMs are specifically designed to incorporate fictitious losses (virtual resistance) to rapidly damp these DC components, protecting surrounding grid infrastructure.

Despite the above-mentioned advantages, the E-STATCOM's fault-current capability differs from that of a traditional SynCon. As noted earlier, SynCons naturally produce high fault currents due to their very low sub-transient reactance. Semiconductor-based converters, however, are thermally constrained: the E-STATCOM generally delivers fault currents only slightly above its rated current unless significantly oversized, which would impose substantial capital cost. While this controlled current is effective for stabilising voltage dips, its limited magnitude necessitates careful coordination with protection schemes originally designed around high-current synchronous behaviour.

For unbalanced faults (e.g., single-phase-to-ground faults), an E-STATCOM must also safely provide negative-sequence current. Its modular multi-level topology effectively supports this, exhibiting symmetric impedance for both the positive and negative sequence components enabling the control system to dynamically balance phase voltages during the fault, a critical feature for transmission network security.

For TSOs, E-STATCOMs offer dramatic reductions in operational costs. A traditional SynCon suffers from high frictional and windage losses. E-STATCOMs feature exceptionally low power losses [25]. Because these devices spend the vast majority of their lifespan in a steady-state idling mode waiting for a grid disturbance, this efficiency translates to massive lifecycle savings. Additionally, the E-STATCOM requires a smaller physical footprint, as it completely avoids the heavy concrete foundations and lifting cranes required for synchronous rotors. Figure 9 illustrates the comparative performance between GFM E-STATCOMs and SynCons. The E-STATCOM shows vast superiority in weak grid support, frequency support, and control tunability, while the SynCon maintains an inherent advantage in raw fault current injection.

Figure 9 – Summary of Capabilities: GFM E-STATCOM Vs Synchronous Condensers [25]



Operationally, the shift from mechanical inertia to supercapacitor-based synthetic inertia brings notable benefits, but also unique lifecycle challenges. A primary deployment challenge unique to the E-STATCOM is managing the physical aging of the supercapacitors. Over the design life of the plant, SCs degrade [29]: their equivalent series resistance (ESR) can increase by up to 200%, and their capacitance drops. As the SC ages, it becomes physically harder to extract energy. To compensate, the internal DC/DC converters are forced to draw progressively higher currents to deliver the same net active power to the grid. System designers must meticulously calculate these "end of life" (EOL) characteristics during the initial procurement phase to ensure the E-STATCOM can still meet grid code requirements for inertia two decades after installation [29].

Because the E-STATCOM relies entirely on proprietary software algorithms to dictate its fault response, standard root mean square (RMS) simulation tools are inadequate for system planning. Integrating an E-STATCOM requires highly complex EMT modelling to ensure its current-limited fault signatures do not cause legacy distance or directional protection relays to mis-operate. Grid operators are increasingly reliant on HIL testing injecting simulated E-STATCOM fault waveforms directly into physical relays to validate grid security before deployment.

Overall, the E-STATCOM is a transformative technology tailored for the decarbonised power grid and support of the increasing penetration of IBRs. By coupling the rapid voltage control capabilities of a STATCOM with the short-term active power reserves of distributed supercapacitors, it can successfully emulate and out-perform the dynamic stability contributions of traditional rotating machines. Although its fault current injection is inherently constrained by semiconductor thermal limits, the E-STATCOM's superior ability to damp sub-synchronous oscillations, mitigate DC fault components, and instantaneously arrest frequency deviations makes it an important asset. As power systems transition toward 100% renewable generation, the effective deployment of E-STATCOMs combined with proper lifecycle management of SC modules and rigorous EMT-based protection validation will be central to maintaining a resilient, stable, and efficient grid.

7.6 LV Technologies

The rapid proliferation of DERs in LV networks has intensified challenges linked to over voltage, undervoltage, phase imbalance, harmonic distortion, and fast dynamic instability. As LV feeders were never designed for widespread two-way power flow or large clusters of power electronic devices, Distribution Network Service Providers (DNSPs) can now implement advanced, pole/ground mounted LV power electronic technologies rather than traditional augmentation to maintain system strength and ensure power quality. Australian made technologies such as Ecojoule's EcoVAR LV STATCOM and EcoSTORE LV BESS[5] provide targeted mitigation of IBR driven risks right at the distribution edge, where instability is most acute.

EcoVAR is an IP56 rated, pole mounted LV STATCOM delivering 40 kilo volt amperes reactive (kVAr) of three phase dynamic reactive power support to counteract rapid voltage fluctuations, improve stability, and correct phase imbalance. Its patented active power balancing capability dynamically redistributes real power between phases, reducing neutral currents, suppressing zero sequence effects, and stabilising feeders experiencing uneven single-phase PV and battery connections. Field deployments across Endeavour Energy, Ausgrid, AusNet and SA Power Networks demonstrate

[5] https://ecojoule.com/ecovar/

EcoVAR's proven ability to correct phase imbalance in real world suburban and rural networks, materially enhancing voltage compliance and DER hosting capacity. In parallel, the EcoSTORE provides 40 kVA of LV BESS capability on the same PCS platform, incorporating lithium-ion batteries and a dedicated DC/DC converter to enable fast active power injection, peak shaving, and local management of the ""Duck Curve by charging during midday solar surplus and discharging during the evening peak.

While neither EcoVAR nor EcoSTORE increases LV fault current, both technologies enhance local network strength by maintaining stable voltage during upstream disturbances, reducing IBR nuisance tripping, limiting protection mis-operations, and improving overall power quality resilience. Together, they deliver fast continuous voltage regulation, real time phase balance correction, and active power support tailored to address the increasingly complex risks introduced by IBRs at the LV level.

Despite the effectiveness of LV power-electronic devices, several research gaps remain. A broader literature review highlights the lack of LV-specific protection studies, particularly regarding how fast-acting devices interact with fuses, smart meters, and evolving DER protection philosophies under distorted or low-fault-current conditions. There is also limited research on coordinated volt-var and droop control between DNSP-owned LV devices and behind-the-meter inverters, risking oscillatory behaviour during high DER export. Finally, studies show that the optimal siting and coordinated operation of LV STATCOMs and BESS can significantly influence post-fault voltage recovery, yet systematic frameworks for planning multi-device deployments in LV feeders are still emerging. Addressing these gaps will be essential for scaling new technologies like EcoVAR, EcoSTORE, and other similar LV technologies as foundational system-strength assets in increasingly inverter-dominated grids.

7.7 Conclusion

Across transmission and distribution levels, the technologies assessed in this report collectively demonstrate how modern power-electronic and grid-forming solutions are evolving to address the fundamental challenges introduced by high penetrations of IBRs. As synchronous generators retire, the power system is increasingly required to operate with reduced fault levels, weaker short-circuit strength, greater dynamic variability, and more complex non-linear control interactions, all occurring within a network whose topology and operating states change more rapidly than in the synchronous-machine era. These conditions directly affect the system's ability to maintain stable voltage, robust frequency, and dependable protection performance, necessitating a re-examination of the tools used to provide essential system-strength services.

The new technologies discussed in this report represent a generational shift in how stability and protection systems might be impacted as the synchronous machines retire and uptake of IBRs increases. Unlike grid-following devices, some of these solutions behave as controlled voltage sources capable of contributing synthetic inertia, fast frequency support, oscillation damping, and angle stabilisation in weak-grid environments where traditional control modes struggle. Although inherently current-limited, their advanced control systems provide rapid, precise, and tuneable responses during disturbances, demonstrating that system-strength support is no longer solely dependent on synchronous machines. At the same time, LV technologies such as EcoVAR and EcoSTORE extend these capabilities to the low-voltage level, providing DNSPs with unprecedented tools for mitigating DER-driven voltage instability, phase imbalance, harmonic distortion, and localised protection risks right at the LV level. Together, these innovations show how system strength and related challenges can now be supported from both the transmission and distribution layers of the grid.

As the power system continues its transition toward high renewable penetration, these technologies will form the backbone of a stable and resilient, inverter-dominated grid. However, several challenges remain. Gaps in fault-current capability, negative-sequence behaviour, coordinated control, model transparency, and protection compatibility must be resolved through standard-setting and co-ordination, advanced EMT-based validation, and structured industry testing frameworks. At the LV level, further research is needed into protection interactions, coordinated DNSP - consumer inverter control, and optimal multi-device deployment strategies. Addressing these gaps will be essential to ensure that these technologies not only enhance system strength but do so in a manner that fully integrates with protection schemes, operational practices, and future power-system planning.

Ultimately, the technologies described in this section demonstrate both the urgency and the opportunity presented by the rise of IBRs. When deployed strategically and supported by robust analysis and standards, they provide a credible pathway to maintaining voltage stability, supporting fault detection, and managing fast dynamic behaviour in a future grid where conventional system-strength sources are scarce. These emerging solutions are not merely compensatory technologies; they are foundational elements of the next-generation power system.

8. Task 4 – Advanced Protection Strategies

8.1 Introduction

The protection of power systems with high penetrations of IBRs presents one of the most significant challenges in modern power engineering. Traditional protection philosophies rely heavily on the characteristics of synchronous generation — high fault current magnitudes, predictable current phase angles, and well-defined sequence components. As power systems evolve toward decarbonisation, these assumptions no longer hold true. Inverter-based systems contribute low fault currents that are dependent on control modes, DC-link energy, and protection settings, leading to operational behaviours unlike those of conventional machines.

Several studies illustrate how these behaviours affect legacy protection schemes. Schweitzer Engineering Laboratories (SEL) has investigated the performance of line current differential protection in IBR-dominated networks, noting that inverter current limiting, control dynamics, and waveform distortion can cause differential relays to misoperate or fail to detect faults [30], [31]. Chowdhury et al. [30] and related SEL conference papers [31] present case studies showing both over-tripping and under-tripping in 87L schemes when IBRs operate in current-source control (CSC). Similarly, NERC [32] and PNNL [33] reports emphasise that as the IBR share grows, short-circuit strength and system impedance change dynamically, undermining protection coordination and speed.

Beyond line differential schemes, the challenges extend to virtually all protection domains. Sandia National Laboratories, EPRI, and Siemens [34] conducted an extensive gap analysis on grid-forming inverter behaviour and noted that while synthetic fault current injection techniques can improve relay visibility, the transient response remains highly dependent on inverter control architecture. IEEE Power System Relaying and Control Committee (PSRC) [35] has identified that relay performance in weak grids, particularly in networks with mixed inverter and synchronous sources, remains an area requiring adaptive coordination logic and control-aware algorithms.

The evolving nature of IBR fault responses has also spurred significant academic research. Telukunta et al. [36] and Farkhani et al. [37] provide comprehensive reviews of IBR-related protection challenges, highlighting issues such as low fault current magnitudes, high impedance faults, and distorted waveforms containing DC offsets and harmonics. EPRI [38] further examine the role of negative-sequence current suppression, noting that many inverter controls limit negative-sequence components, thereby compromising directional protection elements that rely on these quantities. Akhavan-Rezai et al. [39] and Chowdhury et al. [30] both document practical differential protection mis-operations caused by unbalanced inverter fault responses.

Emerging solutions are beginning to address these problems. EPRI [40] and NREL [41] have investigated fault current contribution testing for grid-forming inverters, while Beikbabaei et al. [42] explored the use of ML to distinguish between inverter control transients and genuine faults. Other work by Li et al. [43] and Ventura et al. [44] explores the use of traveling-wave and data-driven protection approaches that operate independently of fault current magnitude, offering promising resilience in IBR-rich environments.

While much of the literature focuses on relays and adaptive protection, very limited attention has been given to conventional fuse protection under low fault-current conditions. A recent International Conference on Electricity Distribution (CIRED) 2023 study [45] notes that in IBR-rich microgrids, fault currents may be insufficient to operate standard fuses reliably, potentially resulting in persistent faults and coordination issues. This highlights a gap in both academic research and industry guidance, underscoring the need to evaluate not only relay-based schemes but also fuse-based protection in IBR-dominated networks.

These collective insights frame the need for a broader, system-level understanding of protection challenges in IBR-rich environments. The following sections introduce the primary technical issues observed across literature and field experience, identify solution pathways proposed by recent research, and highlight persisting gaps that merit deeper investigation.

8.2 Current Characteristics of IBRs

IBRs contribute fault currents in a manner fundamentally distinct from synchronous machines. Unlike a rotating machine, whose output impedance is largely physical and fixed, the effective impedance of an inverter, Z_{IBR}, is dynamic and control dependent.

In general, the fault current at the POC can be expressed as:

$$I_f(t) = \frac{V_{\text{prefault}}(t)}{Z_s + Z_f + Z_{\text{IBR}}(t)}$$ equation 1[6]

where $V_{\text{prefault}}$is the prefault voltage, $Z_s$is the upstream source impedance, $Z_f$is the fault impedance, and $Z_{\text{IBR}}(t)$is the time-varying apparent impedance of the inverter.

The inverter's response depends on its control type:

While GFL and GFM classifications provide a useful framework, fault response is also strongly influenced by the specific control implementation. Current-limiting strategies, active- and reactive-current prioritisation, sequence-current control functions, and fault ride-through (FRT) behaviour can significantly influence fault current magnitude, duration, phase-angle characteristics, and protection-relevant fault signatures. These behaviours are often vendor-specific and may vary with operating conditions and fault type, contributing to uncertainty in protection performance assessment.

GFL Inverters regulate current based on a phase-locked reference. Their fault current is governed by the inner current control loop, typically realized as a proportional-integral (PI) controller in the synchronous dq-frame:

$$I_{dq}(s) = \frac{K_p + K_i/s}{1 + sT_c}\,[V_{dq}^{*}(s) - Z_f(s)I_{dq}(s)], \mid I_{dq} \mid \leq I_{\text{max}}$$ equation 2[7]

where $K_p$and $K_i$are the current-loop gains, $T_c$is the control delay, and $Z_f(s)$includes filter and cross-coupling terms. The commanded current is limited by I_{max}, producing a time-varying apparent impedance. GFL inverters typically inject limited fault currents (~1.1–1.25 pu) that decay according to control bandwidth and saturation characteristics.

GFM Inverters regulate voltage and emulate synchronous-machine dynamics using voltage control loops, droop, and virtual impedance. Their fault current is determined by the terminal voltage deviation and droop characteristics:

$$V_{dq}(s) = \frac{K_{pv} + K_{iv}/s}{1 + sT_v}\,[V_{dq}^{\text{ref}}(s) - Z_v(s)I_{dq}(s)]$$ equation 3[8]

where $K_{pv}$and $K_{iv}$are voltage-loop gains, $T_v$is the control delay, and $Z_v(s)$is the virtual impedance. Fault currents are generally higher than the steady-state load but lower than synchronous machines, with magnitudes controlled by virtual impedance and droop settings, and decay as voltage is restored.

[6] Keller, J., et al. (2010), "Understanding Fault Characteristics of Inverter-Based Distributed Energy Resources", NREL/TP-5D00-47623.

[7] Liu, S., et al. (2017), "Short-Circuit Current Characteristics of Inverter-Interfaced Renewable Energy Generators", Sustainability, 9(9), 1581.

[8] Stanković, A., et al. (2022), *"Fault-Current Injection Strategies of Inverter-Based Generation"*, IEEE Transactions on Power Delivery, 37(1), 57–68.

Consequently, similar GFL or GFM technologies may exhibit materially different fault responses depending on their internal control architecture and current-limiting philosophy. This highlights the importance of standardised performance requirements and testing methodologies capable of characterising protection-relevant fault behaviour across different inverter technologies

Despite differences in control philosophy, both types can be captured by a dynamic, time- and frequency-dependent apparent impedance model:

$$Z_{\text{IBR}}(s,t) = \frac{V_{dq}(s,t)}{I_{dq}(s,t)} \qquad \text{equation 4}[9]$$

This formulation provides a quantitative representation of inverter behaviour for short-circuit studies and protection analysis, highlighting the departure from classical impedance-based assumptions used for synchronous machines.

The dynamic and control-dependent nature of inverter fault currents, combined with their limited magnitude relative to synchronous sources, introduces a range of challenges for traditional protection schemes. Classical assumptions regarding fault current magnitudes, phase relationships, and impedance no longer hold, creating potential risks for relay mis-operation, delayed tripping, or failure to detect faults. These characteristics form the foundation for the protection challenges discussed in the following subsections, which examine overcurrent, distance, differential, harmonic-sensitive, and other relay types affected by high penetrations of inverter-based resources.

8.2.1 Protection Solutions for Low-Magnitude, Short-Duration Faults

The limited magnitude and short duration of fault currents from IBRs pose a fundamental challenge to traditional overcurrent protection schemes. Conventional relays, designed under the assumption of sustained fault currents from synchronous generators, may fail to detect faults or operate with unacceptable delay in IBR-rich networks [46], [46], [47], [48], [44]. To address these challenges, several mitigation strategies have been investigated in the literature.

One approach involves adaptive or grouped relay settings, where relays are configured with multiple setting profiles corresponding to the expected fault current contributions from connected IBRs [39], [47], [48], [44]. Communications or digital inputs are required to select the appropriate setting group dynamically, allowing relays to maintain sensitivity even when local fault currents are low. Such solutions rely on the availability of reliable coordination data, and careful selection of thresholds is essential to avoid nuisance tripping from load switching or inrush currents.

Another line of research emphasizes the enhancement of relay sensitivity and timing characteristics. By adjusting pickup levels and integration times, relays can detect brief fault events that would otherwise be missed [39], [47], [48]. This is particularly effective when combined with accurate modelling of the network and inverter behaviour to determine minimum expected fault currents

[9] IEEE Std 1547-2018, “Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces”.

across operating scenarios. However, care must be taken to maintain selectivity and coordination with downstream devices.

The incorporation of negative-sequence and zero-sequence considerations has also been shown to improve protection dependability. As IBRs—particularly full converter-based units such as Type 4 wind turbine generators—may partially or fully suppress negative-sequence currents, traditional overcurrent elements relying on these components can misoperate [33], [40], [49]. Standardizing negative-sequence injection through grid codes, as exemplified in IEEE 2800-2022 or VDE-AR-N 4120/4130, ensures that relays observe sufficient fault current under unbalanced conditions. In the Australian context, where prescriptive requirements are currently absent, this represents a notable gap that may affect relay coordination and reliability.

Finally, communication-assisted or supplementary protection schemes have been proposed, leveraging SCADA or IEC 61850 messaging to trigger relay operation when local currents are insufficient [39], [47], [35].

While such schemes can compensate for low-magnitude faults, they introduce additional complexity and dependency on communications infrastructure, which must be robust to maintain system security.

Despite these strategies, significant research gaps remain. Real-time adaptive protection frameworks capable of operating reliably in networks with mixed grid-following and grid-forming IBRs are limited, and studies on the long-term reliability of relay coordination under variable IBR output are scarce [47], [35], [48], [44] Furthermore, integration with legacy relays and devices in Australian networks, along with the lack of harmonized negative- and zero-sequence current requirements in local grid codes, underscores the need for focused research to maintain protection dependability as IBR penetration increases.

Taken together, these findings highlight a spectrum of mitigation measures—from setting adjustments and sensitivity enhancements to communications-assisted schemes—that can improve traditional overcurrent protection in IBR-rich networks. At the same time, they reveal a critical need for updated grid code requirements and further experimental and simulation studies to address gaps in understanding, particularly for mixed-generation systems typical of the Australian context.

8.3 Traveling-Wave Protection

TW protection operates on the principle of detection the high-frequency transients launched at the instant a fault occurs and measures their arrival times at different line terminals. These waves propagate at nearly the speed of light, enabling highly accurate fault-location estimates that do not depend on fault-current magnitude. In SEL's implementation, the double-ended TW fault-location algorithm uses the ratio of the measured TW arrival-time difference to the calibrated line propagation time.

$$FL = \frac{LL}{2} \times \left(\frac{\Delta t}{TWLPT}\right) \qquad \text{equation 5}$$

Where:

FL is the fault location (the distance from the local terminal to the fault),

LL is the line length (the total physical length of the protected line),

Δt is the time difference between arrival times $(t_{remote} - t_{local})$, and

TWLPT is the traveling-wave line propagation time (the time it takes for a wave to travel the entire line length.

TW-based methods routinely achieve location accuracy within a single tower span; significantly outperforming the 1–2% accuracy typical of impedance-based schemes—and can operate in the sub-millisecond range. Field deployments have demonstrated TW directional elements operating within around 100–200 µs, with fault-location reporting available in under 60 ms.

This performance offers a compelling solution to the protection challenges emerging in IBR–rich networks, where traditional impedance- and sequence-based algorithms can be adversely affected by low, controlled, or distorted fault currents [41].

Numerous TW protection and fault-location installations have been successfully deployed across Australian transmission networks. Australian Energy Regulator recognises the operational reliability benefits of TW technologies, noting that *"Travelling-wave fault location provides improved accuracy of faults on the network compared to distance-to-fault measurements from protection relays… [resulting in] reduced patrol and fault location times, quicker commencement of repairs for sustained faults, and improved network capability through reduced duration of unplanned outages."* [10]

Schweitzer Engineering Laboratories highlights that transient-based protection algorithms operating directly in the time domain provide a practical means of addressing protection challenges in IBR-dominated networks. These algorithms use high-speed sampling to detect incremental changes in voltage and current at the instant a disturbance occurs. Because Travelling waves propagate at close to the speed of light, fault detection can occur before inverter control responses influence conventional phasor measurements. TW based protection is implemented in commercial relay platforms and includes applications such as TW differential protection, directional protection, and high-speed fault location. [50]

However, despite its strengths, the technology carries practical limitations that constrain where it can be effectively deployed. TW relays perform best on long overhead transmission lines and HVDC corridors, where high-frequency transients propagate cleanly and can be accurately timed between terminals. Their independence from fault-current magnitude makes them particularly advantageous in weak or heavily inverter-dominated systems. Yet performance degrades on short lines, mixed overhead–cable circuits, or distribution feeders, where attenuation and reflections can obscure the initial wavefront. Deployment also requires precise GPS time synchronisation, high-bandwidth

[10] TransGrid, Network Capability Incentive Project Action Plan 2014/15–2017/18, Appendix A: Travelling-wave Fault Location Benefits, Australian Energy Regulator (AER) submission, January 31, 2014.

sampling, robust telecommunications, and specialised commissioning tools. Consequently, TW elements are typically integrated alongside conventional protection to maintain redundancy and overall scheme dependability.

Although traveling-wave protection is inherently well-suited for IBR-rich networks—since it relies on high-frequency fault transients rather than fault-current magnitude—the detailed behaviour of traveling waves in networks dominated by inverter-based resources under all operating conditions remains an active research area. Several factors can influence performance: different converter control strategies may alter the characteristics of the initial transient potentially affecting the travelling-wave signatures used for fault detection, location and directional discrimination. Network topologies with short lines, cables, or mixed overhead–underground sections can affect wave propagation and reflections; and noise immunity and filtering in highly dynamic, IBR-rich grids remain areas requiring refinement.

Further research addressing these complexities, along with the development of standardized testing, commissioning procedures, and guidelines for integrating TW protection with conventional schemes, is essential to enable reliable deployment in sub-transmission and plant-level protection zones as grids transition to high levels of renewable and inverter-based resources.

8.4 Directionality and Weak-Grid Impacts

Directional protection elements rely on stable and predictable phase relationships between voltage and current to determine fault direction. In IBR-dominated and weak-grid systems, these assumptions can be compromised due to limited fault current magnitude, altered negative-sequence injection, and control-driven phase angle behaviour.

In traditional systems, negative-sequence voltage–current relationships provide robust directional discrimination for unbalanced faults. However, as documented by EPRI [51]and IEEE PSRC [35], many grid-following inverters suppress negative-sequence currents to protect semiconductor devices. This suppression alters the expected phase angle relationships used by directional elements, potentially resulting in:

- Loss of directionality under low fault current conditions
- Incorrect forward/reverse declarations
- Reduced sensitivity in high-impedance faults
- Blinding of feeder relays in weak grid segments

In very weak systems, where short-circuit ratios (SCR) may fall below 2–3, voltage phase angle stability itself becomes uncertain during transients. Grid-forming inverters introduce additional complexity: their virtual impedance and droop controls may dynamically alter fault current phase angle in a manner not correlated to physical network impedance.

A generalized expression for directional torque in a negative-sequence element may be written as:

$$T_{dir} \propto R_e(V_2 I_2) \qquad \text{equation 6}$$

Where V_2 and I_2 represent negative-sequence phasors. When I_2 magnitude is limited or phase-controlled, T_{dir} may not achieve sufficient operating torque for secure tripping.

- Emerging mitigation strategies include:
- Cross-polarized directional elements
- Memory voltage polarization
- Adaptive directional thresholds based on SCR estimation
- Communication-assisted directional comparison

However, literature consensus indicates that directional performance in mixed GFL/GFM systems remains insufficiently validated through large-scale field testing [35].

Schweitzer Engineering Laboratories reports that conventional power-swing blocking schemes based on impedance blinders can become unreliable in low-inertia systems. In networks with high penetrations of inverter-based resources, power swings may evolve significantly faster than those associated with synchronous machine dynamics, causing traditional blinder-based detection methods to misclassify stable and unstable swings. To address this behaviour, protection algorithms have been developed that monitor the rate of change of apparent impedance rather than relying solely on fixed impedance blinder regions.

The algorithm dynamically evaluates the impedance trajectory to determine whether a swing is stable or unstable and whether distance protection should be blocked, removing the need for user-defined blinder settings [52].

In addition, increased background negative-sequence quantities arising from highly unbalanced DER and V2G penetration may further reduce the operating margins available to protection functions that rely on sequence-based measurements. Elevated and highly variable phase unbalance can increase the normal operating level of negative-sequence voltage and current seen by protection relays, potentially affecting the sensitivity and security of fault detection, directional discrimination, and phase-selection functions.

Research Gap: There is limited published validation of directional element stability in networks where inverter control modes dynamically switch between current limiting and voltage support during FRT events.

8.5 Differential and Advanced Protection

8.5.1 Differential Protection

IBRs typically limit their fault current contribution to 1–1.5 per unit, compared to 5–10 per unit from synchronous machines, due to power-electronic current-limiting controls. This significantly reduces the fault current imbalance normally used by differential protection, making detection more challenging. The traditional assumptions behind differential protection rely on the stable electromagnetic characteristics of synchronous machines [53].

In contrast, IBR fault behaviour is driven by control algorithms, meaning currents may follow artificial profiles rather than physical machine responses. This makes differential protection less predictable during faults. During disturbances, IBRs may transition between control modes or enter current-limiting regimes, causing the measured current to evolve rapidly. Differential relays, which depend on stability in the relative current measurements at protected terminals, may see a moving and inconsistent fault signature, complicating operation [53].

Because IBR apparent impedance changes based on voltage, control strategy, and system state, the underlying assumptions used by differential protection about stable current distribution no longer hold, particularly for line or transformer differential schemes [53].

Unlike synchronous machines, who's short-circuit behaviour depends on system impedance, IBR current output is strongly tied to terminal voltage. Differential protection, which relies on predictable current contributions from each terminal, may misinterpret these voltage-dependent current limits as external faults or fail to detect internal faults [53].

Differential protection remains fundamentally attractive in IBR-rich systems because it compares currents locally rather than relying on fault magnitude assumptions. However, as demonstrated in SEL case studies [30], [31] and by Akhavan-Rezai et al. [39] inverter control behaviour can introduce asymmetries that challenge classical differential algorithms.

Observed issues include:

- Differential current restraint miscalculation due to current limiting
- Harmonic content affecting percentage differential characteristics
- DC offsets and waveform distortion influencing phasor estimation
- Unequal transient responses between line terminals with different inverter mixes

Modern relays mitigate these effects through:

- Second- and fifth-harmonic blocking refinement
- Time-domain differential algorithms
- Adaptive slope characteristics
- Waveform-based differential elements

Time-domain differential approaches, in particular, avoid phasor estimation delays and may improve dependability under short-duration faults.

A generalized differential criterion may be expressed as:

$$|I_1 - I_2| > Slope \times \frac{(|I_1| + |I_2|)}{2} + Pickup \qquad \text{equation 7}$$

Where slope must now account for control-driven asymmetry rather than solely CT error and charging current.

Research Gap: Existing percentage-differential settings are largely derived from synchronous-source assumptions. Quantitative guidelines for slope and restraint optimization in IBR-dominated systems remain limited.

8.5.2 Rate-of-Change-of-Frequency Protection

Rate-of-Change-of-Frequency (ROCOF) protection has traditionally been applied for islanding detection, system separation schemes, and the identification of severe power system disturbances. In conventional synchronous-machine-dominated systems, large rotating inertia and relatively predictable voltage and frequency behaviour enable relay algorithms to derive stable frequency estimates following disturbances.

IBR dominated systems introduce new challenges for ROCOF-based protection. Unlike synchronous machines, inverters regulate output through fast-acting control systems that may modify voltage magnitude, phase angle, active power output, and reactive power injection during disturbances. Fault ride-through (FRT) functions, current-limiting strategies, and phase-locked-loop (PLL) dynamics can therefore influence the measured voltage waveform used by protection relays for frequency estimation.

Conventional ROCOF relays do not directly measure frequency; rather, they estimate frequency from the rate of change of voltage phase angle over time. During network disturbances, rapid phase-angle variations introduced by inverter controls can result in unstable or highly variable frequency estimates. To maintain security and avoid nuisance operation, frequency-estimation algorithms frequently employ filtering, averaging, and observation windows. While these techniques improve measurement stability, they may also increase operating times, introducing an engineering trade-off between protection speed, dependability, and system security.

These challenges become increasingly relevant in low-inertia and low-system-strength networks, where rapid identification of abnormal operating conditions is important to maintaining system security. The interaction between network topology, inverter control systems, fault ride-through strategies, and relay frequency-estimation algorithms remains an active area of research. Consequently, validation of ROCOF-based protection in IBR-rich networks increasingly relies on EMT simulation, hardware-in-the-loop (HIL) testing, and field trials capable of capturing sub-cycle inverter control behaviour that may not be represented adequately in conventional phasor-domain studies.

Research Gap: Limited publicly available guidance exists regarding suitable ROCOF settings, filtering requirements, and performance validation methodologies for networks with high penetrations of grid-following and grid-forming IBRs. Further research is required to establish consistent application criteria and performance expectations for ROCOF-based protection functions in low-inertia power systems.

8.5.3 Voltage-Based Fault Phase Selection

As fault current magnitudes reduce and negative-sequence current contributions become increasingly constrained by inverter control systems, conventional current-based fault phase selection techniques may experience reduced sensitivity and reliability. As a result, several protection manufacturers have investigated the use of voltage-based fault phase selection methods that utilise voltage depressions, negative-sequence voltage V_2, and zero-sequence voltage V_0 to identify faulted phases independently of current magnitude [49].

Unlike current-based approaches, voltage-based methods are inherently linked to the network voltage profile and may therefore remain effective where inverter fault current is heavily limited. A simplified negative-sequence phase selection criterion may be represented as [54]:

$$V_2 = \frac{1}{3}(V_a + a^2 V_b + aV_c) \qquad \text{equation 8}$$

Where V_a, V_b and V_c are phase voltages and $a = e^{j120^\circ}$.

Under asymmetric faults, negative-sequence and zero-sequence voltage components can provide clear indications of the faulted phase even when fault current contribution is low. For this reason, several manufacturers have proposed increased reliance on voltage-derived quantities for fault identification and directional supervision in weak-grid environments.

However, the approach introduces its own challenges. During close-in faults or severe voltage depressions, the voltage signals used for phase selection may collapse significantly, reducing measurement margins and potentially affecting fault classification. Similarly, in weak-grid conditions, inverter control actions associated with fault ride-through, reactive current support, and voltage regulation can influence the measured voltage waveform during disturbances. These control-driven interactions may affect the stability of voltage-derived protection quantities and require additional filtering, supervision or adaptive logic [55].

Recent technical reports by the IEEE Power System Relaying and Control (PSRC) Committee, EPRI, and NERC have identified the interaction between inverter controls and voltage-based protection functions as an emerging area requiring further validation, particularly under mixed grid-following and grid-forming operating conditions. While voltage-based approaches offer a potential alternative to conventional current-dependent methodologies, their performance across varying system strengths, inverter technologies and fault locations remains an active area of investigation.

Limited independently validated field data and standardised performance benchmarks exist regarding the behaviour of voltage-based fault phase selection schemes in highly inverter-dominated networks. Therefore, further research and industry-wide collaboration are required to address several key technical gaps:

- **Minimum Sensitivity and Operating Thresholds:** Investigation of relay directional security and phase-selection accuracy during close-in faults, where severe local voltage depression may reduce residual voltage signals below conventional measurement thresholds.
- **Control and Protection Co-Design:** Improved understanding of how inverter fault ride-through (FRT) functions, reactive current support, and other fast-acting control responses influence voltage-derived protection quantities, including the relay filtering, supervision, and logic requirements needed to maintain dependable operation.
- **Validation Under Mixed IBR Architectures:** Development of standardised EMT simulation models, Hardware-in-the-Loop (HIL) testing methodologies, and benchmark networks to quantify the performance and stability of voltage-derived protection quantities across varying

system strengths and combinations of grid-following (GFL) and grid-forming (GFM) technologies.

8.6 Industry Collaboration

Amplitude Consultants engaged with protection relay OEMs to obtain industry perspectives on protection challenges in networks with high penetration of inverter based resources. The engagement sought to identify how relay technology has evolved to address reduced fault currents, harmonic distortion, weak grid conditions, and sub-synchronous oscillations that characterise IBR dominated power systems.

Three protection relay OEMs participated in this industry collaboration: Schweitzer Engineering Laboratories, Hitachi Energy, and Schneider Electric. The engagement comprised a combination of structured questionnaires and direct technical interviews conducted between November and December 2025. This section presents a factual summary of each OEM engagement based solely on the information provided by the participating organisations.

8.6.1 Schweitzer Engineering Laboratories

Amplitude Consultants conducted a Microsoft Teams interview with Schweitzer Engineering Laboratories (SEL) on 14 November 2025. The discussion provided detailed insights into the company's approach to protection in IBR rich networks, covering transient based protection methodologies, secondary control systems, power swing detection algorithms, and sub synchronous oscillation mitigation strategies.

The company has developed protection algorithms that operate in the time domain rather than relying on conventional phasor estimation. These algorithms use high speed sampling at MHz scales to detect incremental changes in current and voltage at the point when a disturbance occurs, enabling fault detection before IBR fault response characteristics fully develop and thereby avoiding the complications associated with distorted current waveforms and limited fault current injection from inverters. Time domain algorithms have been implemented for differential protection, distance protection, and directional elements. These transient based relays are part of the current product line rather than pilot projects, with field deployments including transmission line protection applications in Brazil at 500 kV where the protection scheme uses both transient based and phasor-based elements for IBR integration.

Traveling wave-based protection is available as a commercial product offering, with applications including traveling wave differential protection, directional protection, and fault location. Because traveling waves propagate at close to the speed of light, fault detection can occur before the IBR's response affects conventional measurements. Traveling wave-based fault locator functionality is also offered as part of the product line.

The interview identified that conventional power swing blocking using blinder schemes can be unreliable in low inertia systems because IBR induced power swings are faster than those from synchronous machines. To address this, an algorithm has been developed that tracks the rate of change of impedance rather than relying on traditional blinder based detection. This algorithm requires no user settings and dynamically calculates whether a swing is stable or unstable to determine whether protection should be blocked.

A significant portion of the discussion addressed the PowerMax system, which operates as a secondary level controller above primary inverter and generator controllers. According to statements made during the interview, this system has been deployed in Australia since approximately 2010, with installations at Chevron's Gorgon and Wheatstone facilities and at Worsley Alumina in Western Australia. A recent project was also completed in New South Wales at approximately 5 MW scale. PowerMax provides functions including sub synchronous oscillation detection and damping, frequency management after primary controller response, load sharing coordination, and islanding detection with automatic mode switching for grid-forming capable batteries. The system can interface with various inverter controllers using standard protocols such as Modbus, though communication speed may present limitations for real time applications.

Metering products capable of point on wave sampling at 14 kHz have been developed for oscillation detection. A remedial action scheme approach was described, where, upon detecting an oscillation, the secondary controller can take remedial actions including isolating the oscillating device, modifying inverter setpoints, or implementing POD. Power oscillation damper functionality is under development for controller products. Internationally, remedial action schemes have been implemented in Brazil for transmission networks at 765 kV and 500 kV, including interface with HVDC links (Paulo Max Maciel Portugal, Renato Weingartner Pernas, Lucas Vernot Amaral, and Renata Ribeiro Silva, Furnas Centrais Eletricas S.A. Ricardo Abboud, Rafael Cernev, and Marcos Cabral, Schweitzer Engineering Laboratories, Inc., 2022).

When asked about achieving overcurrent coordination in networks with low fault levels, the recommendation was to move toward communication-based schemes rather than relying solely on magnitude and time grading. Where one side of a protection zone experiences weak infeed, the stronger side can detect the fault and use communication-based logic to send a trip or block signal, similar to echo schemes used in transmission protection. The company acknowledged that IBRs typically do not provide negative sequence current, which affects conventional protection schemes that rely on sequence component detection. Transient based protection addresses this limitation because the algorithms do not depend on negative sequence quantities, while differential protection remains viable for conventional schemes because it compares current magnitudes at zone boundaries rather than relying on sequence components.

Regarding transformer differential protection and harmonic restraint, the relays use filtering to extract fundamental frequency components from distorted waveforms. Conventional harmonic blocking and restraint settings are still applied, though adjustment may be required where IBR harmonic signatures overlap with transformer inrush characteristics. No new innovations specifically addressing this issue were immediately identifiable.

The company is not currently using artificial intelligence for protection tripping decisions, characterising the industry as being far from trusting AI based algorithms for that purpose. AI applications are being explored for higher level functions including predictive analytics, wide area monitoring visualisation through Synchrowave Operations software, and energy management applications. Incipient fault detection using digital signal processing of current distortions was mentioned as an existing capability, though this was described as signal processing rather than artificial intelligence.

Technical papers available on the company website were referenced, including papers from the Western Protective Relaying Conference held in Spokane, Washington in October 2025 as forthcoming resources addressing IBR protection challenges. Interest was expressed in participating in future CSIRO industry research collaborations that may emerge from this research program.

8.6.2 Hitachi Energy

Hitachi Energy Grid Automation provided a written response to the technical questionnaire distributed by Amplitude Consultants. The response stated that the company has a significant installed base of protection relays for various applications in IBR connected systems and holds a number of patented algorithms with continuous improvement of protection functionality in their intelligent electronic devices (IEDs). All responses were stated to be based on experience with the installed base.

The questionnaire response stated that the IEDs have a wide range of settings for each protection application, with distance protection capable of being set as low as 5% of nominal current. Regarding handling of non-sinusoidal fault waveforms, patented algorithms are designed to handle various transient phenomena in the power system. The response noted that there are no international standards defining relay behaviour for negative sequence elements under IBR dominated conditions, stating that the relays are designed to handle negative sequence. Regarding directional element reliability under low short circuit ratio conditions, the company holds several patents in this area which are continuously piloted and then implemented in product releases.

For islanding detection, system solutions with ROCOF, underfrequency, and over-frequency protection can be deployed, though these solutions are very much power system dependent and cannot be directly compared on a one-to-one basis across different applications. In addition to advanced protections, the filters within the IED support frequency tracking to ensure robustness against false tripping from frequency swings.

Regarding differential protection, the questionnaire stated that patented model-based line differential protection has been developed specifically to handle connection to IBRs (Hitachi Energy questionnaire response, December 2025). For transformer differential protection with harmonic rich fault currents, the patented differential protection for transformers considers harmonics in the differential current rather than individual phase currents.

A patented double ended fault location algorithm has been developed specifically for IBR applications. For multi owner microgrid coordination, protection IED setting software can export to standard Extensible Relay Input/Output (XRIO) file format for interoperability with other OEMs.

On communications, line differential protection supports various communication media including direct fiber and communication network backbone. For GOOSE based protection, IEDs are designed for GOOSE messaging, and the communication system should be designed appropriately with specific access points for GOOSE messages.

Regarding cybersecurity, the questionnaire response stated that global sites, products, systems, and development cycles are certified to IEC 62443 4, IEC 62443 3 3, IEC 62443 4 1, and IEC 62443 4 2 (Hitachi Energy questionnaire response, December 2025).

The questionnaire stated that forward facing statements regarding future requirements, product roadmaps, or AI integration in protection products cannot be provided. Pilot deployments and R&D activities were stated to be subject to non-disclosure agreements with customers. However, publicly available publications addressing AI and grid modernisation were referenced, and the company indicated commitment to AI development within its operational space. Representation in relevant IEC and IEEE working groups was confirmed. Customised trainings are provided in collaboration with customers on specific protection requirements.

8.6.2.1 Schneider Electric

Schneider Electric provided a partial response to the questionnaire on 18 December 2025, addressing only questions relating to artificial intelligence integration, future technology roadmaps, and simulation capabilities. The respondent noted that the items commented upon were internally completed but not yet released, though close enough to release that information could be shared externally.

Regarding AI and ML based fault detection, the mid-range protection relay platform has recently implemented AI as part of the algorithm for DTEF detection (Schneider Electric questionnaire response, 18 December 2025). This function serves the same purpose as traditional steady state earth fault detection but uses transients at fault inception rather than steady state quantities. It is applicable in isolated or compensated power systems and operates for all kinds of earth faults including steady state, self-extinguishing, and intermittent faults.

The questionnaire response described the signal processing chain as follows: monitoring delta IN as a trigger, determination of direction using AI which also indicates its confidence level, checking VN for earth fault confirmation, outputting a start signal when VN exceeds the set threshold, and outputting the direction signal with operate and reset delay timing. The response explicitly characterised this implementation by stating that the implementation of AI in this instance is to assist conventional fault detection methods with specific tasks in the processing chain. When asked about AI, ML, and edge analytics integration more broadly, the DTEF implementation was referenced as an example of the company's approach.

Regarding simulation and training resources for protection engineers working with IBR scenarios, the high-end protection relay platform can be run in a virtual environment as a Digital Twin of the hardware-based device. The response stated that a Digital Twin virtual environment running real versions of devices is foreseen as the most accurate and achievable method of running complex operational models for systems analysis.

8.6.3 Summary

The three OEM engagements demonstrate that protection relay manufacturers are actively addressing the challenges presented by IBR dominated networks through a range of approaches. SEL has developed transient based and traveling wave protection algorithms that operate in the time domain to avoid dependencies on steady state fault characteristics, with commercial products deployed in transmission applications internationally. Hitachi Energy has developed patented model based differential protection and double ended fault location algorithms specifically designed for IBR connections, with recent firmware releases including renewables specific protection functions such as undervoltage ride through protection. Schneider Electric has implemented artificial intelligence within their earth fault detection algorithms as an assistive technology within the signal processing chain.

Common themes across the engagements include recognition that conventional phasor-based protection faces challenges in IBR environments, movement toward communication-based schemes where magnitude and time grading is insufficient, and cautious approaches to artificial intelligence where AI assists rather than replaces conventional protection logic. All three OEMs indicated ongoing development activity in this area, with varying willingness to disclose product roadmap information. Both Hitachi Energy and SEL confirmed participation in international standards working groups.

The industry engagement confirms that protection relay technology is evolving to address IBR integration challenges, though standardisation of approaches remains limited. The reliance on proprietary algorithms and patented methods indicates that network operators may face interoperability considerations when specifying protection systems for IBR dominated networks. The partial nature of the Schneider Electric response and the confidentiality constraints noted by Hitachi Energy regarding pilot deployments suggest that complete transparency on product development is not uniformly available from all OEMs.

9. Academic Research

The Australian academic sector is a critical partner in addressing the protection and stability challenges identified in this report. This chapter synthesises university research that is directly relevant to weak-grid operation, IBR-rich protection performance, DER/VPP orchestration, and compliance (including the detection issues pertinent to NER clause S5.2.5.10). The focus is twofold. First, it presents evidence-based insights from peer-reviewed publications, national demonstration programs, and laboratory/field testbeds. Second, it identifies practical collaboration pathways—including validation testbeds, data/model sharing, and pilot deployments—through which research outcomes can be translated into operational practice by NSPs, market bodies, OEMs, and CSIRO.

Engagements prioritised institutions with established capabilities in real-time digital simulation, HIL, distribution-to-transmission co-simulation, DER/VPP integration, grid-forming inverter control, weak-grid dynamics, and microgrid/remote system protection. The analysis integrates (i) literature review of academic outputs, (ii) structured discussions with researchers and lab managers, and (iii) examination of national knowledge-sharing programs. Where information was shared under confidentiality, findings are presented thematically and non-attributed. The guiding standard is that of scientific literature: sufficient detail is provided to enable, in principle, a professional peer to reproduce the activity and obtain substantively identical results, with procedural specifics and test artefacts referenced to the originating institutions' publications or included in appendices where available.

This chapter is organised into an overview of the national research landscape (Section 9.1), followed by institution-specific profiles (Section 9.2 onward). Each profile follows a common structure covering relevance, methodology (as synthesis), results, insights, collaboration pathways, and future work aligned to the 2021 AR-PST Roadmap, ensuring consistent comparison and facilitating programmatic collaboration.

9.1 Overview of the Australian Research Landscape

Australia's universities have invested substantially in the methods, testbeds, and evidence base required for secure operation of renewable-dominated power systems. Facilities commonly include RTDS, microgrid and HIL platforms, distribution-to-transmission co-simulation environments, and precinct-scale demonstrators. These infrastructures enable controller- and power-HIL validation of relays, inverters, and system-protection schemes; characterisation of weak-grid dynamics (including grid-forming/grid-following behaviour under faulted conditions); and evaluation of cyber-physical interactions prior to field deployment. The net effect is to shorten the translation cycle from concept to operational practice, while managing risk.

A distinctive feature of the Australian landscape is the coupling of technical experimentation with market and regulatory innovation. University-led work on DOEs, VPP orchestration, and microgrid regulatory frameworks has been advanced through AEMO/ARENA knowledge-sharing programs and regulatory sandboxing, ensuring that research on protection and stability is appraised alongside operational feasibility, consumer participation, and compliance considerations.

This coupling is especially pertinent to the challenges articulated as reduced fault levels, variable phase response and sequence-component behaviour of IBRs, harmonic/interharmonic distortion, and the compounding effects of weak-grid operation on protection measurements and coordination.

The subsections that follow synthesise capabilities and focus areas across selected institutions and highlight practical pathways for collaboration that can accelerate translation into field practice, with an emphasis on reproducibility, non-vendor-specific methods, and relevance to Australian operating conditions.

9.2 The University of Melbourne

9.2.1 Overview

The University of Melbourne (UoM) is a lead research partner in the AR-PST program, leading two of the nine core research topics. defined in the national roadmap. Research is primarily directed through the Melbourne Energy Institute (MEI) and the Power and Energy Systems Group, combining academic, industry, and national program engagement to address the technical and operational challenges in a renewable-dominated NEM.

9.2.1.1 Facilities and Capabilities

UoM operates the Smart Grid Lab, a state-of-the-art environment integrating RTDS, SCADA/IEC-61850 interfaces, and control-room infrastructure for relay- and controller-in-the-loop testing. The lab enables high-fidelity investigation of high-DER operations, abnormal conditions, and advanced protection and control schemes, supporting experiments without the risk associated with live-network trials. This capability underpins reproducible studies on DER orchestration, protection adaptation, and voltage and hosting capacity management.

9.2.1.2 Sector Relevance

UoM's research addresses several priority areas for Australian electricity system transformation:

- System Strength and GFM Inverters: Demonstrates how GFM inverters contribute to voltage support and damping under low-SCR conditions.
- DER Integration and Hosting Capacity: Integrated MV–LV modelling informs distribution planning and the design of DOEs.
- Data-Driven DER Behaviour: Analysis of operational data highlights variability in DER response, supporting adaptive coordination strategies.
- Cross-Vector Sector Impacts: Integrated electricity–gas modelling assesses impacts of electrification on system resilience and peak demand.

This work aligns with AR-PST objectives by supporting weak-grid operation, DER integration, and reproducible validation of emerging system behaviours.

9.2.2 Current Research

9.2.2.1 System Strength and Multi-Dimensional Stability Frameworks

Research conducted by Lee, Billimoria, Mancarella and collaborators examines the evolution of system strength, inertia, and stability in power systems dominated by IBRs [56], [57], [58]. Across these studies, conventional metrics such as Short Circuit Ratio (SCR) and Available Fault Level (AFL) are shown to provide limited representation of system behaviour in weak-grid environments, particularly where inverter control dynamics influence network response.

To address these limitations, a multi-dimensional framework is introduced that evaluates:

- voltage stability,
- PLL synchronisation stability, and
- transient stability.

This approach provides a more complete representation of system behaviour by incorporating both network characteristics and inverter control interactions with grid impedance.

The research further indicates that system strength must be interpreted as a dynamic capability influenced by control behaviour, rather than a static network property. This reframing supports improved planning methodologies for identifying weak nodes, assessing hosting capacity, and evaluating mitigation options including grid-forming inverters, SynCons, and demand-side response.

While these expanded system-strength metrics provide a more complete representation of network behaviour, their direct relationship to protection system performance remains less well defined. In particular, there is limited translation of planning metrics such as voltage stability, phase-angle behaviour, oscillatory performance, and inverter control interactions into practical protection performance indicators including directional element reliability, distance-element reach, phase-selection accuracy, fault-location accuracy, and differential protection sensitivity. Bridging this gap between system-strength assessment and protection performance remains an important area for future research.

The framework is primarily applied within planning studies and connection assessments. Its application in real-time operational environments remains limited due to computational complexity and data requirements.

Research Gaps

- Multi-vendor control visibility: Proprietary inverter control models limit the ability to analyse interactions across mixed technology fleets.
- Real-time operationalisation: The framework is not yet suitable for continuous operational use, such as control room stability assessment.
- Locational system strength representation: Aggregate metrics do not adequately capture spatial variability in system strength across the NEM.
- Integration with protection frameworks: Translation of multi-dimensional stability concepts into practical protection coordination methodologies remains limited.

9.2.3 Implications for Australian Practice

Drawing on the consolidated University of Melbourne research pipeline, several critical implications emerge for Australian power system planning, operations, and protection architectures:

- Transitioning from Asset Physics to Multi-Dimensional Strength Frameworks: Traditional Short Circuit Ratio (SCR) planning metrics suffer from an inherently dangerous optimism bias. Adopting a multi-dimensional framework that explicitly incorporates voltage stability, PLL synchronisation, and transient stability allows AEMO and NSPs to accurately evaluate weak-grid boundaries beyond blind, physics-bound short-circuit availability figures [56], [57], [58].

9.2.4 Collaboration Pathways

The University of Melbourne body of work highlights highly structured, actionable pathways to translate advanced control-aware research into immediate operational practice across the NEM:

- **Hardware-in-the-Loop Weak-Grid Protection Trials:** Joint utility studies with NSPs and DNSPs utilizing the University of Melbourne’s Smart Grid Laboratory. Leveraging RTDS alongside IEC 61850 protocol standards allows for comprehensive, closed-loop testing of physical protection relays and multi-vendor inverter controllers under low-fault, current-limited operating conditions [59].

9.3 Monash University

9.3.1 Overview

Monash University conducts research focused on the behaviour of IBRs in weak-grid environments, with particular emphasis on GFM inverter controls, transient stability, and fault response characteristics relevant to protection system performance. This work is undertaken through the Monash Energy Institute, the Grid Innovation Hub, and the Department of Electrical and Computer Systems Engineering, and aligns with emerging operational challenges in the NEM.

A distinguishing characteristic of the Monash research program is the integration of analytical methods with experimental validation. Real-time simulation platforms (RTDS and OPAL-RT), controller-in-the-loop environments (Typhoon HIL), and the Clayton campus microgrid provide a combined capability for investigating inverter behaviour under both simulated and operational conditions. These facilities support detailed assessment of current-limited fault response, control-system dynamics, and multi-inverter interaction in weak-grid networks.

9.3.2 Current Research

9.3.2.1 Grid-Forming Inverter Control and Transient Stability in Weak Grids

The increasing penetration of IBRs introduces new challenges for maintaining transient stability during large disturbances. Unlike synchronous generators, inverter-based resources are constrained by strict semiconductor current limits and rely on control algorithms to maintain synchronism with the grid.

Early work by Ravanji and Bahrani [60] investigated the transient stability behaviour of grid-forming inverters operating under current-limited conditions. The study showed that when current limits are reached during faults, conventional voltage-source control strategies may no longer maintain synchronisation, leading to instability or inverter disconnection.

To characterise this behaviour, a Lyapunov-based framework was developed to define the Region of Attraction (RoA) for inverter equilibrium points. This approach quantifies the combinations of disturbance magnitude and clearing time that can be tolerated without loss of synchronism. The analysis demonstrated that common current-limiting approaches, particularly current reference saturation (CRS), may destabilise the inverter by disrupting phase synchronisation [60].

Alternative strategies were also evaluated, including quadrature-prioritised current limiting and virtual impedance control. These methods improve voltage support and post-fault recovery by prioritising reactive current injection and maintaining synchronising torque under disturbance conditions [60].

Building on this work, Wijayalath and Bahrani [61] developed a modular state-space representation using the Component Connection Method (CCM) to enable consistent comparison of grid-forming control strategies. This framework allows multiple control designs—including droop control, virtual synchronous generator (VSG) control, and compensated VSG variants—to be evaluated under identical conditions.

Comparative analysis using impedance-based and EMT methods indicates that grid-forming control strategies based on power synchronisation provide improved stability performance in weak-grid environments relative to grid-following approaches. These methods demonstrate enhanced voltage-frequency regulation and improved damping of low-frequency oscillations during disturbances [61].

This research is extended within the CSIRO AR-PST program to examine large-signal stability of inverter-dominated systems [62]. The findings indicate that traditional transient stability methods developed for synchronous machines are not directly applicable to inverter-based systems, due to fast control dynamics and strict current limits.

To address this, modified grid-forming control strategies are introduced that anticipate current-limiting behaviour, enabling inverters to remain synchronised even when operating at maximum current. Large-signal stability mapping techniques, based on the RoA framework, are used to define stability boundaries and estimate critical clearing times under varying system conditions [62].

The research also highlights the importance of multi-inverter interaction in weak-grid regions. In areas with high concentrations of inverter-based generation, uncoordinated control parameters may lead to low-frequency oscillatory behaviour between neighbouring inverters, indicating the need for coordinated control tuning [62].

Research Gaps

While these studies establish a detailed understanding of inverter transient stability and control behaviour, several limitations remain in extending these findings to operational and multi-vendor environments.

- Multi-vendor interoperability: Stability analysis relies on detailed inverter models, while commercial devices are typically represented as proprietary “black-box” models, limiting assessment of interaction between different technologies [60], [62]. The aggregate fault response of mixed inverter technologies operating within the same network remains insufficiently understood, particularly where differing control architectures, current-limiting strategies, and fault-response characteristics interact during disturbances.
- Model transparency and representation: The use of black-box models constrains system-level analysis. Further development of grey-box or impedance-based modelling approaches is required to characterise inverter dynamic behaviour without access to proprietary control algorithms [62].

- Inverter-based load interaction: The behaviour of inverter-based loads, including EV charging systems and industrial power electronic loads, is not fully represented within existing transient stability frameworks [60], [62].
  Validation and observability: While stability limits are well-defined in simulation, there is limited capability to validate these behaviours in operational systems. High-resolution measurement and wide-area monitoring are required to confirm these models under real-world conditions [62]. In addition, existing stability studies rarely translate inverter control interactions into practical protection performance outcomes, leaving the impact of control actions on relay operation, fault detection, and protection coordination insufficiently understood.

9.3.2.2 Advanced Inverter Control Under Current-Limited Grid-Forming Operation

The Monash University AR-PST Stage 3 Final Report [63] examines the behaviour of grid-forming inverters (GFMIs) operating under current-limited conditions and the implications for transient stability in renewable-dominated systems. The study identifies current limiting as a fundamental operational constraint, noting that inverter-based resources must maintain stable voltage-source behaviour within strict hardware current limits, unlike synchronous machines.

The results demonstrate that conventional current-limiting strategies can degrade inverter stability during faults. When current limits are reached, voltage control behaviour may deteriorate, leading to loss of synchronisation. To address this, the study evaluates alternative strategies designed to preserve voltage control under disturbance conditions. In particular, quadrature-prioritised current limiting improves transient performance by maintaining reactive current support and voltage stability during faults [63].

The research further investigates virtual impedance control as a mechanism for managing current limits. By dynamically emulating additional impedance during disturbances, this approach constrains current without abrupt clipping, allowing the inverter to maintain stable phase relationships with the grid. Simulation results indicate improved transient stability and enhanced FRT capability in weak-grid environments [63].

A comparative assessment of control architectures—including droop control, VSM implementations, and direct power control—demonstrates that control selection significantly influences dynamic performance. Droop-based approaches support steady-state power sharing but may exhibit oscillatory behaviour in weak grids. VSM approaches improve inertial response but require careful tuning under current-limited conditions, while direct power control provides fast dynamic response with increased control complexity and potential interaction with existing protection systems [63].

The study also identifies the role of grid-forming inverters in influencing system-level behaviour. Properly configured GFM units can provide a stabilising voltage reference for neighbouring grid-following inverters, supporting coordinated operation during disturbances and improving overall system stability [63].

Research Gaps

While this study demonstrates improved control strategies for current-limited grid-forming operation, several limitations remain in translating these results into multi-inverter and operational environments.

- Multi-inverter interaction: Further investigation is required to characterise behaviour where multiple grid-forming inverters from different manufacturers operate within the same network, particularly under differing control strategies [63].
- Translation to performance standards: While advanced control strategies can be demonstrated in simulation, defining simplified performance metrics suitable for generator performance standards (GPS) and regulatory frameworks remains challenging [114].
- Sustained operational performance: The long-duration behaviour of current-limited grid-forming inverters, including thermal limits and operation under multiple simultaneous system services, requires further investigation [63].

9.3.2.3 Stability Enhancement Strategies for Weak-Grid Operation

The Monash Energy Institute [64] evaluates a range of stability-enhancing solutions for weak-grid regions within the NEM, including SynCons, grid-forming inverters, STATCOM devices, and control tuning approaches. The study examines the relative effectiveness of these technologies in improving voltage stability and damping oscillatory behaviour under low system strength conditions.

The analysis indicates that combinations of technologies may provide improved performance relative to individual solutions. In particular, the use of grid-forming inverters in conjunction with limited synchronous support can enhance voltage control capability and improve stability margins in weak-grid environments. This supports a transition from reliance on fault current contribution toward assessment of system strength based on dynamic voltage and control capability.

The study also highlights that stability performance in inverter-dominated systems is strongly influenced by control behaviour and coordination between devices, rather than solely by network strength metrics.

Research Gaps

While the study provides a comparative assessment of stability enhancement approaches, several limitations remain in modelling, protection performance, and multi-inverter coordination.

- Aggregate multi-vendor modelling: The absence of standardised modelling approaches limits the ability to accurately evaluate stability where multiple grid-forming inverter technologies operate within the same network [64].
- Protection system response under current-limited behaviour: Conventional protection schemes may have difficulty distinguishing between fault conditions and inverter current-

limited response, indicating the need for revised protection methodologies suited to low fault-current environments [64].

- Control interaction dynamics: The interaction between different inverter control strategies is not fully characterised, particularly under large disturbances where competing control responses may affect overall system stability [64].

9.3.2.4 Implications for Australian Practice

Drawing on [60] to [65] several implications emerge for the operation and planning of inverter-dominated power systems in the NEM:

- Inverter stability under disturbance conditions is governed by control behaviour and hardware current limits, requiring protection and operational frameworks to account for non-linear, current-constrained responses rather than traditional fault-current assumptions [60] to [63].
- Stability boundaries depend on both disturbance characteristics and local network conditions, including system strength and fault duration, highlighting the need to consider these factors in coordination and planning methodologies [60] to [62].
- Interaction between multiple inverter-based resources introduces additional system dynamics, particularly in high-penetration regions where uncoordinated control behaviour may lead to oscillatory responses [62], [63], [64]
- Declining system inertia alters the temporal characteristics of frequency response, increasing reliance on fast-acting inverter-based services and requiring coordination with protection systems operating under reduced response timeframes [66].
- Improved observability of system dynamics is required, including high-resolution measurement and monitoring infrastructure, to validate the performance of inverter-based stability services and support operational decision-making [62], [63], [66].

9.3.3 Collaboration Pathways

The specialised simulation and living-laboratory infrastructure at Monash University provides several pathways for translating control-aware research into operational protection practice across the NEM. These pathways are characterised by the ability to bridge analytical modelling, laboratory validation, and real-world system operation within a single research environment.

A primary avenue for collaboration is the use of real-time digital simulation platforms, including Real RTDS and Trusted Real-Time Simulation Solutions (OPAL-RT), to support HIL testing with NSPs. This enables physical protection relays and multi-vendor inverter controllers to be embedded directly within simulated weak-grid environments. Such configurations allow detailed investigation of protection system response under current-limited conditions and provide a controlled means of validating settings, coordination strategies, and inverter control behaviour prior to deployment in Renewable Energy Zones (REZs).

In addition, Monash’s work on frequency dynamics and inverter-driven system behaviour provides a technical foundation for engagement with market bodies and regulatory agencies, including AEMO and AEMC. Collaborative efforts in this area may support the ongoing refinement of regional inertia requirements, the assessment of high-speed Rate of RoCoF risks, and the evolution of GPS in inverter-dominated systems.

9.4 The University of Queensland

9.4.1 Overview

The University of Queensland (UQ) approaches inverter-dominated power systems as integrated cyber-physical networks, in which stability, protection, and operational coordination are addressed through a continuous evidentiary chain from theoretical development to field validation. This approach links analytical modelling, identification techniques, hardware-in-the-loop and relay-in-the-loop experimentation, and high-resolution field telemetry to support development of operational guidance.

This methodology is supported by UQ's ownership and operation of utility-scale energy assets, including the Warwick Solar Farm (64 MW), Gatton Solar Farm (3.3 MW PV with 760 kWh storage), and the St Lucia battery energy storage system (1 MW / 2 MWh). These facilities enable the development of digital-twin simulations and real-time inertia estimation methods based on operational data, supporting validation of inverter behaviour under realistic system conditions [118].

A core component of UQ's capability is the Industry 4.0 Energy TestLab, which integrates industry-standard simulation tools, microgrid controllers, commercial protection relays, and SCADA/HMI platforms within a unified testing environment. This facility supports investigation of multi-inverter interoperability, including the interaction of grid-following and grid-forming inverter control strategies with each other and with existing protection systems. The environment provides a platform for evaluating control interactions and protection system performance in weak-grid conditions [67].

UQ also has a strong research focus in synchrophasor and wide-area monitoring systems, providing tools for real-time assessment of frequency and system strength within the NEM. By combining high-speed field telemetry with data-driven techniques, including ML, this work supports:

- **Dynamic stability assessment:** evaluation of system stability limits as operating conditions change.
- **Oscillation detection:** identification of sub-synchronous and low-frequency oscillatory behaviour using wide-area measurement systems.
- **Distributed resource coordination:** development of control and orchestration strategies for aggregating distributed energy resources into system services [68], [69].

9.4.2 Current Research

9.4.2.1 System Strength and Inertia in the National Electricity Market

Gu, Yan, and Saha [70] examine the challenges associated with maintaining system strength and inertia in the NEM as generation transitions from synchronous sources to inverter-based resources. The study identifies declining short-circuit levels and rotational inertia as key factors influencing system stability and notes that conventional metrics may not fully capture system behaviour under high inverter penetration.

The analysis considers potential mitigation approaches, including deployment of SynCons, use of grid-forming inverters to provide stabilising services, and enhancements to generator dispatch formulations to incorporate system strength and inertia constraints.

Research Gaps

While the study provides a baseline assessment of system strength and inertia in the NEM, several limitations remain in translating these findings to evolving operational conditions.

- Real-time inertia and system strength estimation: The study primarily considers offline modelling approaches. Further work is required to develop continuous estimation methods capable of distinguishing between synchronous and inverter-based contributions to system strength and inertia [70].
- **Interaction of mixed inverter technologies:** The behaviour of combined grid-following and grid-forming inverter systems, particularly across multiple vendors, is not fully characterised, including the potential for control interaction under weak-grid conditions [70].
- **Interdependency of stability metrics:** Key indicators such as RoCoF, fault level, and critical clearing time are considered largely independently. Further analysis is required to understand the interaction between these metrics under changing system conditions [70].
- **Market integration of system services:** While regulatory considerations are discussed, mechanisms for incorporating inertia and system strength within dispatch and market frameworks require further development [70].
- **Protection performance in low fault-level networks:** The impact of declining system strength on protection system reliability, including the sensitivity and selectivity of conventional relay schemes, remains an area requiring further investigation [70].

9.4.2.2 System Strength Enhancement with Synchronous Condensers

Upadhayay et al. [71] examine the role of SynCons in supporting system strength in high-renewable power systems. The study considers their contribution to voltage stability and reactive power support under declining fault levels associated with increasing penetration of inverter-based resources.

System strength is represented using metrics such as Short Circuit Ratio (SCR) and Available Fault Current (AFC), which are used to assess network capability for integrating additional renewable generation. The analysis indicates that SynCons provide a stable source of fault current and voltage support, particularly during disturbance conditions, and highlight differences in response relative to power electronic devices.

The study also considers the interaction between SynCons and inverter-based resources, including the role of grid-forming inverters in providing coordinated frequency response. Additional contributions include the incorporation of system strength and inertia constraints into dispatch considerations and the use of screening approaches to identify potential small-signal stability issues in multi-vendor inverter environments [71].

Research Gaps

While the study evaluates the role of SynCons in system strength provision, several limitations remain in modelling, coordination, and operational integration.

- **Real-time estimation of system strength and inertia:** Current approaches rely on offline metrics such as SCR. Further work is required to develop real-time estimation methods capable of capturing rapid variations associated with inverter-based resources [71].
- **Interaction between** SynCons **and inverter-based resources:** The combined behaviour of electromechanical devices and inverter control systems is not fully characterised, particularly under weak-grid conditions where dynamic interaction may affect stability [71].
- **Non-linear behaviour in weak grids:** Existing modelling approaches are often based on linearised representations and may not accurately capture behaviour under very low system strength conditions [71].
- **Valuation and market integration:** Mechanisms for valuing system strength services, including contributions from SynCons, remain underdeveloped within current market frameworks [71].
- **Spatial variation in system behaviour:** Conventional models assume uniform system response and do not fully represent spatial variations in strength and frequency behaviour across large networks [71].

9.4.2.3 Implications for Australian Practice

Drawing on [70] to [72] several practical implications emerge for the Australian electricity system:

- Protection and Observability: Black-box IBRs necessitate measurement-constrained validation. Protection schemes must be reviewed for inverter fault characteristics, and real-time monitoring via operational telemetry or PMUs is crucial [67], [72].

Collectively, these insights provide a blueprint for AR-PST-aligned studies and for shaping NEM planning, operations, and regulatory frameworks.

9.4.2.4 Collaboration Pathways

The University of Queensland (UQ) research program highlights several pathways for translating inverter-focused and operational research into practice within the NEM:

- GFM and GFL stability and protection testing: Joint hardware-in-the-loop and relay-in-the-loop studies with CSIRO and NSPs provide a platform for evaluating grid-forming inverter tuning, fault current behaviour, and mode-switching dynamics under weak-grid conditions [73], [72].
- DER management and DOE trials: Collaboration with DNSPs supports deployment of DOE frameworks across representative low-voltage feeders, including coordination of distributed PV and battery systems and assessment of protection interactions [68].

These pathways support the transition of UQ's research from laboratory and simulation environments into operational practices for system operators and network planners.

9.4.2.5 System Strength, Inertia, and Protection in IBR-Dominated Systems

A central theme of UQ research is the evolving nature of system strength and inertia in inverter-dominated grids, and their implications for system stability and protection performance. Gu, Yan, and Saha [70] examine the decline in short-circuit levels and rotational inertia in the NEM, highlighting limitations of traditional metrics in characterising stability under high IBR penetration. The work identifies risks associated with weak-grid conditions, including reduced fault levels and altered dynamic response during disturbances.

Related studies extend this analysis to frequency control mechanisms and system-wide stability management. Maurer, Wilson, and Chapman [73], together with Alam et al. [67], examine the role of grid-forming inverters, battery energy storage systems (BESS), and distributed energy resources in providing FFR and synthetic inertia. These works emphasise the increasing dependence on inverter-based control systems to manage frequency excursions, particularly under low-inertia conditions where conventional synchronous support is limited.

Across these studies, a consistent observation is that reduced system strength and inertia influence both the magnitude and temporal characteristics of disturbance signals. This has implications for protection systems that rely on stable fault current profiles and predictable frequency response, particularly in weak-grid environments where inverter control behaviour can dominate system dynamics.

9.4.2.6 Inverter Interaction, Control Stability, and Protection Observability

UQ research also examines the interaction between multiple inverter-based resources and the resulting impact on system stability and disturbance observability. Studies highlight the potential for complex control-loop interactions between grid-following and grid-forming inverters, particularly where devices from different manufacturers operate within the same network region [70], [73].

These interactions are associated with oscillatory behaviour, sensitivity to network impedance, and variability in response during fault conditions. Inverter current-limiting behaviour further alters traditional fault signatures, reducing available fault current and affecting the performance of legacy protection schemes. This has led to increased focus on the compatibility between inverter control strategies and protection system operation, particularly under low short-circuit conditions.

Complementing this work, research in wide-area monitoring and synchrophasor systems enables improved detection and interpretation of these behaviours. By applying high-speed measurement and data analytics, UQ studies demonstrate the capability to identify oscillations, track dynamic stability limits, and improve visibility of system response during disturbances [68], [69]. These approaches provide an alternative means of interpreting system conditions where conventional protection signals may be reduced or ambiguous.

Inverter current-limiting behaviour further alters traditional fault signatures, reducing available fault current and affecting the performance of legacy protection schemes [67].

9.4.2.7 Hybrid System Strength Solutions and DER Coordination

Further work investigates approaches for maintaining system strength and stability through coordinated deployment of physical and inverter-based resources. Upadhayay et al. [71] examine the application of SynCons to provide fault current and voltage support in weak-grid environments, demonstrating their effectiveness during severe disturbances.

Building on this concept, Li, Gu, and colleagues [72] propose the integration of inverter-based resources with SynCons to form GSI units. These hybrid configurations combine the high fault current capability of synchronous machines with the controllability of inverter-based resources, supporting both protection system requirements and frequency control performance.

At the distribution level, Stringer et al. [68] examine the coordination of distributed energy resources through DOEs. This work addresses challenges associated with high penetrations of rooftop photovoltaic systems, including voltage rise and the risk of coordinated inverter disconnection during disturbances. The implementation of adaptive export limits is shown to support network stability while maintaining DER participation.

Collectively, these studies highlight the increasing integration of control-based and physical mechanisms for maintaining system stability, with direct implications for protection system performance across both transmission and distribution networks.

9.4.3 Research Gaps

Despite the breadth of research conducted, several key gaps remain in translating these insights into protection system design and operational practice.

A primary limitation relates to the real-time observability of system strength and inertia. While existing studies provide comprehensive modelling frameworks, discrepancies between calculated and measured system behaviour persist, particularly where demand-side contributions and distributed energy resources are involved. This limits the ability to accurately assess protection margins and disturbance response under changing system conditions [70], [67].

In addition, the interaction of multiple inverter technologies under disturbance conditions remains incompletely characterised. Variability in control strategies—particularly across grid-following and grid-forming implementations, and across different manufacturers—introduces uncertainty in system response during faults. This includes the potential for oscillatory instability, control interaction, and altered fault signatures that are not readily captured in conventional protection studies [70], [73].

A further gap concerns the representation of inverter-driven behaviour within protection design frameworks. Existing protection methodologies are largely based on steady-state or phasor-domain assumptions, with limited capability to incorporate non-linear control dynamics, current-limited behaviour, and fast transient response. This creates challenges in maintaining sensitivity and selectivity in weak-grid environments.

There is also a need to better understand the spatial and temporal variability of system response, particularly in networks with distributed synthetic inertia and high DER penetration. Localised frequency deviations, non-uniform system strength, and varying disturbance propagation characteristics introduce complexity in coordinating wide-area protection schemes [67], [71].

Finally, limitations remain in the validation of system performance under realistic operating conditions. While simulation and laboratory-based testing are well established, further work is required to integrate high-fidelity telemetry, digital twin frameworks, and hardware-in-the-loop environments to validate system behaviour and protection performance across a wider range of operating scenarios.

9.4.4 Implications for Protection Practice

The UQ research highlights several considerations relevant to protection system performance in the NEM under high penetrations of inverter-based resources:

- The reduction in system strength and fault current levels affects the sensitivity and selectivity of protection schemes designed for synchronous-dominated networks. In addition, inverter current-limiting behaviour and control-based response introduce variability in fault characteristics, complicating the interpretation of disturbance signals.
- The increasing reliance on inverter-based frequency control and synthetic inertia also changes the temporal profile of system response during disturbances, with faster dynamics and reduced inertial buffering. This influences the coordination of wide-area protection schemes, including those dependent on frequency and RoCoF measurements.
- The use of high-speed monitoring systems, such as PMUs and wide-area measurement frameworks, provides improved visibility of system behaviour and supports the identification of dynamic phenomena that may not be captured by conventional protection signals. These capabilities are particularly relevant in weak-grid environments and networks with high DER penetration.

- Finally, the coordination of distributed energy resources through mechanisms such as DOEs introduces an additional layer of control interaction, which may influence system response during disturbances and requires consideration in protection system assessment.

9.4.5 Collaboration Pathways

UQ's integrated research infrastructure provides several opportunities for collaboration with industry and market bodies to support the application of these findings in operational settings.

The industry 4.0 Energy TestLab and associated real-time simulation platforms enable hardware-in-the-loop testing of protection relays and inverter controllers in weak-grid environments. This supports collaborative validation of protection performance, inverter control strategies, and system behaviour under current-limited conditions [67], [73].

In parallel, the availability of utility-scale assets and high-resolution telemetry enables field-based validation of system strength, inertia estimation, and frequency response performance. Collaborative projects with NSPs can leverage these capabilities to assess protection system behaviour under realistic operating conditions [70], [67].

Opportunities also exist for joint development of wide-area monitoring and data analytics frameworks. By integrating synchrophasor data and advanced analysis methods, these collaborations can improve visibility of inverter-driven dynamics and support enhanced disturbance detection and interpretation [68], [69].

Finally, UQ's work on system strength and frequency control provides a basis for engagement with AEMO and regulatory bodies in the development of performance standards and operational frameworks. This includes contributions to methodologies for assessing system strength, inertia requirements, and inverter-based services within the NEM.

9.5 The University of Tasmania

9.5.1 Overview

The University of Tasmania (UTAS) contributes to research addressing protection and stability challenges associated with high-renewable power systems through its Centre for Renewable Energy and Power Systems (CREPS). UTAS maintains close research collaboration with Tasmanian energy institutions, including Hydro Tasmania and TasNetworks, enabling the investigation of power-system stability issues in a network characterised by high renewable penetration, strong hydro-inertia, and significant interconnection with the mainland NEM.

Within the Australian Renewable Energy Agency's Advanced Research Program AR-PST, UTAS is formally the lead research institution for Topic 5 (System Restoration). Nevertheless, its research portfolio also contributes substantially to Topic 6: System Services, particularly through studies examining FFR, Battery Energy Storage Systems (BESS), and the stability characteristics of IBRs [74], [75], [76], [77].

A significant portion of UTAS research investigates the provision of frequency-control services in low-inertia systems. This includes evaluating how battery energy storage can deliver rapid active-power injection following system disturbances, reducing the RoCoF and improving frequency-recovery performance compared with conventional synchronous-generator responses [74], [78].

UTAS researchers have also examined the capability of Grid-Forming Inverters (GFMIs) to emulate synchronous characteristics and provide essential system services (ESS) such as synthetic inertia, voltage support, and oscillation damping in inverter-dominated power systems. These investigations include the development of state-of-charge aware frequency-control strategies for inverter-based storage systems and the assessment of their contribution to grid stability [76], [77].

Further work has focused on defining system-level metrics for assessing frequency performance in modern power systems. This includes research on Frequency Control Strength, which provides a framework for quantifying the capability of a power system to maintain frequency stability under low-inertia conditions [79].

The Tasmanian power system provides a unique operational environment for these investigations. Its combination of hydro-dominated synchronous generation, emerging inverter-based resources, and major interconnection infrastructure enables UTAS researchers to examine the evolving interaction between synchronous inertia and synthetic inertia as renewable penetration increases. This hybrid system environment provides a practical testbed for evaluating system-service requirements under future high-renewable scenarios [80], [77].

9.5.2 Current Research

9.5.2.1 Fast Extraction of Non-Stationary Signal Components Using Dynamic Adaline

Eslami, Negnevitsky, and Franklin [81] investigate signal-processing methods for analysing rapidly changing electrical signals in inverter-dominated power systems. The research introduces a Dynamic Adaline (Adaptive Linear Neuron) framework capable of extracting fundamental and distorted signal components under non-stationary conditions, where both frequency and amplitude vary over short time intervals.

Conventional techniques such as Fast Fourier Transform (FFT) methods rely on quasi-stationary assumptions and may exhibit reduced accuracy when applied to rapidly varying signals. The proposed approach treats frequency as a time-varying parameter, enabling simultaneous estimation of instantaneous frequency and harmonic content without prior identification of signal components.

Simulation results indicate that the method can achieve accurate signal estimation using partial-cycle data, improving response speed compared with conventional full-cycle approaches. The method also maintains performance under conditions with interharmonics and low signal-to-noise ratios, which are characteristic of inverter-dominated networks [81].

Research Gaps

While the method demonstrates capability for analysing non-stationary signals, several limitations remain in implementation and system integration.

- Hardware implementation and validation: Further work is required to assess performance in real-time control hardware and hardware-in-the-loop environments with computational constraints [81].
- Scalability to multiple signals: The approach is demonstrated for individual signals and requires evaluation for aggregated measurements across distributed energy resources [81].
- Integration with control and protection systems: Application within real-time protection and control environments, including FFR and inverter control strategies, requires further development [81].

9.5.2.2 Collaboration Pathways

The University of Tasmania (UTAS) research program provides several pathways for collaboration with Australian power system stakeholders, including CSIRO, the Australian Energy Market Operator (AEMO), and NSPs.

- Advanced measurement and monitoring techniques: Signal-processing methods for analysing non-stationary electrical signals support potential collaboration on real-time monitoring, power quality assessment, and oscillation detection in inverter-dominated networks [81].

9.6 Charles Darwin University

9.6.1 Overview

Charles Darwin University (CDU) conducts research addressing key challenges associated with inverter-dominated power systems, particularly under weak-grid conditions characterised by low fault levels, reduced system strength, and fast inverter-driven dynamics. These conditions are already prevalent in the Northern Territory, providing a practical environment for investigating system behaviour relevant to the ongoing transition of the NEM [82], [83].

A central component of CDU's capability is the Remote Energy Microgrid Hardware and Real-Time (REMHART) platform, which provides an experimental environment for studying power system stability using HIL simulation. By integrating physical inverter and battery systems with real-time disturbance scenarios, REMHART supports evaluation of protection performance and control behaviour in low short-circuit ratio (SCR) networks [79, 80].

These capabilities support investigation of grid-forming inverter control, protection coordination, and system stability in weak-grid environments. The insights obtained are relevant to the development of operational and planning approaches for inverter-based resources, particularly in REZ contexts [84], [85].

9.6.2 Current Research

9.6.2.1 Stability of Microgrids under Dynamic Load and Renewable Variability

Hossain and Thennadil [84] investigate stability characteristics of islanded microgrids under conditions of high inverter-based resource penetration and dynamic load variation. The study examines both transient and small-signal stability behaviour in systems subject to rapid changes in solar generation and industrial load demand.

The analysis identifies the impact of non-stationary operating conditions, where simultaneous fluctuations in generation and load introduce dynamics that are not well captured by conventional control approaches. Under these conditions, stability limits become sensitive to system strength, with low short-circuit ratio (SCR) resulting in reduced robustness of conventional droop-controlled inverters.

To address these challenges, the study proposes an adaptive damping approach in which grid-forming inverter control parameters are adjusted based on real-time system conditions. This enables improved damping of oscillatory behaviour and supports stable operation under high renewable penetration.

Experimental validation using the REMHART platform demonstrates that adaptive control strategies can improve stability performance in weak-grid microgrid environments, particularly under conditions of rapid variability and high inverter penetration [84].

Research Gaps

While the study advances understanding of stability in weak-grid microgrids, several limitations remain in scaling and system integration.

- Interoperability of adaptive control strategies: The behaviour of multiple inverters using different control implementations is not fully characterised [84].
- Interaction with protection systems: The impact of adaptive inverter response on conventional protection schemes, including potential misidentification of disturbances, requires further investigation [84].
- Scalability to larger networks: Application of microgrid-based control strategies to utility-scale networks, including REZs, remains to be assessed [84].

9.6.2.2 Adaptive Control Strategies for Grid-Forming Inverters in Weak-Grid Environments

Thennadil and Hossain [85] investigate adaptive control strategies for grid-forming inverters operating in weak-grid environments characterised by low short-circuit ratio (SCR) and limited synchronous generation. The study examines stability challenges arising from increased sensitivity to disturbances in such systems.

The proposed approach employs adaptive virtual impedance control, in which inverter parameters are adjusted in real time based on estimated grid impedance. This enables the inverter to maintain stable operation across a range of system conditions, including low-SCR environments where conventional fixed-parameter control strategies may be insufficient.

The analysis includes small-signal stability assessment, indicating that adaptive control can improve voltage regulation and maintain stable operation under weak-grid conditions. The approach also demonstrates robustness to uncertainty in network parameters, which is relevant in systems with limited or imprecise network modelling.

The study further considers the contribution of adaptive grid-forming control to system strength by stabilising voltage behaviour and damping oscillations, thereby supporting the integration of additional inverter-based resources [85].

Research Gaps

While the study examines adaptive control for grid-forming inverters, several limitations remain in extending these approaches to system-wide deployment.

- Interaction with fault current limitations: The compatibility of adaptive control strategies with inverter current limits during fault conditions requires further investigation [85].
- Coordination of multiple adaptive inverters: The behaviour of multiple grid-forming inverters using adaptive control across larger networks is not fully characterised [85].
- Protection system interaction: Dynamic changes in inverter impedance may affect operation of impedance-based protection schemes, including distance protection [85].

9.6.2.3 Hardware-in-the-Loop Validation of Protection Schemes in Inverter-Dominated Microgrids

Lu, Hossain, and Thennadil [86] investigate the performance of protection systems in inverter-dominated microgrids using HIL validation techniques. The study utilises the REMHART platform to replicate weak-grid conditions representative of remote power systems with low inertia and limited fault current.

By integrating physical protection relays with real-time digital simulation, the research evaluates how conventional protection schemes respond under inverter-dominated fault conditions. The analysis highlights that inverter-based resources, which operate with limited overcurrent capability, provide significantly lower fault current compared with synchronous generators.

The results indicate that traditional overcurrent protection schemes, including inverse definite minimum time (IDMT) relays, may not reliably detect faults under low short-circuit ratio conditions. This can lead to reduced sensitivity of protection systems in high-renewable networks.

To address this limitation, the study examines adaptive protection approaches in which inverter control systems modify their response during fault events to enable improved detection by conventional relays. This approach allows coordination between inverter behaviour and protection systems without exceeding device current limits [86].

Research Gaps

While the study evaluates protection performance in weak-grid microgrids, several limitations remain in extending these approaches to broader system application.

- Multi-vendor protection interoperability: Behaviour across different relay types and manufacturers under adaptive protection schemes is not fully characterised [86].
- Communication latency and reliability: The performance of coordinated inverter–protection interaction under realistic communication constraints, including delay and data loss, requires further investigation [86].
- Interaction with transmission-level protection: The impact of inverter-limited fault currents on upstream protection schemes, including distance protection, is not fully understood [86].

9.6.3 Collaboration Pathways

The Charles Darwin University (CDU) research program provides several pathways for collaboration with Australian power system stakeholders, including CSIRO, the Australian Energy Market Operator (AEMO), and NSPs. These pathways reflect CDU's focus on weak-grid behaviour, inverter-based control, and protection performance in low-inertia systems.

1. System-level modelling and simulation:

Advanced control approaches developed at CDU, including adaptive damping strategies, distributed control architectures, and data-driven frequency control methods, provide a basis for enhancing system-level simulation of inverter-dominated networks. Integration of these approaches into broader modelling studies can support improved representation of fast dynamic behaviour and weak-grid conditions [82], [84], [87].

2. Operational standards and service definition:

Research into grid-forming inverter control and fault-response behaviour supports development of technical requirements for emerging system services. These capabilities may inform evaluation of frequency response performance, system strength contributions, and inverter-based service provision in low-inertia environments [86], [85].

3. Network planning and protection integration:

Hardware-in-the-loop validation of protection systems provides a practical basis for collaboration with NSPs on protection coordination in low short-circuit ratio networks. These capabilities support assessment of protection performance, relay settings, and inverter–protection interaction in both microgrid and REZ contexts [86], [84].

These pathways support the translation of CDU research into operational practices and planning frameworks relevant to inverter-dominated power systems.

The experimental and theoretical research conducted at Charles Darwin University, particularly within the unique environment of the REMHART facility, provides a robust foundation for national collaboration. Leveraging the Northern Territory's "lead indicator" status, these efforts translate into scalable solutions that address the technical, operational, and regulatory transformation of the Australian power system, while specifically supporting AR-PST Topic 6 challenges. These pathways are structured across three primary domains:

1. **Network Planning and Protection Integration (NSPs):** For NSPs, CDU's HIL validation of protection schemes provides a practical toolkit for managing REZs and high-DER distribution feeders. NSPs can draw upon CDU's findings to evaluate new protection coordination strategies that remain sensitive in low-short-circuit-ratio (SCR) environments, ensuring that the integration of GFM inverters supports, rather than compromises, existing grid safety infrastructure [84], [86].

9.6.4 Future Work

The body of research produced by Charles Darwin University identifies several critical frontiers required to ensure the reliable operation of Australia's future inverter-dominated power system. Future investigations are prioritised across four strategic pillars:

1. **Scalability to REZs:** A primary focus of future research involves extending the adaptive damping [84] and distributed control architectures [87] from isolated microgrids to larger, transmission-level weak-grid environments. Validating these strategies on mainland-scale network models is essential to determine the scalability of adaptive GFM control [85] and its ability to maintain stability across expansive REZs.
2. **Multi-Inverter Interoperability and Coordination:** As heterogeneous inverter fleets expand, additional work is required to validate interoperability under mixed-manufacturer deployments. This includes the development of multi-inverter coordination strategies and the testing of model-free adaptive controllers [82] within Hardware-in-the-Loop (HIL) platforms like REMHART to prevent adverse control interactions and sub-synchronous oscillations.
3. **Hardware-Validated Protection and Security:** Future research must deepen the integration of adaptive controllers into dynamic protection studies [84], [86]. This involves testing adaptive protection approaches under a wider range of fault scenarios to ensure compatibility with existing relay technologies. Furthermore, as control becomes more distributed, investigating cybersecurity protections for consensus protocols and ensuring the resilience of AI-driven frequency services against data-injection attacks is a high-priority gap [87], [82].

10. Task 6 – Innovative Global Projects

This section reviews international research and field deployments addressing protection system performance in power networks with high penetration of inverter-based resources. Information is drawn from CIGRE technical guidance, NREL research programs and stakeholder engagement, and published case studies from utilities that have deployed innovative protection solutions in weak grid environments. Relevant IEEE standards including IEEE 2800 and IEEE 2030 are referenced within the technical discussions.

The purpose of this review is to understand global developments and future directions in protection systems, identify insights, methodologies, and emerging practices directly applicable to the Australian power system context, and support evidence-based guidelines for utilities, regulators, and industry stakeholders.

10.1 CIGRE

Study Committee B5 (Protection and Automation) has made protection challenges in IBR rich and low fault current networks a sustained priority, producing technical brochures, conference preferential subjects, and active working groups that collectively represent international consensus on the state of knowledge and recommended approaches. The subsections below outline some of the developments to date.

10.1.1 Technical Brochure 896: Protection for Developing Networks with Limited Fault Current

Working Group B5.48 published Technical Brochure 896 in April 2023, titled "Protection for Developing Network with Limited Fault Current Capability of Generation [3]". The brochure represents one of the most comprehensive international treatment of protection challenges arising from IBR penetration and provides benchmark test systems for protection research to date.

The working group established that traditional protection was designed based on fault characteristics of conventional systems with thermal generation as the primary energy source. New generation types, network structures, and loads integrated into the grid create challenges for protection functions that were not anticipated in original protection philosophies.

Key findings documented in TB 896 include:

- Fault current magnitude: IBRs provide fault currents limited to 1.2 to 1.5 per unit of which is much smaller than the short-circuit current of synchronous generators. This reduction directly affects overcurrent element sensitivity and may prevent operation within required timeframes.
- Sequence component behaviour: IBRs produce negative sequence current only if their control systems are programmed to do so, and many control schemes actively suppress negative sequence to prevent unbalanced loading of power electronics. Even when negative sequence injection is implemented, an inevitable delay of several tens of milliseconds is required for converter control adjustment under transient conditions, longer than the expected reaction time of most instantaneous protections.
- Differential protection limitations: When a fault occurs on a line with IBR at both terminals, fault currents from both ends may be similarly limited, approaching the differential element pickup threshold. In extreme weak grid conditions, restraint current can exceed differential current, causing failure to operate.
- Harmonic injection: IBRs inject harmonics potentially up to high harmonic ranges, which can cause phasor calculation errors affecting impedance measurement and differential comparison within the protection zone.

10.1.2 Protection Schemes Independent of Source Characteristics

CIGRE analysis identifies the most pragmatic approach as modifying protection functions to make them independent of source characteristics rather than attempting to adapt IBR behaviour to suit existing protection [3]. Two protection technologies are identified as fundamentally unaffected by IBR fault current limitations:

- TW protection: Because detection is based on high frequency transients generated at fault inception rather than fundamental frequency phasors, TW protection operates independently of fault current magnitude[11]. CIGRE confirms this technology is uniquely suited for transmission line protection in systems with up to 100% IBR penetration. Working Group B5.55 specifically addresses application of TW technology for protection and automation.
- Differential protection: With limitations, differential protection remains one of the most dependable schemes in IBR environments because it measures current balance rather than absolute magnitude. Modern differential relays incorporate enhanced sensitivity, adaptive restraint[12], and filtering to address low and rapidly decaying fault current. Some incorporate IBR specific features that adjust thresholds based on fault duration or harmonic content. However, TB 896 documents that differential protection can still fail when fault currents from both terminals approach zero in fully IBR dominated systems.

10.1.3 CIGRE Main Findings

Technical Brochure 896 establishes that traditional protection philosophies were developed assuming fault characteristics of conventional systems with thermal generation as the primary energy source. The integration of new generation types, network structures, and loads creates challenges that were not anticipated in original protection design. Rather than attempting to adapt IBR behaviour to suit existing protection schemes, CIGRE analysis identifies the most pragmatic approach as modifying protection functions to make them independent of source characteristics.

Two protection technologies are identified as fundamentally suited for high IBR penetration systems:

TW protection operates independently of fault current magnitude because detection is based on high frequency transients generated at fault inception rather than fundamental frequency phasors. CIGRE confirms this technology is uniquely suited for transmission line protection in systems with up to 100% IBR penetration.

Differential protection remains one of the most dependable schemes in IBR environments because it measures current balance rather than absolute magnitude. Modern differential relays incorporate

[11] While travelling-wave protection is largely independent of fault current magnitude, the characteristics of the high-frequency transients used by travelling-wave algorithms may be influenced by inverter control strategies under certain operating conditions. Refer Section 8.3 for further discussion.

[12] Modern differential relays may employ adaptive restraint, filtering, harmonic supervision, waveform-based processing, and time-domain techniques to accommodate changing fault-current characteristics. Detailed implementation methods are typically proprietary. Refer Section 8.5 Differential Protection for further discussion.

enhanced sensitivity, adaptive restraint, and filtering to address low and rapidly decaying fault current. Some incorporate IBR specific features that adjust thresholds based on fault duration or harmonic content. However, TB 896 documents that differential protection can still fail when fault currents from both terminals approach zero in fully IBR dominated systems.

10.2 NREL Research on Protection in Weak Grids

The National Renewable Energy Laboratory (NREL) leads significant research programs addressing protection challenges in power systems with high IBR penetration. This section draws on published NREL research, including the UNIFI Consortium specifications, studies on IBR effects on protection relay elements, and TW based protection research, as well as a stakeholder interview conducted with the NREL team in December 2025 [88] [89] [90] [91].

10.2.1 IBR Effects on Protection Relay Elements

Wang and Johnson (2025) provide a comprehensive study of how IBR modelling and controls affect transmission line protection [89]. The research identifies that IBRs exhibit fault responses that differ significantly from those of synchronous generators, which can challenge the reliable operation of many commonly used power system protection elements. The fault response of IBRs is primarily influenced by their control algorithms and configurations [89].

The study reveals that certain aspects do not significantly affect relay response, including the type of DC source (battery, PV, or hybrid), inverter model (average versus switching), and power level control methods. However, faster control loops such as current control and current limiting do influence relay behaviour. The study also explores the effects of momentary cessation, operating points, fast and slow current responses, and grid strength on relay performance [89].

IEEE 2800 2022 requires that for unbalanced faults, IBRs must inject negative sequence current, with response times for IBR units (excluding Type III wind turbine generators) of less than or equal to 4 cycles. Protection engineers should desensitise negative sequence dependent elements if the IBR does not support IEEE 2800 compliant negative sequence current control. IBRs need to remain connected for at least 2 cycles to allow proper relay tripping for severe faults where voltage is less than 10% of nominal [89].

10.2.2 Oversizing Inverter Requirements for Fault Current

During the interview NREL indicated that there is currently no coordinated standard for inverter sizing relative to load for protection purposes. Different utilities have different preferences, with the ratio of grid-forming inverter capacity to load varying significantly across the industry. Reported requirements range from 1.5 times to 3.5 times the load, with utilities selecting values based on their comfort level and operational experience [91].

This inverter sizing ratio directly affects both black start capability and fault current contribution. Regardless of the control mode (grid-forming or grid-following), inverters cannot provide fault current beyond their power rating. If the inverter is not appropriately sized, it cannot deliver sufficient current during fault conditions or during transients.

The sizing requirement therefore feeds directly into protection coordination, as it determines the available fault current for relay operation [91].

IEEE 2030 provides a standard for microgrid protection that addresses protection requirements when IBR assets are present and when the microgrid is grid connected versus islanded. This standard covers both grid-forming and grid-following inverters, though Prabakar noted that the mode of operation is less significant than the apparent power rating for protection purposes [91].

10.2.3 Emerging Protection Technologies

TW Based Protection: NREL has published research on TW-based protection as an alternative to phasor domain approaches [3]. TW analysis is suitable for systems with high IBR penetration because it does not depend on large fault currents or phasor information used by traditional protection schemes. TW-based protection has been successfully deployed at transmission level in the US, with products readily available and significant field deployment. However, distribution level TW products are not yet widely available due to the challenges posed by signal reflections at lower voltage levels [90], [91].

Artificial Intelligence Based Protection: Prabakar identified AI and ML based protection as a significant emerging technology. Research indicates detection accuracy exceeding 99.9% in statistical studies, which compares favourably with traditional microprocessor-based protection systems. NREL and other laboratories are developing AI models using time domain current and voltage signals, with training conducted on extensive datasets. While no field deployed AI based protection systems exist at present, Prabakar indicated that field deployment is anticipated within two to three years. Major relay manufacturers including ABB, Eaton, Siemens, and SEL are understood to be developing AI based protection technologies [91].

EMT Modelling for Protection Studies: NREL uses EMT simulation rather than positive sequence models for protection studies involving IBRs. This approach enables accurate modelling of inverter fault current contribution and point on wave analysis. EMT simulation allows both the inverter and relay actions to be modelled, providing better representation of actual system behaviour than positive sequence tools [91].

10.2.4 Grid-forming Inverter Deployment Experience

Prabakar reported that grid-forming capability is becoming a standard requirement for battery energy storage systems in the US. Most battery assets are now required to have grid-forming capability, resulting in significant deployment of grid-forming inverters at distribution level [91].

However, grid-forming mode is typically operated only in islanded conditions, with inverters reverting to grid-following mode when grid connected. This approach addresses anti-islanding concerns while still providing voltage and frequency support during island operation. The challenge of operating grid-forming inverters while grid connected at distribution level remains an active area of development [91].

10.2.5 Industry Practice and Challenges

Prabakar noted several challenges in current industry practice. Protection engineers at utilities frequently face uncertainty regarding relay operation, with concerns about protection scheme efficacy being common. When protection issues occur, utilities often apply targeted solutions rather than comprehensive remediation, with limited documentation and sharing of lessons learned across the industry. This has resulted in protection practice becoming partially dependent on institutional knowledge and experience [91].

HIL testing is a standard practice in the US for protection performance validation. NREL maintains laboratory facilities with actual inverters and power devices to which faults can be applied, enabling characterisation of fault behaviour for model development and validation [91].

The emergence of data centre loads with backup generation (diesel generators and inverters) may organically affect grid strength. If data centre owners are motivated to operate their backup systems in droop mode continuously, this could provide additional fault current contribution and improve system strength in areas with significant data centre development [91].

10.2.6 Relevance to Australian Practice

The NREL research and stakeholder insights provide several findings directly applicable to Australian protection practice:

- The variability in US utility requirements for inverter sizing (1.5 to 3.5 times the load capacity) suggests Australian standards may benefit from specifying minimum fault current requirements for IBR dominated networks.
- AI and ML based protection represents a near term development that Australian utilities should monitor, with field deployment anticipated within two to three years.
- TW protection at transmission level is proven technology that may address some weak grid protection challenges in the NEM.
- EMT simulation should be the standard approach for protection studies involving IBRs, rather than positive sequence tools.

10.3 International Utilities Applications

10.3.1 NamPower (Namibia)

NamPower, the national utility of Namibia in southern Africa, deployed SEL T400L TW relays on the 220 kV Khan to Omburu transmission line (113.6 km) near Omaruru. On 4 February 2020, a phase to ground fault provided direct comparison between TW and conventional protection on the same circuit. The TW differential element cleared the fault in 1.09 ms while the line current differential required 13.87 ms [92] . This order of magnitude speed improvement reduces fault energy, limits equipment stress, and minimises voltage depression duration. NamPower reported no misoperations since deployment.

10.3.2 Public Service Company of New Mexico (United States)

PNM, serving approximately 530,000 customers in the southwestern United States, deployed SEL T400L relays on a 345 kV series compensated line where conventional distance protection faced coordination difficulties due to capacitor voltage inversion effects. Testing at the RTDS Technologies facility in Canada achieved fault location accuracy of 32 m on a 53.3 km line. PNM became the first utility worldwide to enable direct tripping rather than monitoring mode, demonstrating confidence in the technology for primary protection [93].

10.3.3 Commonwealth Edison (United States)

ComEd, serving northern Illinois including Chicago, confirmed single ended TW fault location accuracy of 200 m on a 91.1 km 345 kV line. Following a fault caused by bird contamination, crews were dispatched directly to the faulted span without line patrol, reducing restoration time from hours to minutes [92]. This operational efficiency benefit applies regardless of system strength.

10.3.4 UK Stability Pathfinder

National Grid ESO, the electricity system operator (ESO) for Great Britain, conducted the Stability Pathfinder Phase 2 procurement in 2022, awarding GBP 323 million for 11.55 GVA of short circuit level in Scotland split between five grid-forming batteries and five SynCons [94]. Analysis by SMA (Germany) through the Energy Systems Integration Group found grid-forming batteries provided 65% of contracted inertia but only 21% of contracted short circuit level, while SynCons provided 35% of inertia but 79% of short circuit level [95]. This quantifies the protection limitation: grid-forming inverters excel at inertial response but provide substantially less fault current.

10.3.5 Deployment Status

TW protection is commercially available and deployed for transmission applications. For utilities. Extension to distribution remains under development due to algorithm requirements for shorter lines.

10.4 Summary and Conclusions

The review of international research and field deployments reveals a consistent finding across all sources: traditional protection philosophies developed for synchronous generator dominated systems require fundamental adaptation for networks with high IBR penetration. CIGRE Technical Brochure 896 [3], NREL research programs, and utility deployment experience converge on several key conclusions.

Protection schemes that operate independently of fault current magnitude offer the most robust path forward. TW protection has progressed from research concept to proven field deployment, with utilities in Namibia, the United States, and elsewhere demonstrating reliable operation and significant performance improvements over conventional distance and overcurrent schemes. CIGRE confirms TW technology is uniquely suited for transmission line protection in systems and distribution level applications remain under development.

Differential protection retains value in IBR environments due to its dependence on current balance rather than absolute magnitude, though CIGRE documents potential failure modes when for lower currents in fully IBR dominated systems. Modern differential relays with enhanced sensitivity and adaptive restraint partially address these limitations.

Artificial intelligence and ML based protection represents an emerging technology with detection accuracy exceeding 99.9% in laboratory studies. NREL anticipates field deployment within two to three years, with major relay manufacturers actively developing products. This technology warrants monitoring by Australian utilities as a potential near term solution for weak grid protection challenges.

The absence of coordinated standards for inverter sizing relative to protection requirements presents a gap in current practice. US utility requirements vary from 1.5 to 3.5 times load capacity, reflecting the lack of consensus on minimum fault current contribution for protection coordination. Australian standards development may benefit from establishing explicit requirements to ensure consistent protection performance across IBR dominated networks.

Grid-forming inverter deployment experience in the US indicates that while grid-forming capability is becoming standard for battery energy storage systems, grid-forming mode is typically operated only in islanded conditions. The UK Stability Pathfinder procurement quantifies the protection limitation: grid-forming batteries provided only 21% of contracted short circuit level compared to 79% from SynCons, despite providing 65% of contracted inertia. This confirms that grid-forming inverters, while valuable for stability services, do not fully substitute for synchronous fault current contribution.

EMT simulation has emerged as the standard approach for protection studies involving IBRs, offering point on wave analysis that positive sequence tools cannot provide. HIL testing is standard practice in the US for protection performance validation.

For Australian practice, the international evidence supports prioritising protection schemes independent of source characteristics, monitoring AI based protection development, specifying minimum fault current requirements for IBR installations, and adopting EMT simulation for protection coordination studies in weak grid areas of the NEM.

11. Task 7 – Remote Systems and Microgrids

Microgrids differ from conventional grids in three key areas: limited short-circuit strength, high penetration of IBRs, and frequent transitions between grid-connected and islanded operation [96], [97], [98]. Several studies examine the practical implications of these characteristics [97], [98].

Patel et al. [99] investigated the impact of control strategies on negative-sequence current detection. Their work showed that inverters operating under CSC often suppress negative-sequence components, causing directional elements in conventional relays to misidentify fault direction. Case-study reviews by Srivastava et al. [100] corroborated these findings, noting trip failures during high unbalance conditions in isolated microgrids.

Adewole et al. [101] demonstrated the use of RTDS to evaluate adaptive protection strategies in microgrids. Their study modelled a distribution network with solar, wind, diesel, and battery storage resources, incorporating islanding and network reconfiguration scenarios. Using RTDS in a HIL setup, the framework dynamically assessed adaptive relay algorithms under realistic operational dynamics, confirming coordination where fixed settings could fail. The work highlights the utility of RTDS for validating next-generation protection approaches in inverter-dominated, low-inertia systems.

Beikbabaei et al. [102] explored ML based protection schemes and reported that while ML algorithms could detect low-magnitude faults rapidly, limited historical fault data and communication latency in remote sites posed significant practical challenges. NERC [96] noted that while strong grids provide a stable reference for resources, weak grids can pose significant challenges for connecting inverter-based resources. Under weak grid conditions, issues may arise ranging from classical voltage instability to control instability and interactions, which can affect the performance of protection schemes and make even adaptive approaches sensitive to tuning.

In addition to advanced protection strategies, there exists a complementary class of physical solutions aimed at restoring traditional fault-current levels in microgrids. For instance, recent research has proposed several innovative approaches to address protection challenges in inverter-dominated microgrids. Ferrari et al. [103] demonstrated that grid-forming inverters can be modified to provide significantly higher fault currents, more than three times their nominal rating enabling the use of conventional overcurrent protection devices even in islanded operation.

In Australia, where negative-sequence current requirements are not explicitly defined as they are in the US, practitioners have observed inconsistent directional protection behaviour. This is particularly evident when integrating inverters from multiple manufacturers, each implementing slightly different sequence current responses and control strategies. Without alignment or coordination of these control behaviours, directional elements may misinterpret fault direction or magnitude, leading to protection misoperations.

In addition to variability in negative-sequence current, practitioners have highlighted that the lack of clear and comprehensive inverter performance specifications can further complicate protection coordination. Thomas Wearne CSIRO Energy highlighted that Energy Queensland has expressed considerable concern regarding the absence of standardised inverter specifications. He noted that manufacturers’ data sheets frequently omit critical information, particularly fault current magnitude and duration which is essential for effective protection coordination. To address this gap, he emphasised the need to establish minimum performance requirements to ensure consistent and reliable integration with protection systems.

Recent research trends seek to mitigate these issues through model-based relay adaptation. By continuously estimating inverter sequence impedance, relays can dynamically adjust directional element torque angles or switch between positive- and negative-sequence polarizing quantities depending on network state. PNNL [104] observed that adaptive relay settings can improve directional protection reliability in microgrids with mixed-control inverters, addressing issues caused by low or inconsistent negative-sequence currents.

Nguyen et al. [105] explored the integration of SynCons into distributed secondary control frameworks. By participating in voltage and frequency regulation alongside DERs, SCs enhance system strength, provide inertial response, and improve overall microgrid stability. Industry experience supports these findings: for example, Jake Saunders (PWC) noted that for large scale systems, SynCons remain the preferred option, as alternative technologies are still maturing and primarily targeted toward smaller networks. This aligns with broader field experience in weak-grid contexts, where SCs continue to offer a robust and commercially proven means of improving both stability and protection dependability.

Both approaches offer independent pathways for improving protection performance in weak-grid, inverter-heavy systems.

These experiences collectively demonstrate that limited fault currents, distorted waveforms, and dynamic control interactions introduce complexities that are largely absent in conventional synchronous grids. Field studies indicate that microgrid protection strategies must consider not only the instantaneous fault characteristics but also the underlying inverter control dynamics, mode transitions, and system strength limitations.

11.1 Fault Current Characteristics and System Strength Implications

The magnitude and duration of fault currents in inverter-dominated microgrids differ substantially from conventional synchronous grids, presenting fundamental challenges to protection design. [96] notes that fault currents from grid-following inverters are typically limited to 1.0–2.0 p.u. and decay within 2–5 cycles, in contrast to the sustained high currents from synchronous machines. Patel et al. [99] quantified this in a 100% inverter-fed microgrid testbed, showing that a line-to-ground fault on a lightly loaded feeder produced an initial fault current of only 1.2 p.u., which decayed to below 0.5 p.u. in less than 50 ms.

Mathematically, the fault contribution from an inverter can be expressed in equation 1*:*

$$I_{sc}(t) = I_{f,peak}e^{-t/\tau} + I_{ss}$$ equation 9[13]

where $\mathrm{I}_{\mathrm{f,peak}}$is the initial fault current determined by the inverter control limits, τis the decay constant associated with the control response, and $\mathrm{I}_{\mathrm{ss}}$is the steady-state current (often near zero in current-limited inverters) [106], [107].

Simulation studies performed by Sati et al. [108] on an islanded inverter-dominated microgrid within a Canadian urban distribution network demonstrated that conventional overcurrent relays, which rely on sustained fault current magnitudes, frequently failed to operate under rapidly decaying conditions. The maloperation was attributed to the combination of rapid fault current decay (I_sc(t) dropping below relay pickup thresholds within 2–3 cycles) and relay time–current characteristic curves designed for slower, sustained currents. Mathematically, if the relay operates according to an inverse-time characteristic:

$$t_{trip} = \left(k\frac{I_{pickup}}{I_{fault}} - 1\right)^{-n}$$ equation 10[14]

Where $I_{fault}$is the instantaneous fault current, $I_{pickup}$is the relay's threshold, and k, n are characteristic constants, then rapidly decaying inverter currents can fall below I_{pickup} before t_{trip} is reached, leading to missed trips. El-Sayed & Sati [107] highlighted that low short-circuit ratio (SCR) conditions exacerbate this effect, because the limited system strength further reduces initial fault currents, compounding the risk of non-operation.

El-Sayed & Sati [107] reported that in an islanded inverter-dominated microgrid, the initial fault current may reach approximately 1.5–2.0 p.u. but decays to near nominal levels within 40–60 ms. Conventional inverse-time overcurrent relays, which rely on sustained currents above their pickup thresholds, may fail to operate because the fault current falls below the threshold before the relay time delay is reached. This behaviour is particularly pronounced in weak or remote microgrids dominated by inverter-based resources.

Such observations directly inform the design of adaptive protection schemes, including the use of lower relay thresholds, faster-acting elements, or alternative sequence-based measurements, as explored in studies of microgrids with high inverter penetration [99], [108], [106]. Importantly, these findings illustrate how field experience and straightforward mathematical reasoning highlight the limitations of conventional relay logic in low-inertia, low-SCR microgrids, providing critical context for both researchers and practitioners developing next-generation protection approaches.

[13] Cited in foundational modelling literature, including B. K. Johnson & M. Ropp, *"Modeling Inverter Fault Current Contributions,"* IEEE Power and Energy Society (PES) General Meeting, 2019; and CIGRÉ Technical Brochure 859, *"Protection of Networks with Inverter-Based Resources,"* 2022.

[14] As defined in IEC 60255-151 and IEEE C37.112 for standard inverse-time overcurrent relay characteristics.

System strength, often quantified by the Short-Circuit Ratio (SCR), plays a critical role in relay sensitivity and stability. Srivastava et al. [100] reviewed multiple microgrid deployments and highlighted that weak-grid conditions can exacerbate interactions between inverter control dynamics and conventional protection schemes, necessitating carefully coordinated directional or sequence-based elements. Industry practitioners have observed complementary approaches to assessing system strength: Thomas Wearne from (CSIRO Energy) noted that frequency response analysis can offer valuable insight into system strength and source impedance, making it a useful component within protection schemes. However, its applicability is limited in complex, multi-source networks where fault conditions may not produce clear or consistent frequency characteristics. This method is most effective in simple system topologies where frequency deviations can be reliably correlated with specific fault events. Lyu, Xie & McDermott [104] further discussed how negative-sequence currents in inverter-based resources can impact relay performance, reinforcing the need for adaptive or setting-less protection strategies to maintain reliability during transitions between grid-connected and islanded operation.

These findings underline that fault dynamics, inverter control characteristics, and local system strength cannot be treated independently; their combined effect directly informs relay settings, protection scheme selection, and critical clearing times. In response, next-generation protection approaches have been developed. Real-time threshold adjustment and adaptive schemes have been explored in [108], [106] harmonic- or sequence-based fault detection has been studied in [106]; and algorithmic or model-informed approaches, including ML, have been proposed in [102], [100], [98]. These approaches dynamically respond to system conditions—such as islanding events, variable renewable injections, and low short-circuit strength—thereby maintaining protection reliability in inverter-dominated microgrids.

11.2 Adaptive and Setting-less Protection in Microgrids

As renewable penetration grows and network conditions become increasingly non-stationary, protection engineers face a central challenge: maintaining correct relay coordination under continually changing system impedance, generation mix, and fault current contributions. Adaptive and setting-less protection schemes have therefore emerged as a frontier research area — moving away from static, time–current or impedance-based thresholds toward algorithms that self-adjust in real time based on actual operating conditions.

A protection setting is only optimal for a single system state, and other states may introduce compromise. Recognizing this, the concept of adaptive protection has evolved over time through contributions from various researchers and practitioners. This principle is particularly critical in microgrids and isolated systems, where operational modes can shift rapidly between grid-connected, islanded, and partial-supply configurations. During such transitions, short-circuit currents may vary by an order of magnitude, rendering fixed relay settings ineffective or even unsafe.

Simulation studies by Sati et al. [108] on an isolated inverter-dominated microgrid illustrate this effect. They demonstrated that conventional overcurrent protection schemes can fail when inverter fault contributions are severely limited. Rapid fault current decay and persistent current limitation imposed by inverter control loops undermine the ability of traditional relays to reliably detect and clear faults. The inverters' inner current control loops imposed current-limiting behaviour defined approximately by:

$$i_{\text{fault}}(t) = i_{\max}(1 - e^{-\frac{t}{\tau_c}}) \qquad \text{equation 11}$$ [15]

where $i_{\max}$is the inverter's current limit (typically 1.1–1.3 p.u.), and $\tau_c$the control loop time constant, often 1–3 ms. As $\tau_c$determines how quickly the inverter reaches its current ceiling, fault currents effectively plateau rather than surge, leading to reduced magnitude and duration of overcurrent. The relay's definite-time element, calibrated for traditional electromechanical fault envelopes, therefore fails to accumulate sufficient current to trigger within the expected tripping window. A. Hooshyar et al. suggested that protection schemes should instead track the rate of change of current or employ impedance trajectories to detect inverter-constrained faults [109].

The simplified expression is intended only to illustrate the general effect of inverter current limiting on fault current magnitude and duration. Actual inverter fault responses may be significantly more complex, with modern control systems employing current prioritisation, fault ride-through functions, and sequence-dependent control strategies that can result in materially different positive-, negative-, and zero-sequence current behaviour. Consequently, protection-relevant fault signatures may vary substantially between inverter technologies and manufacturer implementations

Meanwhile, Adewole et al. [101] demonstrated a centralised adaptive protection framework for reconfigurable microgrids using a RTDS. The system continuously monitored network parameters, including breaker statuses, generation dispatch, and line impedances, to update protection settings across all relays in real time. Fault testing in a HIL configuration showed that their adaptive scheme-maintained coordination between feeder and bus relays under network reconfiguration — a scenario where fixed settings produced misoperations. The study highlighted that computational limits and communication latency were critical factors: if settings were recalculated too slowly or communication links introduced delays, the adaptive framework could not fully track the system dynamics.

Setting-less protection represents the next evolutionary step, eliminating the concept of predefined settings altogether. Impedance trajectory recognition, where relays analyse the instantaneous change of the apparent impedance $Z_{\text{app}}(t)$over time to classify fault types without fixed zones, has been proposed as a potential approach. Instead of relying on static mho or quadrilateral boundaries, the relay monitors the direction and curvature of the impedance trajectory. Faults are identified by characteristic signatures, such as a sharp inward trajectory toward the origin followed by flattening near a constant reactance value indicates a near-end fault limited by inverter control. This concept has been explored in theoretical studies, such as Niu et al. [110], which analyse the impedance trajectories under various current-limiting strategies in inverter-based systems.

[15] The inverter's current-limiting response imposed by its inner current control loops. As cited in B. K. Johnson & M. Ropp, 'Modelling inverter fault current contributions,' IEEE PES GM, 2019; CIGRÉ TB 859, 2022.

$$Z_{\text{app}}(t) = \frac{V(t)}{I(t)} = R(t) + jX(t)$$ equation 12[16]

Building on the challenges posed by inverter-constrained fault currents, adaptive differential protection strategies have been proposed for microgrids [106]. These approaches leverage sequence- or harmonic-based metrics rather than relying on fixed fault current magnitudes, allowing relays to detect faults more reliably under low short-circuit strength conditions. Significantly, the algorithm required no preconfigured fault current assumptions in contrast to traditional non-adaptive current-differential schemes, whose sensitivity and correct operation depend on assumed minimum fault levels derived from system studies.

The conceptual boundary between adaptive and setting-less protection is increasingly blurred. In modern designs, the adaptive engine continuously modifies its response to approximate "setting-less" behaviour within practical limits. For example, frequency-adaptive overcurrent elements can scale their pickup level proportionally to system frequency deviation:

$$I_{\text{pickup}}(t) = I_0(1 + k_f\,\Delta f(t))$$ equation 13[17]

where k_f is the adaptive coefficient. During inverter-induced frequency swings, this compensates for apparent current bias caused by frequency-dependent impedance shifts, reducing the likelihood of undesired trips.

Beyond the technical mechanism, adaptive and setting-less protection philosophies signify a broader transition in protection thinking, from discrete state logic to continuous system inference. Rather than reacting to a single measurement threshold breach, future protection systems are expected to interpret a multi-dimensional system state, incorporating current, voltage, impedance, frequency, and even inverter control signals to infer the most probable disturbance cause.

In Australia, the NER and AS 60044-series assume protection schemes operate with verified coordination margins, typically derived from studies encompassing minimum and maximum fault levels, network impedances, and generation mixes. Established approaches including group settings allow some variability; however, schemes that adjust thresholds dynamically in real time, without documented simulation-based or analytical studies defining the operational envelope across all credible conditions, present challenges for demonstrating compliance under current regulatory frameworks.

Collectively, the literature underscores that while adaptive and setting-less protection concepts have matured in research and limited field trials, their full-scale deployment remains constrained by the absence of established validation and compliance frameworks. Studies consistently highlight the need

[16] Apparent impedance seen by a protection relay during a fault, expressed as the ratio of measured voltage to current at the relay location, $Z_{\text{app}}(t) = V(t)/I(t) = R(t) + jX(t)$, as defined in IEC 60255-151 and IEEE C37.112.

[17] The frequency-dependent pickup current of a relay, as defined in IEC 60255-151 for frequency-dependent protection elements.

for protection systems that can maintain coordination and dependability under rapidly varying system conditions, yet existing standards and certification processes are structured around fixed, pre-verified settings. Bridging this gap between adaptive capability and regulatory assurance emerges as the central challenge identified across recent works.

11.3 Negative-Sequence Current Behaviour and Directional Protection

Protection coordination in microgrids becomes significantly more complex when IBRs dominate, as their fault current contributions deviate from the symmetrical characteristics of synchronous generation. As highlighted by Lyu, Xie, and McDermott [104], the magnitude and phase of negative-sequence currents depend strongly on inverter control design, particularly grid-following versus grid-forming mode.

Introducing variability that challenges the dependability of directional and phase-comparison protection elements Yu, Xie, and McDermott [44] observed in their Pacific Northwest National Laboratory (PNNL) study that the inverter current control strategy, whether CSC or decoupled sequence control (DSC), strongly influences the magnitude and phase of negative-sequence current injection during unbalanced faults. In CSC-based inverters, fault response is governed by a current reference constrained by converter ratings and internal current-regulation loops, resulting in a nearly symmetrical output with negative-sequence components typically below 3% of the positive sequence. By contrast, DSC-based inverters regulate voltage independently in each sequence frame, often producing negative-sequence currents of 10–15% under unbalanced load or fault conditions.

Mathematically, this distinction can be illustrated by comparing the current injection model under both control modes:

$$\begin{aligned}\text{CSC: } I_{\text{abc}} &= G_{\text{PLL}}(s)\, I_{\text{ref}}\, e^{j\theta} \\ \text{DSC: } I_{\text{neg}} &= K_{\text{seq}}(s)(V_2 - V_2^*)\end{aligned} \qquad \text{equation 14 [18]}$$

where I_{neg}represents the negative-sequence current, $K_{\text{seq}}(s)$the sequence control gain, and $V_2$the negative-sequence voltage component. The difference lies in whether the inverter seeks to track CSC references or regulate sequence voltages.

Field testing reported by PNNL [104] confirmed that directional overcurrent elements (67) and voltage-polarized phase relays (32V) suffered false directional reversals or underreach conditions in microgrids with mixed inverter control types. These effects were especially pronounced when inverters adopted voltage-forming (grid-forming) control during islanded operation. The apparent power angle measured by directional elements, normally a stable indicator of fault direction, became unreliable when the inverter's internal PLL lost synchronism or rapidly re-tuned following voltage dips.

Srivastava et al. [100] and Sharma & Sidhu [111] noted that in weak or islanded microgrids, negative-sequence current generation can be so low that directional protection may not operate reliably. In

[18] Current source control strategies for inverters, as described in Lyu et al. [108] and El-Sayed & Sati [106], which captures the sequence-dependent behaviour and control loop dynamics relevant to protection studies in microgrids.

one reported test on a remote hybrid microgrid, negative-sequence currents during an L–L fault remained well below the relay pickup threshold. Consequently, backup protection eventually cleared the fault, but the delay exceeded safe operational margins for inverter stability.

Emerging international standards, such as IEEE 2800 and VDE-AR-N 4120, have begun prescribing minimum negative-sequence current injection capabilities for grid-interactive IBRs to ensure reliable fault detection and system protection [104]. While the PNNL [104] study is US-based, in the Australian context, standards such as AS/NZS 4777.2 and the AEMO IBR Technical Performance Standards do not yet impose explicit quantitative requirements in this area. Instead, Australian standards focus on performance-based compliance, including voltage and frequency ride-through, reactive power control, and coordinated protection performance, leaving sequence current behaviour largely to manufacturer implementation.

In Australia, where negative-sequence current requirements are not explicitly defined as they are in the US, practitioners have observed inconsistent directional protection behaviour. This is particularly evident when integrating inverters from multiple manufacturers, each implementing slightly different sequence current responses and control strategies. Without alignment or coordination of these control behaviours, directional elements may misinterpret fault direction or magnitude, leading to protection misoperations.

Recent research trends seek to mitigate these issues through model-based relay adaptation. By continuously estimating inverter sequence impedance, relays can dynamically adjust directional element torque angles or switch between positive- and negative-sequence polarizing quantities depending on network state. PNNL [104] observed that adaptive relay settings can improve directional protection reliability in microgrids with mixed-control inverters, addressing issues caused by low or inconsistent negative-sequence currents.

11.4 System Stability and Protection Coordination in Weak and Isolated Grids

Protection and stability are closely linked in isolated power systems. NERC [96] and EPRI [97] highlight that fault clearing time and selectivity directly influence stability margins, particularly in low short-circuit ratio (SCR) microgrids. Unlike in strong grids, where protection acts largely as a passive responder, in low-SCR or inverter-dominated systems, relay and inverter interactions can directly affect voltage and frequency stability. In these contexts, protection operation becomes an active factor determining whether the microgrid survives disturbances.

Practical experience in remote and isolated systems reinforces these stability and protection challenges. Tennant Creek represents a more recent and technically sophisticated approach, developed in-house by PWC. Tennant Creek is one of three regulated power systems in the Northern Territory, alongside Darwin–Katherine and Alice Springs, and operates as a single-bus radial power system with five 22 kV feeders. Two of these feeders are very long and have been the source of significant operational challenges, highlighting the complexities of relay coordination and fault management in geographically dispersed, weak-grid networks.

In their 2017 report, NERC [96] highlighted that inverter-dominated systems with low short-circuit ratios exhibit significantly reduced stability margins compared with conventional synchronous systems. The report noted that fast-acting inverter control loops and low system inertia allow voltage and frequency to diverge rapidly following fault initiation. EPRI [97] extended this observation through time-domain simulations and HIL studies on weak-grid platforms, demonstrating that delayed fault clearing in such systems can markedly increase the risk of post-fault instability.

In inverter-dominated systems with low short-circuit ratios, protection performance directly influences system stability. NERC [96] observed that the inherently fast-acting inverter control loops and low system inertia allow voltage and frequency to diverge rapidly following fault initiation, reducing the margin for reliable fault clearing. In their 2018 report, EPRI [97] extended NERC's findings through time-domain simulations and HIL experiments on a weak-grid test platform. Their results demonstrated that modest increases in fault clearing delay could shift the post-fault system trajectory from stable recovery to voltage collapse, highlighting the sensitivity of inverter-dominated systems to protection timing and coordination.

The following conceptual expression illustrates these dependencies in a compact form:

$$\text{CCT} \propto \frac{H\ |V|^2}{|I_f| \cdot |Z_f| \cdot \tau} \qquad \text{equation 15}^{19}$$

where the term $|I_f|$ is strongly limited by the inverter's current ceiling (typically 1.1–1.3 p.u.), and τ reflects control and protection coordination delays. As H decreases and τ increases, CCT sharply reduces, leaving very little margin for protection delay, teleprotection latency, or reclosing logic. The practical implications of these reduced stability margins are frequently observed in remote and weakly interconnected power systems.

Practical experience in remote systems illustrates the operational implications of reduced stability margins in weak grids. One example is the Tennant Creek power system in the Northern Territory, developed in-house by PWC. Tennant Creek is one of three regulated power systems in the Northern Territory, alongside the Darwin–Katherine and Alice Springs systems. The network operates as a single-bus radial system supplying five 22 kV feeders, two of which are particularly long and have historically presented operational challenges. Operational investigations have indicated that high-impedance faults on these long feeders can produce severe system disturbances. Because the fault impedance prevents a full voltage collapse — typically reducing voltage to approximately 0.6 p.u.— the generation plant does not experience the event as a conventional short-circuit condition. Instead, the system behaviour resembles a sudden increase in electrical loading.

Under such conditions, generation units may approach overload limits and system frequency can decline rapidly. In some observed scenarios, the RoCoF reached values approaching 16 Hz/s, which

[19] Novel equation 15 not directly reported in [103], [109] but is constructed from fundamental relationships described in the literature (NERC [96], EPRI [61]) and common modelling approaches for inverter-dominated systems. Refer Appendix B – Conceptual Critical Clearing Time (CCT) Equation.

was sufficient to trigger multiple stages of UFLS or, in some cases, result in complete system blackout events. Protection coordination was also identified as a contributing factor. The feeder protection scheme includes multiple downstream reclosers requiring grading coordination with the bus feeder protection. This arrangement resulted in fault clearing times exceeding approximately 400 ms. Under the observed operating conditions, these clearing times exceeded the disturbance ride-through capability of the online generation, leading to generator trips, cascading outages, and repeated system-wide interruptions.

To address these challenges, the protection engineering team at PWC developed a hybrid protection approach drawing on concepts described in a 2021 Schweitzer Engineering Laboratories technical paper. The scheme applies logical AND coordination between a frequency-based element and an overcurrent element, with the objective of reducing fault clearing time to approximately 180 ms. Early implementations considered the use of a RoCoF element because it provides both magnitude and time-domain discrimination between fault-induced frequency deviations and conventional under-frequency events. However, testing indicated that the SEL-751 Feeder Protection Relay and SEL-751A Feeder Protection Relay required significant computation time to produce a stable RoCoF estimate when the rate of change exceeded approximately 2.5–3 Hz/s. In practice, this reduced the available time margin needed to achieve the target clearing time.

The scheme was therefore revised to employ a conventional under-frequency element combined with an overcurrent element. Correlation analysis of historical events suggested that high-impedance faults on the long feeders were consistently associated with rapid frequency deviations. An overcurrent pickup of approximately 400 A was selected to distinguish fault conditions from normal loading, which was feasible because the feeders typically operate at currents below approximately 200 A. The hybrid protection logic operates in parallel with the existing overcurrent protection and UFLS schemes, providing an additional layer of protection without requiring modification of the existing arrangements.

The revised protection settings were implemented several months prior to the industry consultation. Since implementation, one fault event has been recorded and cleared in approximately 80–100 ms, representing a substantial reduction from the previous clearing times exceeding 400 ms. The fault was isolated to the affected feeder, no system-wide load shedding was triggered, and normal operating obligations were maintained. While these initial results are encouraging, the approach remains under evaluation pending additional operational experience.

El-Sayed [107] conducted a simulation and HIL study replicating weak-grid conditions typical of remote mining operations such as those found in the Australian outback. Their harmonic-adaptive coordination scheme was tested under varying penetration levels of solar PV and battery storage. The study found that relay coordination margins below one cycle (<20 ms) could still preserve stability — but only when the inverter PLL maintained synchronization and the current-limiting algorithm preserved a minimum reactive current contribution during faults. When PLL desynchronization occurred, the inverters lost voltage reference and reactive current support, reducing the effectiveness of protection actions and increasing the likelihood of post-fault instability.

In the NEM, the NER — specifically clause S5.1a.8 — prescribe maximum fault clearance times linked to voltage level, ranging from 80 ms at 400 kV and above to 120 ms at 100–250 kV. These limits underpin protection design for system stability. However, for isolated or non-market networks such as mine sites and islanded microgrids, no equivalent regulatory prescription exists. In such cases, appropriate clearing times are established empirically through staged-fault testing or dynamic simulation, consistent with methodologies described by NERC [96] and EPRI [97].

Recent simulation research by Srivastava et al. [100] and Beikbabaei et al. [102] has advanced the concept of stability-informed protection coordination, in which relay time–current characteristics are dynamically adjusted based on real-time indicators of system stability. These approaches aim to align protection performance with instantaneous grid conditions, ensuring that relay operations remain both selective and stability-preserving under varying levels of inverter penetration and system strength.

In summary, theoretical and simulation studies from NERC [96], EPRI [97], El-Sayed and Sati [106], Srivastava et al. [100], and Beikbabaei et al. [102] consistently reinforce the interdependence between protection timing and system stability. Collectively, these works demonstrate how relay operating times interact with inverter control dynamics, system inertia, and coordination delays to influence post-fault recovery. While field validation remains limited and highly site-specific, current practice in Australian microgrids typically relies on empirically derived clearing times established through simulation, staged-fault testing, and engineering judgement, guided by observed inverter behaviour, local network configurations, and relevant performance standards.

11.5 Machine Learning and Intelligent Protection for Isolated Systems

Recent advances in ML are redefining microgrid protection, offering pathways beyond deterministic relay coordination. Uzair et al. [98] developed a data-driven protection scheme for low-voltage AC microgrids dominated by inverter-interfaced distributed generation (IIDG), where conventional relays often fail due to low and variable fault currents. Their approach used realistic, simulation-derived voltage, current, and inverter state measurements to train a neural-network-based classifier capable of detecting and classifying faults with high precision. From extensive fault and non-fault datasets, 100 descriptive features including two novel indicators, the *Peaks Metric* and *Max Factor* were extracted to capture subtle waveform distortions unique to inverter-driven transients.

Traditional overcurrent relays often misoperate when inverter outputs reach their current-limiting threshold (clipping), reducing sensitivity and selectivity. By contrast, Uzair et al.'s [112] ML-based relay dynamically adapts to changing operating conditions, with the Random Forest classifier achieving over 98% accuracy and near-instantaneous response.

Unlike fixed time–current characteristic schemes, this method *learns* system behaviour, inferring fault conditions from data patterns rather than static thresholds. It marks a decisive step toward *setting-less* protection where decision-making is guided by statistical intelligence and adaptive inference offering a robust solution for weak-grid and inverter-dominated environments.

Ali et al. [113] expand this perspective in a comprehensive review of intelligent protection strategies for microgrids and isolated systems, highlighting the emergence of ML, deep learning (DL), and multi-agent systems (MAS) as the next frontier. Their analysis identifies key functional trends: advanced feature extraction (via Wavelet, Fourier, or Hilbert–Huang transforms) to capture transient and harmonic signatures; the proven resilience of Random Forest , Boosted Trees, and Support Vector Machines (SVM) when coupled with wavelet-based features; and the growing potential of deep neural networks (DNNs) including convolutional and recurrent models for real-time fault identification, albeit with higher computational and data demands.

Beyond individual classifiers, Ali et al. [113] emphasize the enabling role of micro-PMUs (μPMUs) and MAS frameworks for decentralised, cooperative decision-making. μPMUs provide high-resolution, time-synchronised data, while MAS architectures allow intelligent electronic devices to autonomously coordinate fault isolation and service restoration. Together with adaptive relay recalibration, these systems enhance both protection sensitivity and coordination, essential in isolated or weakly meshed networks.

However, both authors caution that many AI-based approaches remain confined to simulation. Challenges persist around data availability, interoperability, cybersecurity, and communication latency. Challenges persist around data availability, interoperability, cybersecurity, communication latency, and the collection of representative training datasets capable of capturing the highly variable fault behaviour associated with different inverter control architectures. Hybrid frameworks that fuse conventional and intelligent schemes retaining the dependability of hardware-based logic while exploiting ML adaptability are emerging as a practical bridge toward real-world implementation.

Taken together, these studies signal a paradigm shift: protection systems are evolving from static responders into adaptive agents capable of continuous learning and contextual decision-making. While still experimental, ML-based protection offers a compelling vision for future microgrids combining speed, selectivity, and resilience under the dynamic conditions characteristic of inverter-dominated and isolated power systems.

12. Task 8 – Subsynchronous Oscillations

12.1 Introduction

A class of stability challenge that was largely absent from networks dominated by synchronous generation has been introduced in the NEM. Among the most consequential is the emergence of subsynchronous oscillations (SSOs): sustained energy exchanges between power system components at frequencies below the fundamental 50 Hz. The particular characteristics of IBR driven subsynchronous oscillations present a qualitatively different risk profile that demands updated assessment methods, regulatory frameworks and mitigation strategies.

The AEMC has explicitly recognised this challenge, noting the importance of enhancing the NER frameworks to define acceptable limits of subsynchronous power system oscillations in the NEM [114]. AEMO’s 2025 TPSS reinforces this position, identifying the management of oscillatory stability as a priority as the NEM transitions to higher levels of IBR penetration [115]. The operational events in the WMZ between 2018 and 2023, detailed in Section 12.5, served as a landmark demonstration that legacy stability assessment approaches are insufficient for high IBR penetration scenarios [116] [117].

These events, together with analogous international experience in the United States, China, the United Kingdom and Canada (Section 12.8), have catalysed a global shift toward frequency domain analysis, impedance-based screening and dedicated on site protection systems.

12.2 Definition and Frequency Spectrum

Subsynchronous oscillations describe energy exchanges between power system components at frequencies below the synchronous frequency. Historically, monitoring concentrated on electromechanical oscillations in the 0.1 Hz to 5 Hz range, associated with the swing dynamics of synchronous machine rotors. In contemporary IBR dominated grids, the critical phenomena have shifted into the 5 Hz to 45 Hz spectrum, driven by the fast-acting control loops within power electronic converters [118] . If left undamped, these oscillations can grow in magnitude, triggering protection systems and potentially disconnecting significant generation capacity.

12.3 Classification of SSO Phenomena

12.3.1 Classical Subsynchronous Resonance

Classical SSR describes interactions between synchronous generators and series compensated transmission lines through two primary mechanisms. The Induction Generator Effect (IGE) occurs where the machine presents a negative resistance at subsynchronous frequencies; should this effective negative resistance exceed the positive resistance of the network, an unstable resonance develops. (TI) involves alignment of the electrical resonance frequency with natural torsional modes of the turbine generator shaft, potentially causing mechanical fatigue.

12.3.2 Subsynchronous Control Interaction

In the modern power system, the predominant form of subsynchronous instability is Subsynchronous Control Interaction (SSCI). This describes interactions involving power electronic devices, including IBRs, HVDC links and reactive compensation equipment, driven by high bandwidth control loops (particularly PLLs and current regulators). The critical distinction from classical SSR is that SSCI involves IBR controls generating negative resistance across a broad spectrum of frequencies, making system stability dependent on the generator’s operating point and its interaction with other nearby IBRs.

The NEM’s SSO challenges have been predominantly SSCI related [116], confirming a structural shift in stability drivers from passive network component design toward the tuning and behaviour of active IBR control systems. CIGRE Technical Brochure 909 (2023) provides internationally recognised guidelines for SSO studies in power electronics dominated systems, reinforcing this analytical consensus [4] .

12.4 Regulatory Framework

12.4.1 NER Clause S5.2.5.10

Clause S5.2.5.10 of the NER ('Detection and response to unstable operation') imposes a non-negotiable obligation on all connecting generating systems and reactive plant to implement protection schemes capable of reliably detecting the onset of unstable operation and taking appropriate protective action [119]. This clause establishes the fundamental regulatory framework for the detection and management of unstable operation in the NEM, including instability arising from subsynchronous oscillations and inverter-driven control interactions

Implementation has been challenging due to ambiguity. AEMO has formally acknowledged significant uncertainty regarding the exact technical expectations, particularly for asynchronous generating systems and large power electronic equipment [120]. Key areas where clarity remains under development include: defining quantitative thresholds for instability; establishing consistent verification methods; determining sufficient test evidence; and setting pass/fail criteria for regulatory compliance.

A related challenge is that many of the quantities used to assess system strength and control-system stability do not translate directly into protection engineering outcomes. While oscillatory behaviour, phase-angle dynamics, and inverter control interactions may indicate emerging instability, there remains limited guidance on how these observations should be interpreted in terms of protection performance, operational risk, or regulatory compliance. This disconnect contributes to uncertainty regarding how S5.2.5.10 compliance should be demonstrated and validated in inverter-dominated power systems.

12.4.2 Protection Implications of SSO and SSCI

Subsynchronous oscillations present a fundamentally different protection challenge from conventional power system faults. Traditional protection systems are designed to detect abnormal electrical conditions such as short circuits, equipment failure, overloads, loss of synchronism, and sustained voltage or frequency deviations. These functions typically rely on observable changes in current magnitude, voltage magnitude, impedance trajectories, phase angles, or frequency. By contrast, Subsynchronous Control Interaction (SSCI) can develop as a dynamic control-system instability between inverter-based resources and the network, often without the distinct fault signatures upon which conventional protection systems depend.

This distinction is particularly important in inverter-dominated power systems. During an SSCI event, individual IBRs may remain electrically connected and continue operating within their fundamental-frequency operating limits while simultaneously participating in an unstable oscillatory mode at a subsynchronous frequency. As a result, conventional overcurrent, distance and differential protection schemes may neither detect nor respond to the underlying instability, despite the potential for escalating system-wide consequences.

The protection obligation associated with these phenomena is captured within NER Clause S5.2.5.10, which requires generating systems and dynamic reactive plant to detect unstable operation and take appropriate protective action. Unlike conventional fault protection requirements, however, the application of S5.2.5.10 to SSCI and other inverter-driven oscillatory phenomena remains an evolving area of industry practice. While the obligation to detect and respond to unstable operation is clear, the specific protection philosophy, detection methodology, performance requirements and compliance assessment processes remain under development.

Industry experience has shown that compliance is frequently demonstrated through a combination of design studies, EMT simulations, controller tuning and operational risk assessments rather than through the deployment of dedicated oscillation protection systems alone. Consequently, a gap currently exists between the regulatory requirement to detect unstable operation and consistent industry guidance regarding the protection functions required to satisfy that obligation. This challenge has become more pronounced as oscillatory instability mechanisms increasingly shift from classical SSR phenomena toward SSCI mechanisms driven by inverter control interactions.

To address this emerging risk, utilities, system operators and equipment manufacturers are increasingly adopting dedicated oscillation detection and monitoring capabilities. These may include frequency-domain monitoring, spectral analysis, PMU-based oscillation detection, high-speed disturbance recording, plant-controller-based instability detection algorithms, and specialised SSO protection relays. Unlike conventional fault protection, these systems are designed to identify growing oscillatory energy within defined frequency bands and initiate an appropriate response before instability threatens plant integrity or broader power system security. Responses may range from alarming and operational intervention through to automated control actions or plant disconnection where unstable operation is confirmed.

The West Murray Zone events demonstrated the practical significance of this issue within the NEM. These events highlighted that conventional measures of system strength and traditional protection assessment methodologies may fail to identify emerging oscillatory instability risks, reinforcing the need for dedicated assessment, detection and protection frameworks capable of addressing inverter-driven subsynchronous oscillations. The lessons learned from West Murray have subsequently influenced both AEMO's development of frequency-scanning methodologies and the broader industry focus on oscillation detection, protection and compliance under NER S5.2.5.10.

12.5 Operational Experience: The West Murray Zone

The WMZ incidents between 2018 and 2023 provide the definitive Australian case study for SSCI. Two distinct IBR driven oscillation incidents were documented: an 8 Hz event and a separate sustained oscillation at approximately 17 Hz involving several solar farms [116]. AEMO’s July 2025 analysis provides a comprehensive account of the root causes and analytical techniques applied.

AEMO and NREL jointly conducted impedance-based stability analysis using site specific, black boxed IBR models in PSCAD/EMT simulation environments [121]. The findings were significant:

- The instability was not caused by low short circuit ratio (SCR) in the conventional sense, but by complex interactions between inverter control systems at non fundamental frequencies.
- The instability emerged when irradiance levels were low and the IBRs’ control bandwidths overlapped, producing a negatively damped resonance mode in the 17 to 23 Hz range.

- AEMO identified the source of the 8 Hz oscillations through EMT simulations and eliminated them through controller retuning with the inverter OEM.

These findings exposed a critical weakness in existing regulatory practice: while weak system conditions and reduced SCR may increase coupling between inverter controls and the network, SCR and other steady state measures do not adequately capture the dynamic coupling interactions that leads to SSCI. Compliance assessments conducted under NER S5.2.5.10 may confirm "stable" operation based on fundamental frequency criteria while overlooking frequency specific instability mechanisms. This represents a regulatory gap that the frequency scanning methods described in Section 12.6 are designed to address.

12.6 Frequency Scanning: Analytical Methods and AEMO's Initiative

The analytical limitations exposed by the WMZ events have increased industry interest in frequency-domain and impedance-based assessment techniques as complementary tools for identifying control interactions in IBR-dominated power systems. The WMZ events highlighted the value of these techniques for identifying controller-driven oscillatory interactions in IBR-dominated power systems. In response, AEMO has developed its frequency-scanning initiative to complement existing stability assessment methodologies and provide additional insight into potential subsynchronous interactions and controller-driven oscillatory modes. Consistent with international guidance, frequency scanning is best viewed as a complementary technique alongside established approaches including eigenvalue analysis, small-signal studies and EMT simulations, with each method providing different insights into system behaviour and oscillatory stability [4], [116], [117], [122]. In Australia, AEMO has led the practical application of frequency-domain assessment techniques through its frequency scanning initiative, providing an additional assessment method for identifying controller-driven oscillatory interactions that may not be readily observable through traditional system-strength metrics alone.

12.6.1 The Grid Impedance Scan Tool

The Grid Impedance Scan Tool (GIST), developed by the NREL with support from the U.S. Department of Energy's Wind Energy Technologies Office, represents a foundational advance in SSO risk assessment [123], [124]. GIST operates on impedance-based stability theory, assessing IBR–grid interactions across a wide frequency range. Unlike time domain simulations requiring specific disturbances to be applied, impedance-based methods proactively identify resonance conditions before they manifest operationally.

12.6.2 AEMO's Frequency Scanning Proof of Concept

In 2024mid-2024, AEMO initiated a four-stage frequency scanning proof of concept, recommended by the Power System Analysis Tools – Future Requirements independent review (authored by Tim George, August 2024) [125]. That review specifically identified frequency scanning as a critical capability for managing the risks associated with high IBR penetration.

12.6.2.1 AEMO Proof of Concept Stages

- Stage 1 Validation using known (white box) and encrypted (black box) IBR models.

- Stage 2 Controller design for stability in a single machine infinite bus configuration.
- Stage 3 IBR controller design in whole of NEM model.
- Stage 4 Generator connection project trial using up to four active projects.

As of late 2025, Stages 1 through 3 are complete. Stage 4 (active project trials) is underway [126].

The demonstrated outcomes are:

- Oscillations associated with IBR design can be identified early in the connections process.
- Connecting parties can design IBR controllers to reduce oscillation risk at a specific network location without access to restricted NEM wide models.
- The approach uses existing PSCAD models without exposing OEMs to additional intellectual property risk.
- Consistent results have been obtained across multiple frequency scanning tools in the market, including open-source tools.

12.6.3 AEMO's In House Tool: FAST

AEMO has developed its own in-house frequency scanning tool, the Frequency domain Admittance based Stability Tool (FAST) [126]. FAST is available on request from AEMO for use by connecting parties and their consultants. The availability of multiple compatible tools, including open-source options, provides the industry with vendor flexibility while ensuring analytical consistency.

12.6.4 Analytical Foundation: The Generalised Nyquist Criterion

AEMO's July 2025 report describes the analytical foundation underpinning the frequency scanning approach [125]. The method applies the Generalised Nyquist Criterion (GNC) to visualise controller stability. If either eigenvalue of the system's return ratio encircles the point of instability (−1, 0) on the GNC diagram, the generating system is unstable for that operating condition. This provides a clear, quantitative method for assessing controller stability. Where a case is identified as marginally stable, additional tuning moves eigenvalues further from the instability point, ensuring robustness under challenging conditions such as transmission line outages.

12.6.5 November 2025 Report: Detailed Methodology

AEMO's second frequency scanning report (November 2025) provides the methodology of each proof-of-concept stage, validation of results and initial learnings from applying frequency scanning tools [122]. This report represents the most comprehensive publicly available documentation of the practical application of frequency scanning to NEM connection assessments.

12.6.6 Integration into the Connections Process

AEMO has established frequency scanning as a focus area within its connection resources framework [122]. While not yet mandatory, AEMO notes that frequency scanning could help connecting parties and NSPs de risk the generator connections process. Current implementation includes:

- Application of frequency scanning for connection enquiries in identified weak grid regions.

- Impedance based analysis for assessing control interactions between proposed IBRs and existing generation.
- Integration of frequency scan results into GPS negotiations.
- Development of standardised methodologies for interpreting outputs in the context of NER compliance.

AEMO's stated position is that frequency scanning introduces a methodical tuning process that reduces the risk of issues emerging in the whole of NEM EMT studies during the full assessment process, and mitigates against unidentified SSO interactions arising in real time operations. With the NEM needing to approximately treble its capacity by 2050 [125], the efficiency gains from early identification of control system risks are material.

12.7 Mitigation Strategies

12.7.1 Technical Assessment Requirements

The minimum standard for future grid connections should comprise:

- Mandatory EMT simulation using PSCAD for electromagnetic and control dynamics.
- Frequency domain impedance scanning using GIST, FAST or equivalent [126].
- Multi scenario dispatch and contingency analysis covering the full operational envelope.
- HIL validation for critical installations.

12.7.2 Inverter Control Tuning

Control system tuning is the primary line of defence. The WMZ experience demonstrated that default settings optimised for strong grids can produce instability in weak grid conditions, particularly at low power output where control gains are highest. AEMO's proof of concept has demonstrated that the tuning process can be systematised and made more efficient using frequency domain methods [127].

12.7.3 Grid Strength Enhancement

Technologies include SynCons for fault current contribution and inertial support, and grid-forming inverters for autonomous voltage control and superior damping. AEMO's 2025 system strength assessments confirm the importance of delivering these services, noting lead times of five or more years for many assets [114].

12.7.3.1 On Site Detection and Protection

Grid connections located in areas with elevated SSCI or SSO risk should incorporate suitable instability detection and response capabilities, which may include:

- Real-time monitoring of voltage and current oscillations at the POC.
- Configurable frequency range detection (0.1 Hz to 25 Hz minimum).
- Multi-level response hierarchy including data logging, alarming, control-based mitigation actions and, where required, automatic tripping.
- Threshold settings transparent to Transmission Network Service Providers (TNSPs) and AEMO.

- Remote configuration and suppression capabilities based on assessed risk.

12.8 International Experience

Australia's SSO challenges are replicated internationally. A comprehensive IEEE survey documents at least nineteen significant SSO incidents across multiple continents between 2007 and 2022. The following experience provides context and validation for the analytical and mitigation approaches recommended in this report.

12.8.1 United States: ERCOT

The Electric Reliability Council of Texas (ERCOT) documented the first wind farm SSCI event in 2009 (approximately 24 Hz oscillations involving Doubly-Fed Induction Generator (DFIG) and series compensated lines) [128], followed by three further events in 2017 (22 Hz to 26 Hz range), resolved through converter control updates. In October 2024, ERCOT formalised SSO screening and detailed study requirements, mandating impedance based analysis and PSCAD modelling for new connections in areas with series compensation [129].

12.8.2 United States: NREL and EPRI

NREL's GIST has become a reference capability internationally, with partnerships including GE Vernova for grid-forming wind turbine demonstration. NREL operates the ARIES platform for MW scale HIL testing [124]. EPRI held its first dedicated SSO Workshop in April 2023. The IEEE PES IBR SSO Task Force (established 2017) coordinates ongoing international research [130].

12.8.3 China: Wide Area Monitoring

China has experienced some of the most severe IBR related SSO events globally. The Guyuan wind system (Hebei Province) experienced hundreds of events from 2011 onwards; in one incident, over a thousand wind turbines tripped [131]. At Hami (Xinjiang, July 2015 [132]), the IBR triggered oscillation frequency matched the torsional frequency of nearby turbo generators, tripping three 660 MW units [133]. In response, Chinese researchers deployed a Subsynchronous Wide Area Monitoring System (SWAMS) incorporating dedicated subsynchronous PMUs and centralised dynamics analysis for real time SSO detection and source location [131].

12.8.4 United Kingdom

In August 2019, a transmission circuit fault triggered approximately 9 Hz oscillations at the Hornsea offshore wind farm, contributing to a major power system disturbance affecting over one million consumers [124]. Across Europe, oscillations from several hundred Hz to 800 Hz have been observed in offshore wind farms due to converter and collector cable interactions [118].

12.8.5 Canada

In 2015, Hydro One observed 20 Hz oscillations at a 44 kV feeder upon switching in a capacitor bank where three 10 MVA solar PV plants were connected [118]. This demonstrates that SSCI can occur at distribution voltage levels with relatively modest IBR installations.

12.8.6 CIGRE International Guidelines

CIGRE Technical Brochure 909 (October 2023) provides internationally accepted guidelines covering screening studies, impedance scan methods, frequency scanning, EMT simulation and eigenvalue analysis for SSO in power electronics dominated systems [4]. This document represents current international best practice and is directly applicable to NEM connection studies.

12.9 Conclusions and Strategic Recommendations

The WMZ incidents confirmed that the transition to a high IBR grid requires a fundamental departure from legacy stability assessment methods. AEMO's frequency scanning initiative, supported by the July and November 2025 reports and the development of the FAST tool, represents validated and significant progress toward addressing this challenge. The following strategic recommendations are proposed.

1. Impedance Based Screening: GIST, FAST or equivalent tools are required for GPS and connection assessments in weak grid areas, including pre-convention screening, post-commission validation and direct application of results to OEM controller tuning.
2. **Investment in Grid-forming Capability:** Strategic placement of grid-forming inverters and SynCons in identified weak grid zones to provide improved damping, foundational system strength and adequate fault current contribution.
3. **Institutionalise Adaptive Control Review:** Mandatory post commissioning review and update of IBR control settings, linked to routine impedance scanning to maintain continuous technical compliance as network conditions evolve.
4. **SSO Instability Detection and Response**: Grid connections should implement suitable instability detection and response capabilities, including oscillation monitoring, control-based mitigation measures and, where necessary, dedicated protection functions. Nationally consistent guidance should be developed to support compliance with NER Clause S5.2.5.10.
5. **National Harmonisation:** Consistent standards must be adopted across all NEM regions to eliminate the current fragmentation in SSO risk management.

A key observation arising from this review is that subsynchronous oscillations and inverter-driven control interactions challenge conventional protection philosophies. Unlike faults, SSCI events may develop without the current, voltage or impedance signatures traditionally used by protection systems. Consequently, compliance with NER Clause S5.2.5.10 increasingly relies on a broader set of instability detection and response capabilities, including oscillation monitoring, controller-based mitigation, active damping functions, operational constraints, wide-area monitoring systems and, where required, automated disconnection strategies.

While NER Clause S5.2.5.10 establishes clear obligations for detecting instability and responding appropriately, industry practice continues to evolve regarding the preferred methods for identifying oscillatory instability and demonstrating compliance. The West Murray Zone experience highlighted the growing importance of supplementary assessment, monitoring and response capabilities capable of addressing inverter-driven oscillatory phenomena that may not be readily identifiable through conventional protection approaches.

Accordingly, further industry collaboration is recommended to develop nationally consistent guidance covering:

- instability detection methodologies;
- oscillation monitoring and alarming requirements;
- acceptable mitigation and response strategies;
- performance requirements for instability detection systems;
- testing and validation methodologies; and
- compliance demonstration processes under NER Clause S5.2.5.10.

13. Industry Response Analysis

The industry response to protection challenges in IBR-rich networks is neither conceptual nor speculative; it is grounded in practical experience across NSPs, protection equipment manufacturers, system operators, and research institutions engaged throughout this study. The findings presented in this report demonstrate a broadly convergent shift in how protection is being designed, applied, and adapted in response to declining fault levels, variable inverter behaviour, and increasing system complexity.

Evidence from Current Practice

Across participating NSPs, a clear hierarchy of protection approaches has emerged, although its application remains strongly dependent on system context. Line current differential protection is consistently identified as the most reliable primary scheme in weak or IBR-dominated networks where communication infrastructure and system topology support its deployment, due to its relative independence from fault current magnitude and directional characteristics. This position is explicitly supported by Transpower, TasNetworks, and Powerlink, and reinforced by OEM capability development.

However, evidence from microgrid and remote system applications, including BEC Engineering case studies, demonstrates that practical constraints such as limited communications infrastructure, relay capability, and system scale result in continued reliance on conventional time-current grading schemes for the majority of protection functions. In these environments, differential protection is typically applied selectively to critical assets such as generators and large transformers, while overall system protection is achieved through settings group selection, mode-dependent coordination, and simplified grading philosophies.

Consequently, conventional overcurrent, directional, and distance elements remain widely deployed across the broader network, but are increasingly adapted to maintain reliability under evolving system conditions. This adaptation is evident in multiple forms across the participating NSPs. Endeavour Energy reports the application of voltage-controlled overcurrent schemes and modified directional elements to manage reverse power flow and address reduced confidence in fault detection near IBRs.

Powerlink describes differential protection as the preferred primary scheme in weak grid environments, with distance protection retained primarily for backup functions. Where applied, distance elements utilise measures such as weak infeed logic, which Powerlink reports is enabled at line ends in weak grid areas with low fault current contribution. Transpower similarly identifies that conventional directional and distance elements, including those incorporating weak infeed logic, are identified as requiring requalification and mitigation as IBR penetration increases. In more constrained or remote systems, PWC has implemented hybrid schemes combining frequency and overcurrent elements to accelerate fault detection where conventional grading is insufficient.

At the transmission level, communication-assisted approaches, including intertripping and differential schemes supported by diverse communications, are applied by TasNetworks and other operators where communication infrastructure is available. These approaches are complemented by the application of synchrophasor-based wide-area monitoring and protection support functions, as reported by Powerlink and Energy Queensland.

Operational experience confirms that traditional protection assumptions are no longer universally valid. NSPs including Endeavour Energy, Energy Queensland, and PWC report consistent challenges associated with low and variable fault current, suppressed or inconsistent negative sequence behaviour, and increasing uncertainty arising from inverter behaviour and control-dependent system responses. Endeavour Energy in particular highlights risks associated with software-defined inverter responses and limited transparency in fault characteristics. These observations align with the broader issue identified by CSIRO subject matter experts regarding the lack of standardised and transparent inverter fault response specifications. Across multiple contributors, the absence of reliable and consistent data describing fault current magnitude, duration, and phase behaviour is identified as a critical barrier to effective protection design, coordination, and validation.

OEM engagement indicates that artificial intelligence is not currently integrated into primary protection tripping functions, with identified implementations such as AI-assisted fault detection functions limited to assistive roles within conventional protection algorithms. Industry engagement with OEMs and international research bodies such as NREL is consistent in identifying AI-based protection as an active area of development, with anticipated future deployment contingent on achieving the levels of determinism, transparency, and validation required for protection applications.

Converging Industry Position

The combined findings from NSPs, OEMs, and research organisations indicate a convergence around several key principles:

- First, fault current can no longer be treated as a dependable primary indicator for protection. Across contributors, the magnitude, duration, and sequence composition of inverter fault current are shown to be insufficiently consistent to support traditional protection methods without modification.
- Second, system behaviour is increasingly governed by control systems rather than physical machine characteristics. Inverter responses are software-defined, proprietary, and variable

between manufacturers, creating a fundamental shift from physics-based to behaviour-based system dynamics.

- Third, protection systems must operate under conditions of reduced observability and increased uncertainty. Weak grid conditions, coupled with rapid control interactions and mixed technology fleets, result in degraded signal quality and reduced discrimination between fault and non-fault events.

These themes are reflected across field experience, manufacturer input, and academic research, indicating that they represent fundamental characteristics of the evolving power system rather than isolated issues.

Transitional Approaches Emerging in Practice

In response to these challenges, the industry is not abandoning existing protection paradigms, but is progressively adapting them through the introduction of hybrid, adaptive, and behaviour-aware approaches. Evidence from multiple NSPs demonstrates that this transition is already underway.

Hybrid protection schemes combining multiple indicators are being deployed in selected applications. PWC's implementation of a frequency and overcurrent-based scheme in Tennant Creek, targeting accelerated fault clearing times, represents a practical example of augmenting conventional protection with additional dynamic system indicators. Similarly, Horizon Power reports the use of mode-dependent settings groups to maintain protection sensitivity across operating modes, while Energy Queensland describes the application of adaptive operating strategies, including DERMS and system-level control, to manage changing system conditions.

These approaches are complemented by the application of communication-assisted protection schemes, including intertripping and distributed differential protection in transmission networks, as reported by Powerlink and TasNetworks, as well as the application of synchrophasor-based monitoring and wide-area visibility tools by Powerlink and Energy Queensland. OEM developments in time-domain and travelling-wave protection further illustrate the shift toward methods that operate independently of traditional phasor-based assumptions. While these techniques are proven and deployed at transmission level, particularly on long overhead lines, their application in sub-transmission and distribution systems remains limited to pilot deployments. Practical challenges—including signal attenuation, reflections from mixed overhead-cable circuits, and the complexity of multi-node meshed networks—currently restrict their reliable application in these environments.

Collectively, these developments indicate the emergence of a transitional protection architecture in which:

- conventional protection elements remain the primary tripping mechanism,
- but are increasingly supported by supervisory logic, additional measurement domains, and system-level indicators.

This layered approach reflects a pragmatic adaptation strategy, enabling existing systems to remain operational while progressively incorporating new capabilities.

Alignment with Emerging Research Directions

Emerging academic research provides a complementary perspective to the industry observations outlined in this report, particularly in relation to inverter control behaviour and its influence on system response during disturbances. Research programs across Australian universities—including the University of Melbourne, Monash University, the University of Queensland, the University of New South Wales, Curtin University, and others—collectively highlight several converging themes aligned with industry needs. These include the role of control system dynamics—particularly PLL behaviour—in shaping fault response, the influence of grid-forming and grid-following control strategies on voltage and frequency behaviour during disturbances, and the use of wide-area measurement and data-driven approaches to improve system observability in weak grid conditions.

Notably, research into PLL dynamics shows strong correlation between loss of synchronism, rapid phase angle variation, and transient instability during fault and near-fault conditions, while studies into inverter control strategies demonstrate that fault response is increasingly governed by internal control states rather than steady-state electrical quantities. In parallel, research into adaptive and hybrid protection approaches, including multi-signal and system-aware methods, reflects the same layered adaptation strategies already observed in operational practice.

This convergence of academic insight and operational experience indicates that meaningful information relevant to protection performance exists within inverter control dynamics, which is not currently captured by conventional measurement-based approaches. The structured interpretation of such dynamic control-state behaviour represents an emerging area of investigation, with potential to complement existing protection systems through additional supervisory signals.

Together, these research directions reinforce the limitations of conventional phasor-based protection approaches identified by industry and identify a set of structured gaps in translating these insights into practical protection solutions. These include the lack of standardised models describing inverter control behaviour, limited access to high-resolution operational data required for validation, and the absence of agreed frameworks for incorporating dynamic control-state information into protection decision-making. Collectively, these identified gaps define a clear and actionable research pathway, highlighting opportunities for coordinated industry and research collaboration to bridge the current disconnect between observed system behaviour and existing protection methodologies.

Forward Outlook

A key observation emerging from both industry engagement and operational experience is that the impact of increasing IBR penetration on protection systems is not uniform. Rather than a step change in performance, traditional protection schemes exhibit a progressive degradation in reliability aligned with their dependence on predictable fault current behaviour. Time-current based grading schemes are observed to be most susceptible, as they rely directly on fault current magnitude and consistent current distribution, both of which are increasingly variable in inverter-dominated systems. Directional overcurrent protection follows, where reduced and distorted fault contributions can compromise both sensitivity and directional discrimination. Distance protection, while less dependent on fault level, is increasingly challenged by variations in apparent impedance introduced by inverter control behaviour and weak infeed conditions. Even more robust schemes such as differential protection, while largely independent of system strength, remain constrained by communication requirements and practical deployment considerations.

Transpower's observation that backup Zone 2 protection may require fault current persistence for up to 1.5 seconds highlights a broader issue emerging from the transition to inverter-dominated power systems. It raises a potential incompatibility between conventional backup protection requirements and the fault-response capability of inverter-based resources. While the extent of this issue remains application dependent, it represents an area requiring further investigation to ensure conventional backup protection philosophies remain effective in highly inverter-dominated networks.

This progressive erosion of performance across conventional protection methods reflects a broader shift in system behaviour, where fault response is no longer governed primarily by network physics but is increasingly shaped by inverter control dynamics. This shift reflects a fundamental requirement to transition towards control system dynamics, rather than reliance on traditional protection principles founded on predictable, physics-driven fault current behaviour.

The findings identify several areas where further work is required, including the development of standardised performance requirements for inverter fault response, improved model transparency, and validation of emerging protection methods through EMT-level simulation and HIL testing. Regulatory and standards frameworks, including the NER and AS/NZS 4777, will play a critical role in providing the structure needed to support this transition.

Closing Statement

The primary conclusion of this study is not that a fundamentally new protection paradigm has already been realised, but that the industry is actively and pragmatically adapting to changing system conditions using a combination of established methods and emerging techniques. The challenge ahead lies in consolidating these developments into coherent, validated, and standardised approaches that can be deployed at scale across the Australian power system.

The transition to an inverter-dominated grid does not eliminate the need for protection; rather, it requires protection systems to evolve from purely measurement-based decision-making toward integrated, behaviour-aware frameworks supported by both improved device performance and advanced analytical methods.

14. Abbreviations and Definitions

Terms defined in the NER have the same meanings when used in this document, regardless of whether they are italicised or not. The meaning of other terms and abbreviations are given in Table 1.

Table 1 – List of Abbreviations and Definitions

Term	Definition or Expanded Term
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AFC	Available Fault Current
ARENA	Australian Renewable Energy Agency
AR-PST	Australian research in power systems transition
AS/NZS	Australian / New Zealand Standard
BESS	Battery Energy Storage Systems
CCT	Critical Clearing Time
CDU	Charles Darwin University
CER	Consumer Energy Resources
CHB	Cascaded H-Bridge
CIL	Controller-in-the-Loop
CIGRE	International Council on Large Electric Systems
CIRED	International Conference on Electricity Distribution
COMTRADE	Common Format for Transient Data Exchange
CREPS	Centre for Renewable Energy and Power Systems
CRS	Current Reference Saturation
CSC	Current-Source Control
CSIP-AUS	Common Smart Inverter Profile - Australia
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DC	Direct Current
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DFIG	Doubly-Fed Induction Generator
DL	Deep Learning
DOE	Dynamic Operating Envelope
dq	Direct-quadrature reference frame
DSC	Decoupled Sequence Control
DSSI	Distribution System Strength Index
DSV	Distributed Secondary Voltage
DTEF	Directional Transient Earth Fault

Term	Definition or Expanded Term
EOL	End of Life
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESO	Electricity System Operator
ESR	Equivalent series resistance
ESS	Essential System Services
EMT	Electromagnetic Transient
FCAS	Frequency control ancillary service
FCS	Frequency Control Strength
FFR	Fast frequency response
FFT	Fast Fourier Transform
FRT	Fault Ride-Through
GFL	Grid-following
GFM	Grid-forming
GFM-BESS	Grid-forming Battery Energy Storage System
GIST	Grid Impedance Scan Tool
GNC	Generalised Nyquist Criterion
GOOSE	Generic Object-Oriented Substation Event (IEC 61850)
GPS	Generator Performance Standards
GSI	Grid Strengthening IBR
GSKO	Gaining - Sharing Knowledge Optimization
HIL	Hardware-in-the-Loop
HILP	High-Impact, Low-Probability
HVDC	High voltage direct current
Hz	Hertz
IBR	Inverter-Based Resource
IDMT	Inverse Definite Minimum Time
IED	Intelligent Electronic Device
IGE	Induction Generator Effect
IIDG	Inverter-Interfaced Distributed Generation
ISP	Integrated System Plan
kV	Kilovolt
LV	Low Voltage
MAS	Multi-Agent Systems
MASS	Market Ancillary Service Specification
MEI	Melbourne Energy Institute
ML	Machine Learning
ms	Milliseconds
MVA	Mega Volt-Ampere

Term	Definition or Expanded Term
MW	Megawatt
MHz	Mega Hertz
NEM	National Electricity Market
NER	National Electricity Rules
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
NSP	Network Service Provider
OAFC	Online Adaptive Frequency Control
OCPP	Open Charge Point Protocol
OEM	Original Equipment Manufacturers
OPAL-RT	Trusted Real-Time Simulation Solutions
PCC	Point of Common Coupling
PCS	Power Conversion System
PES	Power and Energy Society (IEEE)
PFC	Primary Frequency Control
PI	Proportional-Integral Controller
PICD	PLL Internal Coherence Deviation
PLL	Phase-Locked Loop
PMU	Phasor Measurement Unit
PNNL	Pacific Northwest National Laboratory
POC	Point of Connection
POD	Power Oscillation Damping
PSCAD	Power Systems Computer Aided Design (EMT simulation software)
PSRC	Power System Relaying and Control Committee (IEEE)
pu	Per Unit
PV	Photovoltaic
PWC	Power and Water Corporation
RES	Renewable Energy Sources
REZ	Renewable Energy Zone
RMS	Root Mean Square
RoA	Region of Attraction
RoCoF	Rate-of-Change-of-Frequency
RTDS	Real-Time Digital Simulation
SCR	Short-Circuit Ratios
SEL	Schweitzer Engineering Laboratories
SIR	Source Impedance Ratio
SoC	State-of-Charge
SOGI	Second Order Generalised Integrator
SSO	Sub-Synchronous Oscillations

Term	Definition or Expanded Term
SSR	Sub-Synchronous Resonance
STATCOM	Static Compensator
SVM	Support Vector Machines
SWAMS	Subsynchronous Wide-Area Monitoring Systems
SWER	Single Wire Earth Return
SWIS	South West Interconnected System
SynCon	Synchronous Condenser
TI	Torsional Interaction
TNSP	Transmission Network Service Provider
TPSS	Transition Plan for System Security
TSO	Transmission System Operator
TW	Travelling-wave
UFLS	Under-Frequency Load Shedding
UNIFI	Universal Interoperability for Grid-forming Inverters
UoM	University of Melbourne
UTAS	University of Tasmani
UQ	University of Queensland
V2G	Vehicle-to-Grid
VCO	Voltage Controlled Oscillator
VFFR	Very Fast Frequency Response
VPP	Virtual Power Plant
VPR	Voltage-Priority Reference
VSC	Voltage Source Converters
VSG	Virtual Synchronous Generator
VSM	Virtual Synchronous Machine
WMZ	West Murray Zone
XRIO	Extensible Relay Input/Output (relay setting data exchange format)

15. Bibliography

[1] Etik Energy, “Grid-Forming and Grid-Following Inverter Fault Current Contribution,” *Public Release V 2.1,* November 2025.

[2] J. H. a. A. O. R. Heydari, “Stability Enhancement of Weak Grids with High Penetration of Renewables with Grid Forming STATCOM/Enhanced-STATCOM, Hitachi Review,” May 2025.

[3] CIGRE Working Group B5.48, “Protection for Developing Network with Limited Fault Current Capability of Generation,” *Technical Brochure 896,* April 2023.

[4] CIGRE Joint Working Group C4/B4, “Guidelines for Subsynchronous Oscillation Studies in Power Electronics Dominated Power Systems,” Technical Brochure 909, October 2023.

[5] J. H. H. Y. S. S. &. T. H. Liu, “ Virtual power plant with renewable energy sources and energy storage systems for sustainable power grid-formation, control techniques and demand response,” *Energies,* vol. 16(9), no. 3705, 2023.

[6] J. e. a. Bialek, “System Strength and Weak Grids: Fundamentals, Challenges, and Mitigation Strategies,” *IEEE Transactions on Power Systems,* 2021.

[7] AEMO, “2024 Integrated System Plan”.

[8] AEMO, “NEM Virtual Power Plant (VPP) Demonstrations Program,” 2019.

[9] AEMO, “NEM Virtual Power Plant (VPP) Demonstrations Program”.

[10] AEMO, “2025 Transition Plan for System Security,” December 2025. [Online]. Available: https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-transition-plan-for-system-security.pdf?rev=0984b6183240456bbc85bfaaa12fec62&sc_lang=en.

[11] AEMO, “2025 Inputs, Assumptions and Scenarios Report,” August 2025. [Online]. Available: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2024/2025-iasr-scenarios/final-docs/2025-inputs-assumptions-and-scenarios-report.pdf?rev=63268acd3f044adb9f5f3a32b6880c27&sc_lang=en.

[12] CSIP-AUS, “Common Smart Inverter Protocol - Australia,” [Online]. Available: https://www.csipaus.org/.

[13] AEMO, “Distributed PV An overview of the RIS Technical Appendix A,” [Online]. Available: https://www.aemo.com.au/-/media/files/major-publications/ris/2020/webinar_ris_dpv.pdf?la=en.

[14] IEEE, “Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces,,” *IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003),* 2018.

[15] AS/NZS 4777, “Grid connection of energy systems via inverters, Part 1: Installation requirements.,” 2024.

[16] AS/NZS 4777, “Grid connection of energy systems via inverters, Part 2 Inverter Requirements,” 2020.

[17] next, “The Power of Many,” [Online]. Available: https://www.next-kraftwerke.com/vpp.

[18] solar choice, “Sonnen VPP (sonnenConnect) – Independent Review,” [Online]. Available: https://www.solarchoice.net.au/solar-batteries/vpp/sonnen/.

[19] Statkraft, “Virtual Power Plants,” [Online]. Available: https://www.statkraft.com/what-we-offer/energy-flexibility-management/virtual-power-plants/.

[20] Aurecon, “Advice on the maturity of grid forming inverter solutions for system strength,” Aurecon, Melbourne, 2024.

[21] CIGRE, “Comparision Between Synchronous Condensers and Grid Forming BESS in Providing System Strength Support to IBRs in Weak and Strong Power Systems Using EMT Simulation,” in *SC C4 - Power system Technical Performance*, Norway, 2025.

[22] Sandia Laboratories, “Impact of Inverter Based Resource Negative Sequence Current Injection on Transmission System Protection,,” *SAND2020-0265,* January 2020.

[23] CIGRE, “Riverstone STATCOM: Grid Forming Controls for a Robust Solutoins Under Changing System Conditions,” in *B4 DC Systems and Power Electronics* , Quebec, 2025.

[24] Hitachi, “Stability Enhancement of Weak Grids with High Penetration of Renewables withGrid Forming STATCOM/Enhanced-STATCOM,” *Hitachi Review,* May 2025.

[25] R. e. a. Heydari, “Stability Enhancement in Weak Grids with High Renewable Penetration: Synchronous Condenser vs. Converter-based Technologies,” in *CIGRE 2025 International Symposium*, Montreal, 2025.

[26] CIGRE, “Power Oscillaton Damping Using Grid-forming HVDC Converters,” in *B4 DC Systems and Power Electronics*, Quebec, 2025.

[27] CIGRE, “Assessment of Grid Forming capabilities of HVDC links with analytical envelopes - Application to HVDC link with grid forming on both sides,” in *SC B4 - DC Systems and power electronics* , Quebec, 2025.

[28] CIGRE, “HVDC and STATCOMs, Not Your Typical IBRs,” in *B4 DC Systems & Power Electronics*, Quebec, 2025.

[29] CIGRE, “A new STATCOM topology equipped with short-time energy storage and Grid,” in *B4 DC Systems and Power Electronics*, Quebec, 2025.

[30] R. M. R. &. F. N. Chowdhury, "Line Current Differential Protection in Systems With Inverter-Based Resources — Challenges and Solutions," SEL, 2022–2024.

[31] R. C. a. N. Fischer, “Transmission Line Protection for Systems With Inverter-Based Resources—Part I: Problems,” in *IEEE Transactions on Power Delivery, vol. 36, no. 4, pp. 2416-2425, doi: 10.1109/TPWRD.2020.3019990*, Aug. 2021.

[32] North American Electric Reliability Corporation (NERC), “Inverter-Based Resource Performance Issues Report,” [Online]. Available: https://www.nerc.com/globalassets/our-work/reports/white-papers/nerc_inverter-based_resource_performance, Atlanta, GA, USA, Nov. 15, 2023.

[33] J. X. a. T. E. M. X. Lyu, “Impact of Inverter-Based Resources on Grid Protection: A Review of Negative-Sequence Current Generation,” Pacific Northwest National Lab. (PNNL), Tech. Rep. PNNL-36069, [Online]. Available: https://www.osti.gov/biblio/2377006 , Richland, WA, USA, Jun. 2024.

[34] M. J. R. a. E. F. U. Muenz, “Protection of 100% Inverter-Dominated Power Systems with Grid-Forming Inverters and Protection Relays – Gap Analysis and Expert Interviews,” Sandia National Laboratories, Tech. Rep. SAND2024-04848, Albuquerque, NM, USA, Apr. 2024.

[35] IEEE Power System Relaying and Control Committee, “Protection Challenges and Practices for Interconnecting Inverter-Based Resources to Utility Transmission Systems,” Power & Energy

Society, Tech. Rep. PES-TR81, Jul. 2020. [Online]. Available: https://resourcecenter.ieee-pes.org/publications/technical-reports/pes_tp_tr81_psrc_wgc32_071520, Piscataway, NJ, Jul. 2020.

[36] J. P. A. A. M. S. a. S. G. S. V. Telukunta, “Protection challenges under bulk penetration of renewable energy resources in power systems: A review,” CSEE Journal of Power and Energy Systems, vol. 3, no. 4, pp. 365–379, doi: 10.17775/CSEEJPES.2017.00030, Dec. 2017.

[37] M. Z. S. A. G. A. M. S. S. D. M. Z. E. T. S. a. E. R. J. S. Farkhani, “The Power System and Microgrid Protection—A Review,” Applied Sciences, vol. 10, no. 22, p. 8271, doi: 10.3390/app10228271, Nov. 2020.

[38] Electric Power Research Institute (EPRI), “Impact of Inverter-Based Resources on Protection Schemes Based on Negative Sequence Components,” Technical Brief — Bulk Power System Integration of Variable Generation, Palo Alto, CA, 2019.

[39] S. A.-R. A. &. F. F. Chowdhury, “Adaptive protection strategies for inverter-rich networks,” IEEE Transactions on Power Delivery, vol. 36, no. 4, pp. 2200–2212, Aug. 2021.

[40] Electric Power Research Institute (EPRI), “Impact of Inverter-Based Resources on Protection Schemes Based on Negative Sequence Components,” White Paper 3002016197. [Online]. Available: https://www.epri.com/research/products/000000003002016197, Palo Alto, CA, USA, Jul. 2019.

[41] K. P. A. S. a. P. K. S. Y. N. Velaga, “Y. N. Velaga, K. Prabakar, A. Singh, and P. K. Sen, "Traveling Wave Relays for Distribution Feeder Protection with High Penetrations of Distributed Energy Resources,",” in Proc. 2021 IEEE Rural Electric Power Conference (REPC), pp. 1-6. [Online]. Available: https://docs.nrel.gov/docs/fy21osti/79741.pdf, Golden, CO., 2021.

[42] M. L. M. H. K. a. A. M.-S. M. Beikbabaei, “Machine Learning-Based Protection and Fault Identification of 100% Inverter-Based Microgrids,” arXiv preprint arXiv:2405.07310, [Online]. Available: https://arxiv.org/abs/2405, May 2024.

[43] X. D. A. &. B. G. Li, “Traveling wave-based protection scheme for inverter-dominated microgrid using mathematical morphology,” IEEE Transactions on Smart Grid, vol. 5, no. 5, pp. 2211-2218, DOI: 10.1109/TSG.2014.2320365 , Sept. 2014.

[44] F. L. Y. &. B. M. Ventura, “Traveling-wave and data-driven protection for IBR-rich networks,” IEEE Transactions on Power Delivery, vol. 37, no. 2, pp. 1254–1265, Apr. 2022.

[45] S. P. a. A. S. M. Ferraro, “Characterisation of Sequence Components for a Standalone Microgrid with Low Fault Current,” Paper no. 10550, in 27th International Conference on Electricity Distribution (CIRED), Rome, Italy, 12–15 Jun. 2023..

[46] Schweitzer Engineering Laboratories (SEL), “Performance evaluation of overcurrent protection in low fault-current networks,” SEL Technical Report,, 2020.

[47] E. P. R. I. (EPRI), “Protection coordination in weak grids with high inverter penetration,” EPRI Report 3002023856, 2021.

[48] N. R. E. L. (NREL), “Relay performance in inverter-dominated networks,” NREL Technical Report TP-5D00-81392, 2020.

[49] E. F. I. K. a. U. K. A. Haddadi, “Impact of Inverter Based Resources on System Protection,” Energies, vol. 14, no. 4, p. 1050, doi: 10.3390/en14041050, Feb. 2021.

[50] R. C. a. N. Fischer, “Transmission Line Protection for Systems With Inverter-Based Resources—Part II: Solutions,” IEEE Transactions on Power Delivery, vol. 36, no. 4, pp. 2426-2433, doi: 10.1109/TPWRD.2020.3030168, Aug. 2021.

[51] E. P. R. I. (EPRI), “Impact of Inverter-Based Resource Negative-Sequence Components on Protection Schemes,” Tech. Rep. 3002016197, [Online]. Available: EPRI Product Page , Palo Alto, CA, USA, Jul. 2019.

[52] D. M. a. N. F. B. Kasztenny, “Power-Swing Detection Logic for Systems With Low Inertia,” Schweitzer Engineering Laboratories, Inc.,Tech. Paper 7142, 2023, Pullman, WA, USA.

[53] CIGRE, “Reimagining System Protection for a Grid Dominated by Inverter-Based Resources,” *ELECTRA CIGRE's Digital Magazine,* 2026.

[54] E. F. I. K. a. U. K. A. Haddadi, “Impact of Inverter Based Resources on System Protection, doi: 10.3390/en14041050,” *Energies,* Vols. vol. 14, no. 4, p. p. 1050, Feb. 2021.

[55] A. A. A. e. al, “Fault Ride Through of Inverter-Interfaced Renewable Energy Sources for Enhanced Resiliency and Grid Code Compliance,” *IEEE Transactions on Sustainable Energy, doi: 10.1109/TSTE.2022.31831,* vol. vol. 13, no. no. 4, pp. pp. 2096-2108, Oct. 2022.

[56] F. B. a. P. M. J. S. H. Lee, “A review of system strength and inertia requirements and mitigation strategies in renewable-energy-dominated grids,” CSEE Journal of Power and Energy Systems, vol. 11, no. 1, 2025.

[57] F. B. a. J. S. H. L. P. Mancarella, “System strength beyond fault level: A multi-dimensional stability framework for inverter-based resources,” IEEE Transactions on Power Systems, vol. 39, no. 2, pp. 1450–1465, Mar. 2024.

[58] F. B. a. J. S. H. L. P. Mancarella, “System strength beyond fault level: A multi-dimensional stability framework for inverter-based resources,” IEEE Transactions on Power Systems, vol. 39, no. 2, pp. 1450–1465, Mar. 2024.

[59] University of Melbourne, “Reactive Technologies System Inertia Measurement Demonstration Project: Final Technical Knowledge Sharing Report,” Melbourne Energy Institute for ARENA/AEMO, Sep. 2024.

[60] M. H. R. a. B. Bahrani, “Transient stability analysis of grid-forming inverters with current limits,” EEE Transactions on Power Systems, vol. 38, no. 1, 2023.

[61] H. W. a. B. Bahrani, “Grid-forming inverters: A comparative study of different control strategies,” IEEE Access, 2024.

[62] B. B. e. al., “Stage 4 Research Report: Large signal stability enhancement in IBR-dominated grids,” CSIRO AR-PST Technical Report, Aug. 2025.

[63] M. U. Team, “Advanced inverter applications for current-limited grid-forming inverters,” AR-PST Stage 3 Final Report, 2024.

[64] M. E. Institute, “Stability Enhancing Measures for Weak Grids Study,” ARENA Project Report, Mar. 2024.

[65] G. R. (ed.), “On The Grid: Australian Electricity in Transition,” Monash University Publishing, 1st ed., 2022.

[66] T. K. S. a. B. B. M. R. Alam, “Australia's Power System Frequency: Current Situation and Future Research Directions,” IEEE Open Access Journal of Power and Energy, vol. 10, (Joint with UQ), 2023.

[67] J. L. a. T. K. Saha, “Black-Start Strategies for Microgrids with High Penetration of Inverter-Based Resources, IEEE Transactions on Smart Grid, vol. 13, no. 1, pp. 445–458.,” Jan. 2022.

[68] T. K. S. a. R. Y. S. Cui, “Probabilistic Voltage Stability Assessment of Power Systems With High Wind Power Penetration, IEEE Transactions on Sustainable Energy, vol. 11, no. 4, pp. 2401–2411.,” Oct. 2020.

[69] T. K. S. a. R. Y. X. Wu, “Aggregate Modelling of Distributed Energy Resources for Large-Scale Power System Dynamic Studies, IEEE Transactions on Power Systems, vol. 38, no. 4, pp. 3201–3214.,” July 2023.

[70] R. Y. a. T. K. S. H. Gu, “Review of system strength and inertia requirements for the national electricity market of Australia,” CSEE Journal of Power and Energy Systems, vol. 8, no. 1, pp. 11–21, Jan. 2022.

[71] T. K. S. a. F. B. R. Yan, “Data-Driven Model Identification of Variable Renewable Generation for Power System Stability Studies, IEEE Transactions on Power Systems, vol. 36, no. 2, pp. 1244–1255.,” Mar. 2021.

[72] R. Y. a. T. K. S. F. Bai, “A Measurement-Based Strategy for Real-time Inertia Estimation in Inverter-Dominated Power Systems, IEEE Transactions on Power Systems, vol. 37, no. 3, pp. 1956–1967.,” May 2022.

[73] X. W. a. M. Z. H. Wu, “Fault Current Contribution and Control of Inverter-Based Resources in Weak Grids, IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 10, no. 2, pp. 1542–1555.,” Apr. 2022.

[74] M. N. E. F. a. S. L. M. R. Amin, “Application of Battery Energy Storage Systems for Primary Frequency Control in Power Systems with High Renewable Energy Penetration,” Energies, vol. 14, no. 5, p. 1379, Mar. 2021.

[75] M. N. a. E. F. M. R. Amin, “Battery Energy Storage Systems: Energy Market Review, Challenges and Opportunities in Frequency Control Ancillary Services,” Energies, vol. 18, no. 15, p. 4174, Aug. 2025.

[76] M. N. a. E. F. W. Hassan, “A State-of-Charge-Frequency Control Strategy for Grid-Forming Inverters with BESS,” Batteries, vol. 11, no. 8, p. 296, Aug. 2025.

[77] E. F. a. W. H. M. Negnevitsky, “Enhancing Grid Stability and Resilience through BESS Optimal Deployment,” Energy Reports, vol. 13, pp. 1764-1775, Jun. 2025.

[78] M. R. A. a. M. Negnevitsky, “Enhancing Frequency Response Characteristics of Low Inertia Power Systems Using Battery Energy Storage,” ResearchGate, Technical Report, Aug. 2024.

[79] P. A. H. a. M. Negnevitsky, “A Comprehensive Approach to Evaluate Frequency Control Strength of Power Systems,” ResearchGate, Oct. 2024.

[80] M. R. Amin, “Power system frequency control using battery energy storage systems,” Ph.D. dissertation, School of Engineering, Univ. of Tasmania, Hobart, Australia, 2024.

[81] M. N. a. E. F. A. Eslami, “Fast Extraction of Distorted Portion of Non-Stationary Signals Using a Dynamic Adalin,” In Proc. 2025 IEEE Power & Energy Society General Meeting (PESGM), pp. 1-5, Jul. 2025.

[82] E. M. G. J. L. a. M. N. M. A. Hossain, “Optimized Model-Free Frequency Control for Renewable Energy Integration in Islanded Power Systems,” IEEE Trans. Ind. Appl., vol. 62, no. 2, pp. 2084–2096, Mar. 2025.

[83] S. B. e. al., “Incentive Mechanisms for Smart Grid: State of the Art, Challenges, Open Issues, Future Directions,” Big Data Cogn. Comput., vol. 6, no. 2, Art. 47, Jun. 2022.

[84] M. A. H. a. S. Thennadil, “Stability Improvement of Microgrids under Dynamic Load and Renewable Generation Variations,” Proc. IEEE Power & Energy Soc. Conf., Feb. 2026.

[85] S. T. a. M. A. Hossain, “Adaptive Control Strategies for Grid-Forming Inverters in Weak-Grid Environments,” IEEE Trans. Smart Grid (submitted/forthcoming), 2025.

[86] M. A. H. a. S. T. J. Lu, “Hardware-in-the-Loop Validation of Protection Schemes for Inverter-Dominated Microgrids,” Proc. Australasian Universities Power Engineering Conf. (AUPEC), Nov. 2024.

[87] T. R. S. a. S. Thennadil, “Distributed Secondary Control for Inverter-based Islanded Microgrids: Frequency and Voltage Synchronization,” CDU Student Theses, Oct. 2024.

[88] Renewable Energy Laboratory, “UNIFI Specifications for Grid Forming Inverter Based Resources: Version 2,” *NREL/TP 5D00 89269, National Renewable Energy Laboratory, Golden, CO,* March 2024.

[89] J. Wang and B. Johnson, “How Inverter Based Resources (IBRs) Affect Protection Relay Elements,” *NREL/PR 5D00 93804, Presented at ESIG Webinar Series,* 26 March 2025.

[90] K. P. e. al, “Use of Traveling Wave Signatures in Medium Voltage Distribution Systems for Fault Detection and Location,” *NREL/TP 5D00 78057, National Renewable Energy Laboratory, Golden, CO,* August 2021.

[91] N. K. Prabakar, “Stakeholder interview conducted by Amplitude Consultants for CSIRO PAU0503,” 9 December 2025.

[92] "Schweitzer Engineering Laboratories, "Field Experience With Traveling Wave Protection and Fault Locating," SEL Technical Publication, 2020".

[93] "RTDS Technologies, "Case Study: SEL T400L and T401L Travelling Wave Relay Testing," 2021.".

[94] National Grid ESO, "Stability Pathfinder Phase 2: Tender Results," April 2022.

[95] S. B. Reynolds, "What to Expect from Grid Forming Inverters," *Energy Systems Integration Group,* September 2023.

[96] North American Electric Reliability Corp., "ntegrating Inverter-Based Resources into Low Short Circuit Strength Systems," Atlanta, GA, USA, Dec. 2017.

[97] Electric Power Research Institute (EPRI), "Guidelines for Studies on Weak Grids with Inverter-Based Resources," EPRI Technical Update 3002013639, 2018.

[98] M. L. L. E. M. Uzair, "Challenges, Advances and Future Trends in AC Microgrid Protection: With a Focus on Intelligent Learning Methods," Renewable and Sustainable Energy Reviews, 178, 113228, 2023.

[99] T. B. S. H.-A. J. &. R. M. J. Patel, "Adaptive Protection Scheme for a Real-World Microgrid with 100% Inverter-Based Resources," Proceedings of the IEEE Kansas Power & Energy Conference (KPEC), Manhattan, KS, USA, 2020.

[100] A. M. R. F. G. A. L. A. T. D. S. &. O. C. Srivastava, "A Review on Challenges and Solutions in Microgrid Protection," IEEE PowerTech 2021 – Conference Proceedings. DOI: 10.1109/PowerTech46648.2021.9495090, 2021.

[101] A. C. R. A. D. O. D. &. F. P. Adewole, "Centralized Protection of Networked Microgrids with Multi-Technology DERs," Energies, vol. 16, no. 20, p. 7080, 2023. DOI: 10.3390/en16207080, 2023.

[102] M. L. M. K. M. H. &. M.-S. A. Beikbabaei, "Machine Learning-Based Protection and Fault Identification of 100% Inverter-Based Microgrids," arXiv preprint arXiv:2405.07310, May 2024.

[103] . T. &. P. Ferrari, "Grid Forming Inverter With Increased Short Circuit Contribution to Address Inverter Based Microgrid Protection Challenges," IEEE Open Journal of the Industrial Electronics Society, vol. 5, pp. 481 500.

[104] J. X. a. T. E. M. X. Lyu, "Impact of Inverter-Based Resources on Grid Protection: A Review of Negative-Sequence Current Generation," Pacific Northwest National Laboratory, Richland, WA, Tech. Rep. PNNL-36069, Jun. 2024.

[105] H. T. N. Y. W. O. A. M. a. E. A. T. L. Nguyen, "Distributed Secondary Control in Microgrids Using Synchronous Condenser for Voltage and Frequency Support," Energies, vol. 15, no. 8, p. 2968, 2022, doi: 10.3390/en15082968.

[106] W. T. E.-S. a. M. H. Sati, "Protection Coordination for Inverter-Based Microgrids Using Adaptive Directional Overcurrent Relays," Electric Power Systems Research, vol. 189, p. 106778, doi: 10.1016/j.epsr.2020.106778, Dec. 2020.

[107] M. A. A. H. H. Z. a. E. F. E.-S. W. T. El-Sayed, "A Harmonic Time–Current–Voltage Directional Relay for Optimal Protection Coordination of Inverter-Based Islanded Microgrids," IEEE Transactions on Smart Grid, vol. 12, no. 3, pp. 1904–1917, doi: 10.1109/TSG.2020.3044350, May 2021.

[108] T. E. A. M. A. &. S. M. F. Sati, "Adaptive Harmonic-Based Protection Coordination for Inverter-Dominated Microgrids considering N-1 contingency," International Journal of Electrical Power & Energy Systems, 156, 109750, 2024.

[109] M. A. A. a. E. F. E.-S. A. Hooshyar, "Distance Protection of Lines Emanating From Full-Scale Converter-Interfaced Renewable Energy Power Plants—Part I: Problem Statement," IEEE Transactions on Power Delivery, vol. 30, no. 4, pp. 1770-1780, doi: 10.1109/TPWRD.2014.2365854, Aug. 2015.

[110] Y. X. W. Y. a. J. W. H. Niu, "Communication-Assisted Protection Scheme for Microgrids With Inverter-Interfaced Distributed Generators," IEEE Transactions on Smart Grid, 2018.

[111] J. S. a. T. S. Sidhu, "A New Protection Scheme for Feeders of Microgrids with Inverter-Based Generation," presented at the IEEE Power & Energy Society General Meeting, 2023.

[112] M. L. L. E. M. Uzair, "Machine Learning Based Protection Scheme for Low Voltage AC Microgrids," IEEE Transactions on Smart Grid, 15(24), 9397, 2022.

[113] A. M. M. a. S. A. M. Ali, "Intelligent Protection Strategies for Inverter-Based Microgrids: A Review," Renewable and Sustainable Energy Reviews, vol. 150, p. 111495, doi: 10.1016/j.rser.2021.111495, 2021.

[114] AEMC, "Enhancing the NER frameworks to define acceptable limits of sub-synchronous power system oscillations in the NEM.".

[115] AEMO, "2025 Transition Plan for System Security," December 2025. Available: https://www.aemo.com.au/-/media/files/major-publications/tpss/2025-transition-plan-for-system-security.pdf.

[116] AEMO, "Analysis of Sub-synchronous Oscillations in West Murray Zone Power System in Australia," July 2025. Available: https://www.aemo.com.au/-/media/files/initiatives/engineering-framework/2025/analysis-of-sub-synchronous-oscillation-in-west-murray-zone-.

[117] NREL and AEMO, "Analysis of Oscillations in AEMO's West Murray Zone," NREL/TP-5D00-88448, ESIG 2024 Spring Technical Workshop. Available: https://docs.nrel.gov/docs/fy24osti/88448.pdf.

[118] "Y. Cheng et al., "Real-World Subsynchronous Oscillation Events in Power Grids with High Penetrations of Inverter-Based Resources," IEEE Trans. Power Syst., 2022.".

[119] "National Electricity Rules, Clause S5.2.5.10, "Detection and response to unstable operation."".

[120] in *https://www.aemo.com.au/consultations/current-and-closed-consultations/ner-s52510-guideline-consultation*.

[121] NREL and AEMO, "Analysis of Oscillations in Australian Energy Market Operator's West Murray Zone,," Energy Systems Integration Group 2024 Spring Technical Workshop, 2024. [Online]. Available: https://www.nrel.gov/grid/impedance-measurement#:~:text=Analysis%20of%20Oscillations%20in%20Australian%20Energy%20Market%20Operator%27s%20West%20Murray%20Zone%2C.

[122] "AEMO, "Inverter-based resource controller design using frequency scanning techniques," November 2025. Available: https://www.aemo.com.au/-/media/files/initiatives/frequency-scanning/inverter-based-resource-controller-design-using-frequency-scanning-techni".

[123] "S. Shah et al., "Grid Impedance Scan Tool (GIST): Software for Stability Analysis of IBR Power Systems," EPRI SSO Workshop, April 2023. Available: https://research-hub.nrel.gov/en/publications/grid-impedance-scan-tool-gist-software-for-stability-analysis-".

[124] "U.S. DOE / NREL, Impedance Measurement programme and "Testing Tool Ensures Renewables and the Grid Are In Tune." Available: https://www.nrel.gov/grid/impedance-measurement".

[125] AEMO, "Power System Analysis Tools – Future Requirements independent review," 2024. [Online]. Available: https://www.aemo.com.au/energy-systems/electricity/national-electricity-

market-nem/participate-in-the-market/network-connections/power-system-analysis-tools. [Accessed 31 11 2025].

[126] "AEMO, "Frequency scanning" Focus Areas and Initiatives. Available: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/participate-in-the-market/network-connections/connection-resources/focus-areas-and-initiatives/frequency-".

[127] "AEMO, "Improving grid stability through frequency scanning," July 2025. Available: https://www.aemo.com.au/-/media/files/initiatives/frequency-scanning/improving-grid-stability-through-frequency-scanning---july-2025.pdf".

[128] "M. Sahni et al., "Sub-synchronous interaction in wind power plants – Part II: An ERCOT case study," IEEE PES General Meeting, 2012.".

[129] "ERCOT, "SSO Screening and Detailed Studies," IBR Working Group, October 2024. Available: https://www.ercot.com/files/docs/2024/10/15/Sub-Synchronous%20Control%20Instability%20Studies%20ERCOT%20Oct%2011%202024_Rev02.pdf".

[130] "IEEE PES IBR SSO Task Force, various publications 2017–2024. Available: https://sites.google.com/view/windsso/home".

[131] "X. Xie et al., "Wide-area monitoring and early-warning of subsynchronous oscillation in power systems with high-penetration of renewables," Int. J. Electrical Power & Energy Systems, vol. 108, pp. 31–39, 2019".

[132] "X. Xie et al., "Wide-area monitoring and early-warning of subsynchronous oscillation in power systems with high-penetration of renewables," Int. J. Electrical Power & Energy Systems, vol. 108, pp. 31–39, 2019".

[133] "L. Wang, X. Xie et al., "Review of emerging SSR/SSO issues and their classifications," Journal of Engineering, 2017".

[134] CIGRE, "TB398 - Third-Party Damage to Underground and Submarine Cables," CIGRE, 2009.

[135] British Columbia Transmission Corporation, "Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project," 2005.

[136] Berdal Stromme, “Norned Kabel HVDC Project RAM Study Phase 2,” 1998.

[137] MANITOBA HVDC RESEARCH CENTRE, a Division of Manitoba Hydro International Ltd., “Sub Synchronous Oscillations – An Introduction,” October 2016.

[138] AEMO, “NER S5.2.5.10 - Asynchronous generatong ujits and dynamic reactive plant,” S5.2.5.10 Initial Summary Guide, 2022. [Online]. Available: https://www.aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2022/ner-s52510/s52510-initial-summary-guide.pdf?la=en. [Accessed 28 October 2025].

[139] Powerlink, “Inverter Based Reneable Plant: GPS Connection Study Process and Expectations,” January 2024.

[140] N. Shahil Shah, “Grid Impedance Scan Tool (GIST),” Subsynchronous Oscillations Workshop, EPRI, 2023. [Online]. Available: https://docs.nrel.gov/docs/fy23osti/86112.pdf.

[141] “National Electricity Rules Version 200”.

[142] Government of South Australia, “South Australia's Virtual Power Plant,” [Online]. Available: https://www.energymining.sa.gov.au/consumers/solar-and-batteries/south-australias-virtual-power-plant.

[143] M. .. e. a. Khan, “Grid-forming control for inverter-based resources in power systems: A review. IET Renewable Power Generation.,” 2024.

[144] J. C. T. E. L. D. M. &. P.-M. M. J.] Sarmiento-Vintimilla, “Applications, operational architectures and development of virtual power plants as a strategy to facilitate the integration of distributed energy resources,” *Energies,* vol. 15(3), p. 775, 2022.

[145] Dlean Energy Regulator, “Virtual power plants,” [Online]. Available: https://cer.gov.au/schemes/renewable-energy-target/small-scale-renewable-energy-scheme/small-scale-renewable-energy-systems/solar-batteries/virtual-power-plants#vpp-capability-.

[146] L. &. M. Z. (. Fan, “Stability Analysis of Two Types of Grid-Forming Converters for Weak Grids,” *IEEE Transactions on Power Systems,* 2021.

[147] M. G. e. a. Ippolito, “Comparative assessment of typical control realizations of grid forming converters based on their voltage source behaviour,” *Electric Power Systems Research,* 2022.

[148] B. e. a. Zhou, “Virtual synchronous machine-based controller for multiple fast charging stations in grid stability support,” *Energy Conversion and Management,* 2025.

[149] IEEE 2800, “Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems,” 2022.

[150] GreyB, “Virtual Power Plant: A Growing Energy Storage Trend in 2025,” [Online]. Available: https://www.greyb.com/blog/virtual-power-plant-companies/.

[151] VP3, “Virtual Powert Plant Partnership,” [Online]. Available: https://vp3.io/.

[152] solar choice, “SimpliPhi Battery: An Independent Review by Solar Choice,” [Online]. Available: https://www.solarchoice.net.au/products/batteries/Simpliphi-battery-review/.

[153] J. L. N. M. Shahil Shah1, Analysis of Oscillations in AEMO’s West, AEMC, NREL, 2024.

[154] “NER - Protection to trip plant for unstable operation,” [Online]. Available: https://energy-rules.aemc.gov.au/ner/468/253926.

[155] CIGRE Study Committee B5, “V. Leitloff, "Network Protection in a changing system",” September 2025.

[156] ARENA/Ekistica, “Lessons Learnt and Future Directions from ARENA's Grid Forming Battery Portfolio, Findings Update Report,” October 2025.

[157] National Grid ESO, “Modern Power Systems,” *GB's First Grid Forming Battery Connected,* March 2025.

[158] Y. L. e. al., “Impact of Grid Forming Inverters on Protective Relays,” *University of Washington,* May 2025.

[159] N. J. e. al, “Impacts of Grid Forming Inverters on Distance Protection,” *Luleå University of Technology,,* January 2025.

[160] P. M. a. J. H. B. Y. Lin, “Grid-Forming Inverters for Black Start and Power System Restoration, IEEE Transactions on Power Systems,” 2023.

[161] S. K. A. a. P. Mancarella, “On the Stability and Control of Grid-Forming and Grid-Following Inverters in Weak Grids,” 2023.

[162] S. K. A. a. P. Mancarella, “Dynamics of Inverter-Based Resources in Weak Distribution Grids, IEEE Transactions on Power System.,” 2022.

[163] N. O. e. a. M. Z. Liu, “On the Role of Integrated MV–LV Network Modelling in DER Studies, IEEE Transactions on Power Systems, vol. 36, no. 1, pp. 583–593, doi: 10.1109/TPWRS.2020.3026368.,” Sept. 2020,.

[164] e. a. L. N. Ochoa, “Insights of Residential Smart Meter Data in Australia, IEEE Access, doi: 10.1109/ACCESS.2023.3332612.,” Nov. 2023.

[165] E. A. M.-C. a. P. Mancarella, “ntegrated Electricity and Gas Systems Modelling: Assessing the Impacts of Electrification of Residential Heating in Victoria, IEEE Transactions on Power Systems.,” 2020.

[166] M. S. S. A. a. P. Mancarella, “Small-Signal Stability Analysis of Inverter-Based Microgrids with Grid-Forming and Grid-Following Capabilities, in Proc. IEEE Madrid PowerTech, Madrid, Spain, 2021, pp. 1–6, doi: 10.1109/PowerTech47570.2021.9533721.,” 2021.

[167] H. W. P. D. F. B. a. B. B. M. G. Taul, “Current Reference Generation and Limits for Grid-Forming Inverters,IEEE Transactions on Power Electronics, vol. 36, no. 2, pp. 1455–1469.,” Feb. 2021.

[168] T. K. S. a. B. B. S. Alenany, “Small-Signal Stability Analysis of Grid-Forming Inverters in Weak Grids Considering the Effects of Phase-Locked Loops, IEEE Open Access Journal of Power and Energy, vol. 10, pp. 124–135, 2023.”.

[169] A. L. a. G. V. M. Z. Liu, “Optimal Dynamic Operating Envelopes for DERs in Low Voltage Grids, IEEE Transactions on Power Systems, vol. 38, no. 3, pp. 2456–2469.,” May 2023.

[170] S. R. D. a. S. M. M. N. Al-Masood, “A New Methodology for Estimating the Hosting Capacity of Distribution Networks Considering Voltage and Thermal Constraints, IEEE Access, vol. 9, pp. 156221–156233, 2021.”.

[171] S. A. a. B. B. S. Alibeiki, “Fault Current Analysis of Grid-Forming Inverters with Current Limiting Strategies, IEEE Transactions on Power Delivery, vol. 38, no. 5, pp. 3122–3135.,” Oct. 2023.

[172] S. M. M. a. M. G. S. M. Shafiullah, "Protection Challenges in Microgrids with High Inverter-Based Resource Penetration, IEEE Systems Journal, vol. 16, no. 3, pp. 3840–3851.," 2022.

[173] R. D. a. J. Percival, "The Role of Long-Duration Energy Storage in a Deeply Decarbonized Australian National Electricity Market," Energy, vol. 263, Part B, 125958.," Jan. 2023.

[174] R. D. a. A. L. T. Moore, "The Impact of Sector Coupling on the Integrated Energy System: A Case Study of Green Hydrogen in Australia, Applied Energy, vol. 310, 118556.," Mar. 2022.

[175] R. J. H. a. B. B. C. Bergmeir, "Short-term Forecasting of Solar PV Power Generation using Deep Learning and Smart Meter Data, Renewable Energy, vol. 182, pp. 1100–1115.," 2022.

[176] B. B. a. A. L. Y. Wang, "A Data-Driven Approach for Estimating the Short-Circuit Ratio in Weak Grids with High IBR Penetration, IEEE Transactions on Smart Grid, vol. 14, no. 4, pp. 2901–2914.," Jul. 2023.

[177] H. Z. a. T. K. Saha, "Evaluating the Performance of Distance Protection in the Presence of Inverter-Based Resources, IEEE Access, vol. 9, pp. 145000–145012.," 2021.

[178] T. M. a. R. Dargaville, "The Role of Hydrogen Electrolysers in Providing Ancillary Services to the Australian National Electricity Market, Applied Energy, vol. 310, 118556.," Mar. 2022.

[179] J. P. a. R. Dargaville, "Long-Duration Energy Storage Requirements for a 100% Renewable Australian NEM, Energy, vol. 263, 125958.," Jan. 2023.

[180] T. K. S. a. R. Y. L. Wang, "Operational Optimization of Multi-Energy Systems with High Penetration of Renewables, IEEE Transactions on Sustainable Energy, vol. 13, no. 4, pp. 2155–2167.," Oct. 2022.

[181] T. K. S. a. R. Y. S. K. Chaudhary, "Adaptive Protection Scheme for Microgrids with High Inverter-Based Resource Penetration, IEEE Transactions on Power Delivery, vol. 36, no. 4, pp.," Aug. 2021.

[182] T. K. S. a. R. Y. Y. Gu, "Coordinated Planning of Transmission Expansion and Renewable Energy Zones Considering System Strength, IEEE Transactions on Power Systems, vol. 37, no. 5, pp. 3855–3867.," Sept. 2022.

[183] T. K. S. a. R. Y. S. P. Adhikari, "Coordinated Control of Virtual Power Plants for Providing Frequency Support Services, IEEE Transactions on Sustainable Energy, vol. 12, no. 2, pp. 889–901.," Apr. 2021.

[184] M. Z. L. a. T. K. Saha., "Optimal Allocation of Dynamic Operating Envelopes for DERs in Unbalanced Distribution Networks, IEEE Transactions on Smart Grid, vol. 14, no. 2, pp. 1120–1132.," Mar. 2023.

[185] P. E. a. M. –. R. Energy, "Reimagining System Protection for a Grid Dominated by Inverter-Based Resources," *Electra Cigre Digital Magazine,* 2026.

[186] P. E. a. M. –. R. Energy, "Reimagining System Protection for a Grid Dominated by Inverter-Based Resources," *ELECTRA CIGRE's Magazine,* 2026.

[187] CIGRE, "PS1: System Enhancement, Markets and Regulation," in *C4 Power System Technical Performance*, Quebec, 2025.

[188] J. S. H. L. a. P. M. Y. J. Liu, "A novel voltage-priority reference generation strategy for IBRs to enhance PLL stability in weak grids," IEEE Journal of Emerging and Selected Topics in Power Electronics, vol. 10, no. 5, pp. 5821–5834, Oct. 2022.

[189] L. N. O. a. P. M. N. P. S. S. Rathnayake, "System strength in distribution grids: Concepts, metrics, and challenges for high DER penetration," IEEE Open Access Journal of Power and Energy, vol. 9, pp. 412–425, Oct. 2022.

[190] J. S. H. L. a. P. M. M. R. Alam, "Techno-economic assessment of real-time inertia measurements and forecasting for the Australian National Electricity Market," IEEE Power & Energy Soc. Gen. Meet. (PESGM), pp. 1, Orlando, FL, USA, 2023.

[191] Y. G. a. P. M. J. S. H. Lee, "Advanced frequency control and stability analysis for current-limited grid-forming inverters in weak grids," IEEE Transactions on Smart Grid, vol. 14, no. 4, pp. 2890–2904, July 2023.

[192] AEMO, "Grid Forming Technology Access Standards," AEMO, 2025.

[193] EPRI, "Voltage quality enhancement of distribution network based on unified power quality conditioner with BESS," *Frontiers in Energy Research,* 16 September 2024.

[194] V. M. a. B. Bahrani, "Grid-forming inverters as a grid-strengthening asset," Monash Energy Institute Technical White Paper, Sep. 2021.

[195] S. G. e. al., "Visualizing uncertainty in the future power system control room," AR-PST Stage 4 Research Report, 2025.

[196] M. University, “Control Room of the Future: The Human-Machine Interface,” AR-PST Stage 2/3 Implementation Reports, 2022–2024.

[197] E. M. G. J. L. a. M. N. M. A. Hossain, “Optimized Model-Free Frequency Control for Renewable Energy Integration in Islanded Power Systems,” IEEE Trans. Ind. Appl., vol. 62, no. 2, pp. 2084-2096, Aug. 2025.

[198] Schweitzer Engineering Laboratories, Inc. (Ritwik Chowdhury), “Review of SIR Calculations for Distance Protection and Considerations for Inverter-Based Resources,” Presented at the 51st Annual Western Protective Relay Conference Spokane, Spokane, Washington, October 22–24, 2024.

[199] B. S. K. K. a. S. A. S. Malik, “Critical Feature Selection for Machine Learning Approaches to Detect Ransomware in Smart Grids,” Int. J. Comput. Digit. Syst., vol. 11, no. 10, pp. 1167–1176, Mar. 2022.

[200] S. C. a. S. N. Thennadil, “An analysis framework for clustering algorithm selection with applications to spectroscopy and grid data,” PLoS One, vol. 17, no. 3, Art. e0266369, Mar. 2022.

[201] T. R. Sanni, “Hierarchical Control of Islanded Microgrids with High Renewable Penetration,” Charles Darwin University Research Repository, 2023.

[202] M. A. Hossain, “Integration of Green Hydrogen for Energy Storage and Dispatch in Grid-Connected Systems,” ERI Research Brief, 2023.

[203] M. J. R. N. S. G. a. S. G. J. Hernandez-Alvidrez, “Grid-forming Inverter Experimental Testing of Fault Current Contributions,” Sandia National Laboratories, Tech. Rep. SAND2022-2968, [Online]. Available: www.osti.gov, Albuquerque, NM, USA, 2022.

[204] M. R. A. M. N. a. E. F. S. Sanati, “A Comprehensive Review on Differential Protection Schemes in IBR-Dominated Microgrid,” IEEE Access, vol. 12, pp. 156172-156193, doi: 10.1109/ACCESS.2024.3485741, 2024.

[205] B. H. a. A. W. R. van Herel, “Managing Fuse Protection in Low-Voltage Networks with Distributed Generation,” Green Grid, University of Canterbury, Tech. Rep. [Online]. Available: ir.canterbury.ac.nz, Christchurch, New Zealand, Aug. 2019.

[206] P. B. E. R. D. L.-P. N. M. a. J. D.-F. D. Carrascal, “Fault Prediction and Reconfiguration Optimization in Smart Grids: AI-Driven Approach,” Future Internet, vol. 16, no. 11, p. 428, [Online]. Available: https://doi.org/10.3390/fi16110428, Nov. 2024.

[207] S. S. B. F. C. A. A. S. W. a. J. I. M. Aboelhassan, “Artificial Intelligence-Based Protection for Smart Grids,” Energies, vol. 15, no. 13, p. 4933, doi: 10.3390/en15134933, Jul. 2022.

[208] R. G. K. N. T. a. B. J. Viswanathan, “Line Protection Solutions for Multiple IBR Interconnections with Unfavorable Conditions in an Incumbent Utility Infrastructure”.*78th Annual Georgia Tech Protective Relaying Conference.*

[209] R. A. F. L. a. P. L. M. Bini, “Field Cases Analysis of Protection Schemes Applied to Transmission Lines Connecting Inverter-Based Resources to the Grid,” *52nd Annual Western Protective Relay Conference, Spokane, WA, USA,* 28 October 2025.

[210] Paulo Max Maciel Portugal, Renato Weingartner Pernas, Lucas Vernot Amaral, and Renata Ribeiro Silva, Furnas Centrais Eletricas S.A. Ricardo Abboud, Rafael Cernev, and Marcos Cabral, Schweitzer Engineering Laboratories, Inc., “Case Study: Modern RAS Applied to Furnas 765 kV Transmission Corridor Improves Itaipu Power Plant and Brazilian Power System Stability,” 2022.

[211] Hitachi Energy, “Release of Relion 670 series version 2.2," Document 1MRG046060,,” Hitachi, [Online]. Available: https://www.hitachienergy.com/news-and-events/product-releases/. [Accessed 11 March 2026].

Appendix A –Technical Postulate – Hybrid Supervisory Logic for Weak-Grid Protection Using Internal Control-State Metrics

Author & Concept Lead: Alex McLeod / Amplitude Consultants

Year: 2026

Overview and Context

As a supplemental contribution to this study, this appendix introduces an independent conceptual research framework developed by the author to address the emerging "speed gap" in protection performance within inverter-dominated and weak-grid power systems. While the main report focuses on the contracted scope, this appendix proposes a theoretical methodology that leverages internal inverter control-state excursions as potential supervisory signals for accelerating conventional IEC 60255-compliant protection logic.

Hybrid protection schemes that incorporate supervisory elements responsive to system inertia have been explored in literature and shown potential effectiveness in networks with mixed synchronous and inverter-based resources (IBRs)[20]. In such systems, physically meaningful deviations—such as frequency or voltage excursions—provide observable triggers for fast protection decisions. However, as system inertia declines and IBR penetration approaches 100%, these physical signals become increasingly dependent on inverter control dynamics. This shift reduces the observability of incipient faults and compromises the reliability of conventional protection triggers.

In networks with very low short-circuit strength (SCR < 2) or near-complete IBR penetration, frequency behaviour becomes control-dependent, and fault currents are heavily suppressed or delayed by inverter current-limiting controls. Under these conditions, traditional frequency-based supervisory schemes lose reliability [20], and RMS-based protection elements may operate too slowly or incorrectly.

This appendix postulates an alternative supervisory paradigm: using internal inverter control signals—rather than terminal measurements—to provide a high-speed fault-validation input to conventional IEC-compliant protection relays. This approach enables sub-cycle decision-making for blocking, trip acceleration, and adaptive settings selection, without compromising security.

Motivation: The Protection "Speed Gap" in IBR-Dominated Networks

IBRs employ fast-acting digital control loops to regulate active/reactive power, synchronize with the grid, and enforce current limits during faults. Internal control variables—such as direct-quadrature reference frame (dq)-axis currents, DC-link voltage, and PLL states—respond within a few milliseconds, often preceding observable changes at the point of common coupling (PCC)[21].

---

[20] L. Fan et al., "Mechanism analysis of dynamic phenomena in power grids with high penetrations of IBRs," U.S. DOE, 2023.

[21] Y. Luo et al., "Transient synchronous stability analysis … dual-sequence PLL-based VSC during asymmetric grid faults," *Protection and Control of Modern Power Systems*, 2023.

By contrast, conventional protection functions rely on network-level quantities such as RMS voltage depression, current magnitude, or frequency deviation. In weak-grid conditions, these external signals may:

- **Rise slowly**, delaying relay pickup;
- **Remain below threshold**, due to inverter current limiting; or
- **Exhibit distortion** caused by control interactions, harmonics, unexpected phase contributions during faults, or changing negative sequence impedance.

This temporal mismatch may create a protection speed gap, where internal inverter stress or loss of synchronism occurs well before conventional relays detect a fault. The result is delayed tripping or mis-operation, particularly in systems with low short-circuit strength (SCR < 2) or high IBR penetration.

The postulate presented herein conceptually addresses this gap by treating inverter internal control excursions as early-warning signals, not as direct trip commands. These signals may provide sub-cycle fault validation to IEC 60255-compliant relays, potentially enabling faster and more secure decision-making for:

- **Blocking** (to prevent false trips during benign oscillations);
- **Trip acceleration** (when stress indicators confirm a genuine fault); or
- **Adaptive settings selection** (for weak-grid conditions).

Conceptual Architecture: Decoupled Intelligence and Execution

The proposed architecture adopts a deliberately decoupled functional structure to maintain compliance with established protection philosophies while introducing theoretical high-speed supervisory capability:

- **Inverter (Intelligence Layer):** Acts as a diagnostic engine, monitoring internal control states (e.g., PLL coherence, dq-axis current excursions, DC-link voltage dynamics). When abnormal excursions indicative of fault stress is detected, the inverter generates a binary **Fault_Validation_Flag** within a few milliseconds.
- **Protection Relay (Execution Layer):** Remains fully IEC 60255-compliant, operating on conventional measurements (voltage, current, frequency) and executing standard protection logic without modification.

The inverter-derived flag is presented as a conceptual supervisory enable, conditioning relay sensitivity or logic pathways—never as a standalone trip command. This separation ensures:

- **Preservation of security principles:** Relay decisions remain grounded in network-observable quantities.
- **Acceleration under suppressed-current or other weak-grid conditions:** The flag validates fault presence before RMS-based elements reach pickup, enabling faster blocking, trip acceleration, or adaptive settings selection.

This architecture introduces predictive intelligence without compromising deterministic execution, bridging the speed gap in weak-grid environments while maintaining interoperability with existing relay standards.

Control-Theoretic Foundations: PLL Behaviour

Steady-State Behaviour and Theoretical Justification

In grid-following inverter-based resources, the Synchronous Reference Frame PLL (SRF-PLL) estimates the instantaneous grid phase angle θ_g and frequency ω_g by minimizing the phase error between the measured terminal voltage and an internally generated rotating reference. Synchronization is achieved by forcing the quadrature-axis voltage component toward zero:

$$v_q \to 0$$

This condition aligns the rotating d-axis with the grid voltage phasor. In steady state:

- v_d represents the grid-voltage magnitude;
- v_q reflects residual phase error (nulled at equilibrium).

Let θ_{pll} be the PLL's internal phase and ω_{pll} its instantaneous angular frequency. At equilibrium, the estimated phase evolves linearly:

$$\theta_{pll}(t) = \omega_0 t + \theta_0$$

Taking the time derivative yields:

$$\dot{\theta}_{pll}(t) = \omega_{pll}(t) \approx \omega_0$$

where ω_0 is the nominal grid frequency (e.g., $2\pi \cdot 50$or $2\pi \cdot 60$rad/s). Consequently, under balanced steady-state conditions:

$$\omega_{pll} \approx \omega_0, \qquad \dot{\theta}_{pll} \approx \omega_0$$

These equalities follow from the SRF-PLL control objective and are widely established in control literature on grid-synchronized converters.

2026 design practice (loop filter & feedforward): A PI loop filter processes v_q to produce a frequency correction $\Delta\omega$. With frequency feedforward,

$$\omega_{pll}(t) = \omega_{ff} + \Delta\omega(t), \qquad \omega_{ff} \approx \omega_0,$$

the PI focuses on deviations, enhancing transient tracking. The VCO/integrator then produces θ_{pll} by integrating ω_{pll}. In polluted or weak grids, prefilters (e.g., SOGI, notch filters) are typically employed to stabilize v_q and reduce harmonic/unbalance artefacts.

Small-Signal Interpretation

Linearisation of the SRF-PLL [22] around its locked operating point yields a canonical second-order form. A convenient representation linking grid-phase disturbance $\Delta\theta_g$ to the PLL's frequency correction $\Delta\omega_{\text{pll}}$ is:

$$\frac{\Delta\omega_{pll}(s)}{\Delta\theta_g(s)} = \frac{K_p s + K_i}{s^2 + K_p s + K_i}$$

where K_p and K_i are the PI gains. In steady state ($s \to 0$), integral action eliminates residual frequency error:

$$\lim_{s\to 0} \Delta\omega_{pll}(s) = 0$$

Parameterisation exposes bandwidth/damping trade-offs:

$$\omega_n = \sqrt{K_i}, \qquad \zeta = \frac{K_p}{2\sqrt{K_i}}$$

(under common normalisation assumptions). Larger ω_n increases speed; adequate ζ is essential to avoid overshoot and oscillatory synchronism loss in weak grids.

Behaviour During Load Variations (Non-fault)

During large but non-fault load changes, grid frequency deviations are typically small and slowly varying:

$$\omega_{\text{pll}}(t) = \omega_0 + \Delta\omega(t), \qquad \dot{\theta}_{\text{pll}}(t) = \omega_{\text{pll}}(t).$$

The identity $\dot{\theta}_{\text{pll}} \equiv \omega_{\text{pll}}$ reflects coherent internal state evolution (voltage controlled oscillator (VCO) integration of the frequency estimate). Under these conditions, the PLL remains locked and no impulsive behaviour is observed.

Inverter-Derived Supervisory Signals

Three categories of internal inverter signals are proposed as inputs to the supervisory logic.

dq-Axis Current Excursions

Sudden deviations from steady-state references indicate abnormal grid interaction:

$$| I_d - I_d^{ref} | > \Delta I_d^{th} \text{or } | I_q - I_q^{ref} | > \Delta I_q^{th} \qquad (6)$$

DC-Link Voltage Excursions

[22] Linearised SRF-PLL models demonstrate integral elimination of steady-state frequency error under balanced conditions, see V. Kaura and V. Blasko, "Operation of a phase-locked loop system under distorted utility conditions," *IEEE Transactions on Industry Applications*, vol. 33, no. 1, pp. 58–63, 1997.

Fault conditions may produce abrupt DC-link voltage deviations due to power imbalance:

$$\frac{V_{dc}^{pre} - V_{dc}^{fault}}{V_{dc}^{pre}} > \varepsilon \qquad (7)$$

PLL Frequency/Phase Deviation

Faults induce rapid changes in estimated grid frequency ω_{pll} or phase θ_{pll}. Detection can provide a trigger signal before AC current rises.

Composite PLL-Derived Supervisory Indicator (Postulate)

Building on the established dynamics of PLL frequency and phase estimation, define the PLL Internal Coherence Deviation (PICD) to capture incipient control-state stress:

$$PICD = \alpha \mid \omega_{pll} - \omega_0 \mid + \beta \mid \dot{\theta}_{pll} - \omega_0 \mid \qquad (8)$$

where:

- ω_{pll} is the estimated grid frequency in rad/s;
- $\dot{\theta}_{pll}$ is the time derivative of the estimated PLL phase angle, expressed in rad/s;
- ω_0 is nominal system frequency in rad/s; and
- α, β are dimensionless weighting factors tuned to grid strength.

Interpretation. PICD is not a frequency estimator. It is a stress-oriented supervisory metric derived from internal PLL states that indicates incipient loss of control coherence. While other control states (e.g., dq-current or DC-link excursions) may exhibit correlated stress, they are excluded from the PICD definition adopted here and remain candidates for future extension.

Optional normalization (dimensionless):

$$\text{nPICD} = \alpha \frac{\mid \omega_{\text{pll}} - \omega_0 \mid}{\omega_0} + \beta \frac{\mid \dot{\theta}_{\text{pll}} - \omega_0 \mid}{\omega_0}$$

or bandwidth-aware

$$\text{nPICD}_{\text{bw}} = \alpha \frac{\mid \omega_{\text{pll}} - \omega_0 \mid}{\omega_n} + \beta \frac{\mid \dot{\theta}_{\text{pll}} - \omega_0 \mid}{\omega_n}.$$

These forms ease threshold harmonisation across ratings/regions and couple sensitivity to designed response speed.

Optional coherence cross-term:

$$\text{PICD}^{+} = \text{PICD} + \gamma \mid \omega_{\text{pll}} - \dot{\theta}_{\text{pll}} \mid$$

Small γ(e.g., 0.2α–0.5α) flags internal inconsistency introduced by filtering or numerical delays.

Behaviour of the Composite Indicator

Steady-State Behaviour:

Under balanced steady-state conditions, integral action enforces:

$$\omega_{pll} \approx \omega_0, \qquad \dot{\theta}_{pll} \approx \omega_0$$

hence PICD ≈ 0 when the PLL is locked and deviations from nominal frequency/phase rate are negligible.

High Load Variability (Non-fault)

During large but non-fault load changes, both ω_{pll} and $\dot{\boldsymbol{\theta}}_{\mathrm{pll}}$ evolve smoothly. PICD exhibits modest excursions, supporting discrimination between legitimate operating dynamics and fault-induced disturbances.

Fault and Weak-Grid Conditions

In weak-grid or inverter-dominated systems, voltage depression, phase jumps, or unbalance may push PLL dynamics into nonlinear or stressed regimes, characterised by:

- rapid frequency estimation deviation (spikes/overshoot);
- impulsive or oscillatory phase-rate behaviour; or
- loss of tracking margin prior to significant AC current rise.

These effects originate at the control level and precede terminal quantities, making PICD a sensitive early-warning indicator.

Bandwidth and Equilibrium Limits

Around the locked point, the SRF-PLL behaves as a second-order control loop with finite bandwidth determined by PI gains and effective grid impedance. Within this bandwidth, slow frequency variations and load-induced phase changes are tracked accurately ($\omega_{\mathrm{pll}} \approx \omega_0$, $\dot{\theta}_{\mathrm{pll}} \approx \omega_0$), yielding negligible PICD. Disturbances that exceed bandwidth (faults, deep sags, abrupt phase changes) manifest as transient divergence between ω_{pll} and $\dot{\theta}_{\mathrm{pll}}$, due to filtering, control lag, and nonlinear saturation. In severe sags/unbalance, a stable equilibrium with $v_q = 0$ may not exist, rendering the PLL objective infeasible and necessitating controlled disconnection.

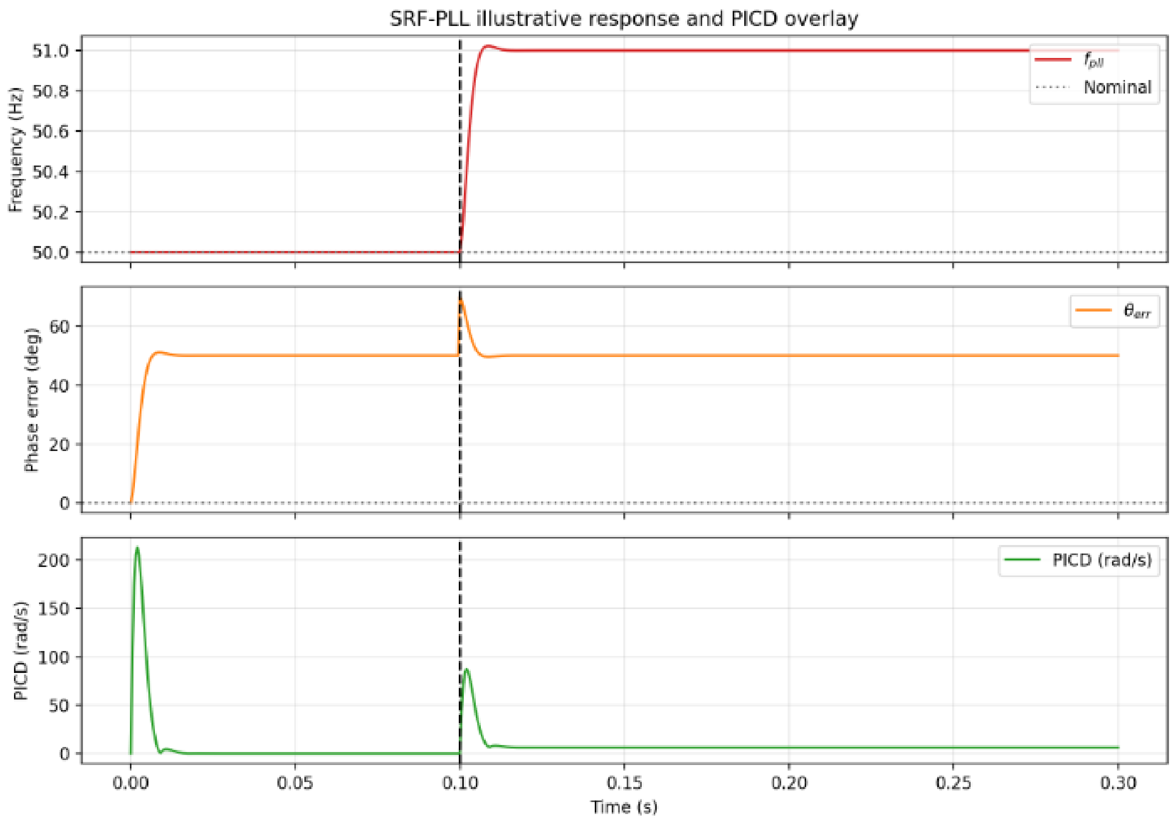
Illustrative Transient PLL example

A SRF-PLL subjected to a phase-angle step exhibits a characteristic transient: the detected frequency and phase-rate initially deviate (including overshoot/ringing depending on $\omega_n, \zeta$and prefilters) and then re-converge under integral action. PICD rises sub-cycle during the disturbance and returns near zero once lock is re-established.

The following figure illustrates the dynamic relationship between PLL internal states and the proposed PICD metric during a phase-angle disturbance. While the PLL frequency and phase error settle over tens of milliseconds, PICD responds almost instantaneously, exceeding its threshold within a few milliseconds and returning near zero once lock is restored [21].

This behaviour demonstrates PICD's potential as a fast, stress-oriented supervisory indicator, enabling relay logic to accelerate or adapt protection decisions without compromising IEC 60255 compliance.

Figure 10 – SRF-PLL transient response and PICD overlay during a phase-angle disturbance [23]



The PLL frequency estimate and phase error exhibit overshoot and oscillatory recovery following a disturbance at 0.10 s. PICD spikes sharply at the disturbance and collapses toward zero as the PLL re-establishes lock, providing a sub-cycle supervisory signal for relay logic.

Relay Integration and Supervisory Handling

The inverter-generated Fault_Validation_Flag, derived from the PICD metric (PLL Internal Coherence Deviation), can be communicated to the protection relay using standard protocols such as IEC 61850 Generic Object-Oriented Substation Event (GOOSE) [24], consistent with IEC TR 61850-90-4 for fast peer-to-peer messaging.

[23] Figure illustrative only and does not represent empirical or simulation data.

[24] M. Higginson and P. Pabst, "Design and Implementation of an IEC 61850 GOOSE Based Protection Scheme for an Islanded Power System," *Ameren Illinois*, IEEE 2000-R160.

PICD is computed from internal PLL states—specifically the estimated grid frequency (ω_{pll}) and instantaneous phase rate $(\dot{\theta}_{\text{pll}})$—and can be implemented within modern inverter controllers. Access to these variables is typically available through diagnostic or telemetry interfaces (e.g., Modbus, CAN, or proprietary channels), enabling the calculated PICD to be exported as a binary supervisory flag.

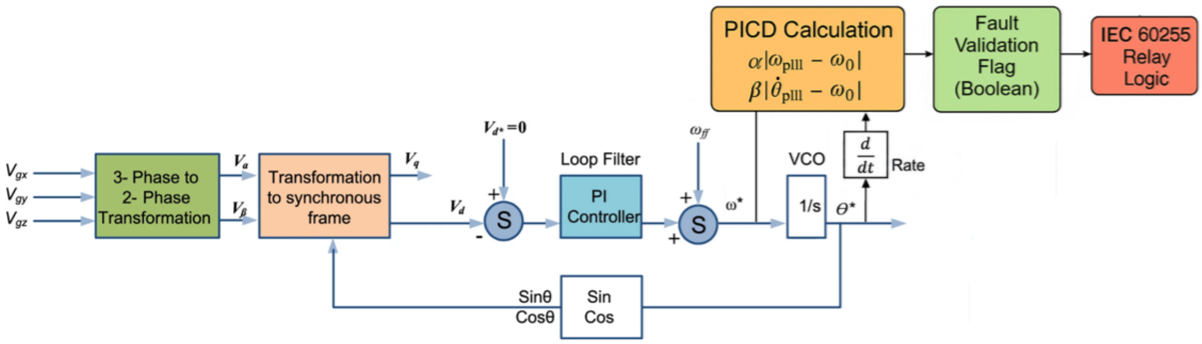
Both terms in PICD have units of rad/s, and under balanced steady-state conditions:

$$\omega_{\text{pll}} \approx \omega_0, \qquad \dot{\theta}_{\text{pll}} \approx \omega_0, \qquad \text{PICD} \approx 0,$$

reinforcing that PICD is a stress-oriented supervisory indicator, not a frequency estimator.

Figure 11 illustrates the SRF-PLL control loop and the PICD calculation block. Internal PLL states $(\omega_{\text{pll}}, \dot{\theta}_{\text{pll}})$ feed the PICD metric, which generates a Fault_Validation_Flag for IEC 60255-compliant relay logic via IEC 61850 GOOSE or equivalent fast communication channels.

Figure 11 – SRF-PLL: Synchronous Reference Frame Phase-Locked Loop



Upon reception of the Fault_Validation_Flag, the relay may:

- Shift to a more sensitive settings group, lowering pickup thresholds for overcurrent or undervoltage elements;
- Enable or disable selected protection elements through blocking/unblocking logic; or
- Permit accelerated operation of conventional trip functions, provided local measurement criteria are satisfied.

Practical implementation requires tuning the PICD weighting factors (α, β) to account for grid strength, inverter type and control dynamics. HIL or Controller-in-the-loop (CIL) testing is recommended to validate that the signal accurately reflects genuine control stress.

Importantly, this supervisory mechanism:

- Does not initiate a trip independently;
- Does not alter relay reach, directionality, or grading philosophies; and
- **Ensures compliance with IEC 60255**, so all tripping decisions remain dependent on conventional relay measurements and logic.

Unique Contribution and Research Significance

This postulate represents a conceptual shift from observing inverter behaviour at the power-system interface to formalising internal inverter control excursions as deterministic, system-level supervisory logic for protection. Unlike conventional adaptive schemes that rely exclusively on terminal measurements, the proposed supervisory quantity is derived from internal control states that evolve on millisecond timescales—well before observable changes in network current, voltage or frequency.

Because these internal states are not directly measurable by traditional protection relays, the supervisory signal cannot be reconstructed using standard IEC 60255 measurement principles. Its formulation therefore defines a new inverter–protection interface, where inverter control intelligence is used solely to condition or validate conventional protection functions, rather than replace them.

Accordingly, this contribution is presented as a research postulate, not an immediately deployable protection function. Its significance lies in:

- Establishing a formal framework for integrating inverter internal dynamics into future hybrid protection architectures;
- Providing a foundation for analytical validation, hardware-in-the-loop testing, and standardisation activities in inverter-dominated power systems; and
- Enabling sub-cycle supervisory capability without compromising IEC compliance or established grading philosophies.

This approach anticipates the evolving needs of low-inertia, high-IBR networks and offers a pathway toward next-generation protection schemes that combine deterministic relay logic with predictive inverter intelligence.

Path to Validation and Future Research

[Add description to explain the purpose of the following activities.]

Validation Pathway

Control-Level Simulation

Perform time-domain EMT simulations to characterise the behaviour of internal supervisory indicators across:

- Fault types (symmetrical and asymmetrical);
- Load disturbances;
- Inverter operating modes; and
- System strengths, including very low SCR conditions.

Controller- and Hardware-in-the-Loop (CIL / HIL) Testing

Validate signal observability, noise immunity, and repeatability using real inverter control hardware or representative firmware models under realistic dynamic conditions.

Latency Characterisation

Quantify end-to-end latency from inverter control excursion to relay reception (e.g., via IEC 61850 GOOSE), and other communication limitations ensuring total detection and communication delays remain within protection-relevant timeframes (≈10 ms).

Protection Performance and Coordination Studies

Assess dependability and security impacts when the supervisory signal is used to condition conventional relay elements, confirming that established coordination, selectivity, and grading philosophies are preserved.

This structured approach aligns with contemporary best practice for introducing control-informed protection concepts and provides a clear pathway for future collaborative research, pilot studies, and standardisation consideration.

Research Gaps and Opportunities:

The proposed supervisory postulate highlights several open research gaps requiring further investigation prior to practical adoption:

- Internal Signal Selection and Combination
- Determine the optimal mix of internal inverter signals (e.g., dq-axis current excursions, DC-link voltage dynamics, PLL-derived frequency/phase deviations, power imbalance indicators) to maximise fault sensitivity while minimising nuisance operation.
- Adaptive Threshold Tuning
- Develop systematic methods for threshold selection and adaptive tuning that account for:
  - Network strength;
  - IBR penetration levels; and
  - Inverter control modes (grid-following vs grid-forming).
- Integration with Existing Adaptive Protection Schemes
- Explore how inverter-derived supervisory signals can complement established adaptive approaches (e.g. grouped settings, blocking schemes, sensitivity shifting) to enhance speed and dependability in high-renewable networks.
- Robustness to Control and Measurement Disturbances
- Evaluate susceptibility to inverter control noise, harmonics, and transient disturbances, ensuring reliable discrimination between genuine faults and benign conditions.
- Frequency-Based Supervisory Extensions
- Investigate the role of frequency-related internal control signals, including RoCoF and synthetic inertia responses, as potential supervisory inputs to IEC over-/under-frequency elements in weak grids.
- Sequence Component–Based Indicators

- Examine negative-sequence current and voltage excursions derived from inverter internal measurements as early-warning indicators for asymmetrical faults or incipient voltage instability.
- Predictive and Pre-Emptive Protection Concepts
- Assess feasibility of predictive or pre-arming strategies leveraging inverter control loop estimates or forecasts to enable relay action prior to observable network current rise.
- Communication and Latency Constraints
- Quantify end-to-end latency for mapping internal inverter flags to external protection devices (e.g. via IEC 61850 GOOSE), ensuring total delays remain within protection-relevant timescales (≈10 ms).

Closing Statement

This appendix introduces an independent conceptual research framework originated and developed exclusively by the author to address inverter-informed control-state protective signal processing.

The framework serves to guide future exploration, validation, and the author's subsequent academic research, independent of the contracted deliverables of this study and is provided to support broader research and innovation objectives. The methodologies and metrics presented (e.g. PICD) are conceptual research postulates, not currently deployable protection functions; they serve to guide future exploration, validation, and potential collaborative development.

Disclaimer: The concepts, figures, and performance descriptions presented in this appendix are theoretical and illustrative only. They do not represent validated or deployable protection functions. No empirical simulation or hardware testing has been performed for the examples shown.

Appendix B – Conceptual Critical Clearing Time (CCT) Equation

To support analysis of protection coordination in inverter-dominated microgrids, we propose a conceptual equation for the Critical Clearing Time (CCT):

$$\text{CCT} \propto \frac{H \mid V \mid^2}{\mid I_f \mid \cdot \mid Z_f \mid \cdot \tau} \qquad \text{equation A.1}$$ [25]

Where:

- H= system inertia (synchronous or equivalent)
- $\mid V \mid$= pre-fault voltage magnitude
- $\mid I_f \mid$= fault current magnitude
- $\mid Z_f \mid$= fault path impedance
- τ= effective inverter fault time constant

Justification and Literature Basis

1. System Inertia (H)
    - In low-inertia networks, such as isolated microgrids, the energy available to support voltage and frequency during faults is reduced, directly affecting allowable clearing times [(NERC), 2017; EPRI, 2018].
    - Field studies in inverter-rich microgrids demonstrate that lower effective inertia necessitates shorter clearing times to maintain stability [El-Sayed & Sati, 2023; Lyu et al., 2024].
2. Voltage Magnitude ($\mid V \mid$)
    - Pre-fault voltage affects the instantaneous power delivered into a fault, influencing rotor angle excursions and voltage recovery [Reno & Callaway, 2021].
    - Observed in both microgrid testbeds and simulated weak-grid scenarios, voltage level directly scales the energy that must be interrupted by protection devices [B.K. Johnson & M. Ropp, 2019].
3. Fault Current ($\mid I_f \mid$)
    - Fault currents from inverters decay rapidly due to inner current control loops, limiting the magnitude available for traditional overcurrent relays to detect and clear faults [CIGRÉ TB 859, 2022; El-Sayed & Sati, 2023].
    - The exponential decay can be approximated as $I_{sc}(t) = I_{f,peak} e^{-t/\tau} + I_{ss}$, frequently cited in inverter modeling literature [B.K. Johnson & M. Ropp, 2019].

[25] Equation A.1 is a conceptual synthesis reflecting the observed relationships between system inertia, voltage, inverter fault current, network impedance, and inverter control dynamics. While the specific form has not been validated experimentally, it aligns with trends reported in field studies, simulation-based protection research, and theoretical modelling of inverter-limited fault contributions and weak-grid stability.

4. Fault Impedance (| Z_f |)
   - The path impedance between source and fault influences the voltage drop and energy dissipation during the fault [EPRI, 2018].
   - Accounting for Z_f ensures the CCT formulation reflects both system topology and line characteristics in weak or islanded microgrids.
5. Inverter Time Constant (τ)
   - Inverters' inner current control loops impose current-limiting behaviour described by $i_{\text{fault}}(t) = i_{\text{max}}(1 - e^{-t/\tau_c})$[B.K. Johnson & M. Ropp, 2019; CIGRÉ TB 859, 2022].
   - This time constant governs the fault current rise and decay, thereby impacting the maximum allowable clearing time for stable operation.