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Topic 6 Stage 4 System Services

Final Report

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Important disclaimer

Simplified NEM model disclaimer

The following caveats were originally applied to the University of Adelaide 14-generator, 59-bus model [1] which forms the basis of much of this work. It therefore equally transfers to its derivatives used in this research.

The model of the power system used in this document is loosely based on the southern and eastern Australian networks. Therefore,

- It does not accurately represent any particular aspect of those networks;
- The model should not be used to draw any conclusions relating to the actual performance of the networks comprising the southern and eastern Australian grid, either for any normal or any hypothetical contingency condition;
- The model is suitable for educational purposes / research-oriented analysis only.

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1 Acknowledgments

The research presented in this report was funded by CSIRO, Australia's national science agency, and carried out as part of CSIRO's contribution to the initiatives of the Australian Power Systems Renewables transition. This research supports Australia's transition to a stable, secure and affordable power system and contributes to critical research identified by the Consortium required to accelerate the decarbonisation of our electricity grid.

The research presented in this report was supported by the Australian Energy Market Operator, a stakeholder in the AR-PST Consortium, who provided subject matter expertise towards these research findings.

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Executive summary

Services refers to characteristic or function of the power system which helps maintain a robust and resilient grid. With the Australian system becoming increasingly dominated by inverter-based resources (IBRs), and the increased understanding that the previous paradigm of synchronous-machine based system services (such as voltage and frequency) are in fact comprised of many more nuanced components that IBRs may or may not elect or be capable of providing, it is important to revisit what services are both required and may not be inherently provided as the system continues to have ever-higher penetration levels of inverter based technology.

The work completed in Stage 4 of the Services program can be broken down into four major areas:

- Revisiting the research roadmap and stepping back to consider a more comprehensive set of essential technical needs of the power system, from slow requirements such as system balancing, down to very fast requirements such as fault current performance.
- Understanding how such power system technical needs evolve as the National Energy Market (NEM) mainland increases in shares of IBR generators, through the development of a reduced order wide-area Electromagnetic Transient (EMT) model of the NEM.
- Through EMT modelling, investigate the operation of the NEM without any synchronous machines, understand how NEM stability and characteristics change, and what steps should be taken to maintain stability.
- Exploring how many of the conclusions based on the EMT simulations above can be corroborated by the use of more simple and faster Phasor Domain Transient (PDT) modelling and highlight where any key differences may occur.

Note that this stage intentionally considered a set of detailed technical needs of the NEM over analysis and conclusions on whether maintain such characteristics should be provided as a service (i.e., through a market mechanism), or as a mandatory technical requirement. This is due to the need to consider a far wider and more nuanced set of system behaviours based on contemporary technology trends and modelling.

The following developments and insights were achieved through this Stage 4 work, noting that only a subset of technical needs of the power system could be evaluated given the time available:

- A new services roadmap was developed with a comprehensive set of system technical needs appropriate for a system with increasingly high shares of IBR devices constituting its generation fleet.
- A series of simplified and sharable NEM models were developed that represents the evolution of the NEM over the next 10 years (2024 to 2034), including:
  - Introduction of new, major network projects as identified by the AEMO ISP that materially alter the topology of the NEM, and hence, its dynamics.
  - Aggregate representations of 18 REZs and 2 major battery projects as outlined in the AEMO ISP.

- Identification of an approximate minimum amount of grid-forming technology required to maintain stability of the NEM for the scenarios considered in this work, being a 30% grid-forming ratio (including where a system is devoid of any rotating machinery).
  - It was found that at the rate the generation mix is changing, the deployment of GFM IBR to support the needs of the power system must begin effectively immediately.
- Identification of two new phenomena that occur in very high IBR penetration systems (even when sufficient grid-forming capability is maintained to prevent system instability):
  - Larger and wide-spread phase angle jumps during a fault, indicating that the entire power system may simultaneously shift in response to a disturbance (opposed to the previous situation where synchronous machines offered a "decoupling" of regions.
  - Overvoltages during faults were observed for very remote credible disturbances, indicating a potential new form of coupling, most likely related to the phase angle shift phenomenon.
- The total fault current provision from systems with high IBR penetration may not necessarily have a reduced magnitude[1], as far more IBR devices will likely need to be online to achieve the same dispatchable output of that received from a synchronous machine (i.e., IBR have lower capacity factors), however the quality of the fault current present in the system may have materially altered, including changing magnitudes during a fault and increased current waveform distortion.
- While the PDT model showed very similar results to the EMT model in terms of total fault current contribution levels, residual voltages during faults and approximate phase-angle changes, there were notable differences in some phenomena observed (e.g., in-fault remote overvoltages not present in PDT) and an increased sensitivity of the PDT model to system loading, with lightly-loaded PDT cases returning optimistically stable results, but heavily loaded cases returning more pessimistic unstable results when compared to EMT simulations.

This being the first stage following a revamped Services roadmap, there is extensive potential for additional technical needs to be evaluated in the power system through EMT modelling, along with the important step of determining the most efficient way in which to classify how each technical need should be delivered to the power system (i.e., through a market-based mechanism or through a technical standard). Further work in this space may include:

- Investigation of the Services with a residual high-priority rating as determined in the new Topic 6 roadmap.
- Using the developed EMT models to undertake an evaluation of the performance of protection relays in scenarios with changed qualities of fault current components.

[1] From a whole-of-system reference. From an individual unit reference, each IBR device will have considerably less fault current compared to that which a synchronous machine can provide.

- Inclusion of DER and CER EMT models in the evaluation to determine how load-side performance may be impacted or impacts the overall system resilience when IBR generation is dominant.
- An expansion of the use of vendor-specific EMT models of generators to determine if there are material differences between the generic models predominantly used in this work versus a wide set of OEM devices.
- Further investigations of how natural resonant points of the power system change as synchronous machines are removed.

2 Introduction

Services refers to characteristic or function of the power system which helps maintain a robust and resilient grid. With the Australian system becoming increasingly dominated by inverter-based resources (IBRs), and the increased understanding that the previous paradigm of synchronous-machine based system services (such as voltage and frequency) are in fact comprised of many more nuanced components that IBRs may or may not elect or be capable of providing, it is important to revisit what services are both required and may not be inherently provided as the system continues to have ever-higher penetration levels of inverter based technology.

2.1 Significance

The work being completed in this Stage and Topic is directly related to the evolution of the Australian power system as it evolves to an inverter-dominated paradigm. Specifically:

- The models being developed are of the mainland NEM (Section 3.1).
- The network developments being considered are based AEMO's ISP [2] and the Transmission Annual Planning Reports [3] [4] [5] [6] of Australian transmission network service providers (Section 4.2.2).
- The modelling of generator and REZ locations are based on published data [7] [8] [9] [10] [11] [12] [13] [14] [15] [16] [17] for the east-coast electricity system evolution (Section 4.2.2).
- The specific scenarios the wide-area models consider are based on the researcher's previous operational experience at AEMO, and are intended to represent realistic dispatch scenarios in the Australian-east coast network (Section 3.2.2).

Many of the insights are expected to reveal how system stability depends on the profile of generation dispatch setpoints across the power system (e.g., proportion of synchronous versus IBR) and the controller dynamics governing the behaviour of the inverter-based generators (e.g., grid-following versus grid-forming control). Additionally, the wide area network model will allow investigation of how best to source services, given the quintessentially Australian problem of very long distances between generation centres and load centres, and long distances between synchronous and IBR centres. Many of the investigations in this Stage will focus on the limits of IBRs that the power system can reliably accommodate, and conversely, what properties must IBRs offer to the power system to ensure secure uptake of such technologies. In this way, although the insights and conclusions will have been generated in an Australian context they are expected to be applicable to a variety of systems experiencing a similar ratios of IBR uptake. Where it is discernible that a specific conclusion is topology specific, efforts will be made to clearly flag this as such in the research output.

Furthermore, excluding any confidential or sensitive data used, the EMT models developed will be released to CSIRO to share with the research community to scrutinise, change, grow, or otherwise use as they see fit. Confidential models used in the analysis will be so identified and replaced for the model release with a non-confidential equivalent.

2.2 Previous stages

The Services area of AR-PST research did not run in the previous 2023-24 year. Prior to this, the roadmap and study efforts focused predominantly on traditional system normal services (i.e., general voltage and frequency provision). The last active research round focused heavily on frequency control of the NEM, hence this area, whilst certainly not neglected entirely, is not given priority for investigation in this Stage 4.

2.3 Stage 4 focus areas

This work focuses on how to identify the need for such technical characteristics which will be affected by the material change in generation technology away from synchronous machines to inverter-based resources (IBR) across several categories. Specifically, Stage 4 considers the following:

- Revisiting the roadmap and stepping back to consider a more comprehensive set of essential technical needs of the power system, from slow requirements such as system balancing, down to very fast requirements such as fault current performance. This work is based on up-to-date and comprehensive knowledge of technical and regulatory developments (Section 4.1).
- Such power system needs can be classified into true Services, Technical Requirements, a combination of both, which will be investigated in future research stages.

  N.B.: Services are considered to be provision of a technical quality to the power system with a compensation mechanism that allows efficient and competitive delivery (e.g., frequency control), while technical requirements are firm requirements factored into the design of the plant that support power system needs without any additional compensation (e.g., NER S5.2.5.x requirements).
- Understanding how such power system technical needs evolve as the National Energy Market (NEM) mainland increases in shares of IBR generators, through the development of a reduced order wide-area Electromagnetic Transient (EMT) model of the NEM (Section 4.2).
- Through EMT modelling, investigate the operation of the NEM without any synchronous machines (i.e., even without hydro and synchronous condensers, 100% IBR), understand how NEM stability and characteristics change, and what steps should be taken to maintain stability (Section 4.3).
- Exploring how many of the conclusions based on the EMT simulations above can be corroborated by the use of more simple and faster Phasor Domain Transient (PDT) modelling and highlight where any key differences may occur. Such insights in modelling

differences may potentially lead to faster turnarounds for planning conclusions (Section 4.4).

It is important to note that a portion of this work is to revisit the research roadmap itself, hence although all activities are broadly aligned with the original roadmap objectives (investigation of frequency and voltage control needs and metric identification and evaluation), a far broader set of potential system services (and hence, domains of analysis) have been identified. A brief discussion on prioritisation is provided in section 3.2.1.

3 Methodology

3.1 Model Development

It was identified in the roadmap refresh that in order to understand all potential technical needs of a system evolving to 100% IBR, it is important not to assume that the same services available today are both required or provided by the components expected to exist in 2034, and that they are the only services needed.

Instead, to evaluate without presupposition the technical needs and services the grid will require as it evolves, it was proposed to develop multiple simplified EMT models of the mainland NEM[2] which evolve over time, and observe the performance differences across many different technical aspects, as identified in the Roadmap refresh (Section 4.1). Figure 1 shows the major years evaluated (NEM model created for each year), and notes the end goal to determine how the technical needs will change between the current and final year evaluated.

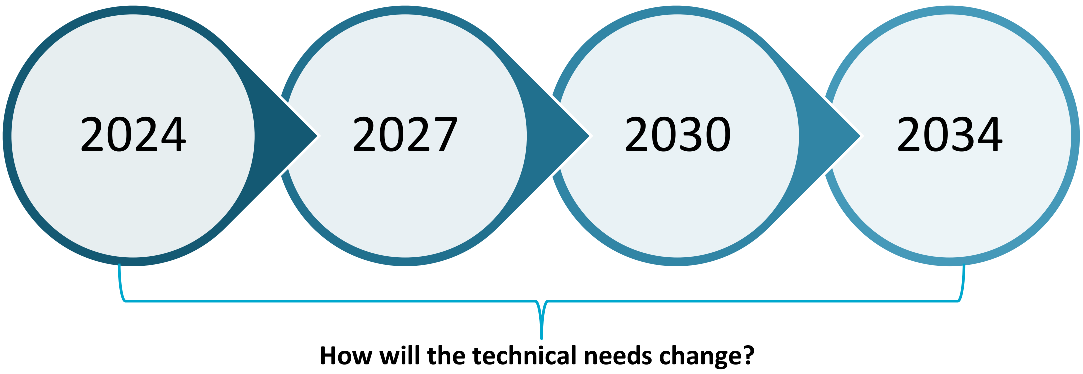


Figure 1 Considering the delta in performance between years

As the potential number of technical requirements an evolving grid may require could be vast, it was decided that in this research year, focus would be given to fast-quantities (i.e., aspects of grid performance likely to manifest during or just after a disturbance) rather than longer-term quantities such as frequency control, which itself had been the focus of previous research rounds in this space. Such quantities covered in this research year include:

- Fault current magnitude, sequence components, and quality;

[2] Note that Tasmania was not considered in this work as it is DC-coupled to the mainland NEM, and no appropriate HVDC EMT models were available.

- Phase angle changes during the fault;
- Voltage dips and suppression; and
- Inverter controller stability.

Once it was understood how these quantities change as the NEM evolves, further consideration can be given to the most effective and efficient way to deliver such technical requirements, either as a service or a technical requirement (to be covered in later research stages).

3.1.1 Modelling software

For EMT models, PSCAD™ v5.0.3 was used, with Intel® Fortran Compiler Classic 2021.12.0 (64-bit), part of the Intel® OneAPI suite.

3.1.2 Modelling Domain

With the base proposition of "we don't know what we're expecting to change precisely", the domain of EMT modelling was chosen as it can represent all power system phenomena from DC to MHz. This minimises the risk of accidentally omitting a need of the power system due to the inability of the modelling domain to represent it. However, EMT modelling does come with its own challenges, particularly:

- It requires considerably more effort to establish a functional model, compared to 'traditional' Phasor Domain Transient (PDT) modelling (e.g., PSS®E models).
  - It needs a lot more detailed models of generator systems, including modelling of highly detailed and potentially confidential control system algorithms.
  - If an OEM model is to be used, it cannot be openly shared due to their right to protect their intellectual property.
- It requires considerably more computational power to complete a simulation run, often in the order of an hour or more to run a 50-second wide-area case.
- Generally, EMT model management and versioning is not as refined and simple as can be found in PDT modelling tools.
- With at least an order of magnitude more detail contained in such an EMT model compared to a PDT model, there are many more possibilities for model development to go wrong.

Nevertheless, with a view that the model being developed will be both evolving throughout the AR-PST work and that it would be shared with the broader research community for use and importantly, scrutiny such that it can be improved, the EMT modelling domain was settled upon.

Modelling software

To create and run these EMT models, PSCAD™ v5.0.3 was used, with Intel® Fortran Compiler Classic 2021.12.0 (64-bit), part of the Intel® OneAPI suite.

3.1.3 Modelling approach

It was quickly established that it would not be possible to develop or use a 1:1 EMT model of the NEM's transmission system, and that a simplified model would be required for this work. This was based on:

- Obtaining a copy of AEMO's wide-area PSCAD™ model of the NEM for a non-NER specified use is impractical due to confidentiality constraints and the application of the new Security of Critical Infrastructure (SoCI) Act.
- Development of a new wide-area EMT model based on component data is impractical because:
  - The required details of the NEM's transmission system topology and characteristics is considered Confidential Information by the NER.
  - EMT models of the generators used throughout the transmission system are highly confidential and would require extensive confidentiality agreements to be established between the researchers and all active OEMs in the NEM – something unlikely to be resolved within the research timeframe.
  - The above notwithstanding, the effort required to develop such a model may take an excessively long time (potentially years) to complete.
- The computational power and software licencing costs required to run the whole-of-NEM wide-area EMT model is excessive, which would limit the accessibility and value to the wider research community.

Hence, the research has focused on basing the model on a well-established baseline simplified mainland NEM model: The University of Adelaide 14-generator, 59-bus model [1] (henceforth referred to as the 14/59 Model). This model is provided in PDT-form (specifically, PSS®E cases) and includes limited dynamic models of some synchronous plant only (generator, AVR and PSS only).

The 14/59 model was originally developed in 2010 and much has changed in the NEM since this time. As a starting point, the model was updated to better match the NEM arrangement of 2024. Specifically:

- Retired synchronous generators were removed from the model. See Table 1.
- Remaining synchronous generators were disaggregated to allow evaluation of lower system strength scenarios (i.e., when fewer synchronous generators within a station are online). See Table 2.
- Models of key IBR generators were included on buses closest to their appropriate geographical locations. See Section 4.2.2.

- Networks were augmented based on the expected state of the system at the end of the 2024 calendar year according to the AEMO ISP (i.e., inclusion of PEC stage 1). See Section 4.2.2.

The resultant updated 14/59 network model hence has the topological map shown in Figure 2.

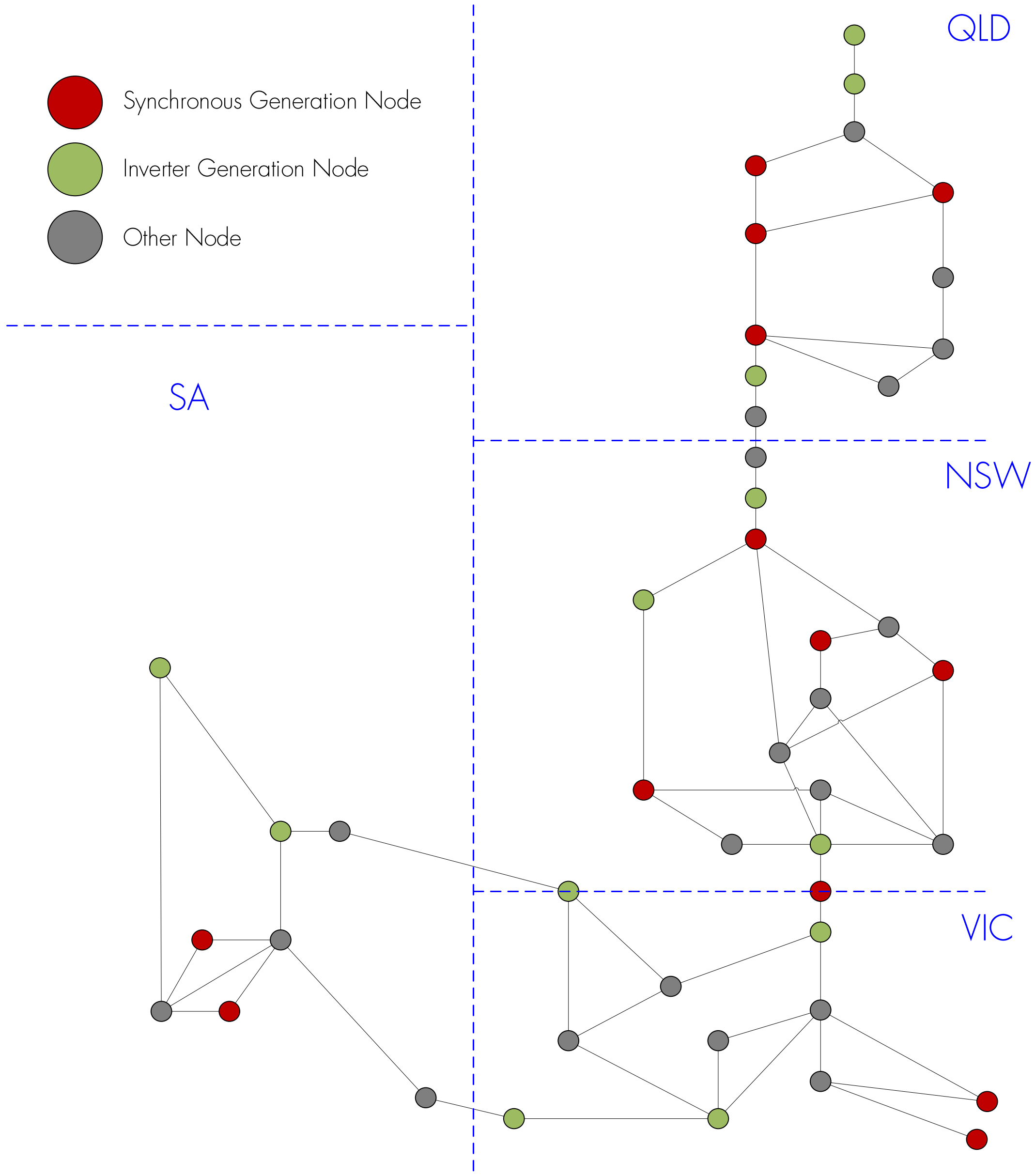


Figure 2 2024 Topological representation of mainland NEM model

This case had several variants created which considered different loading scenarios, and consequently different generation dispatch patterns. This case (still in PDT form) forms the basis for the development of a mating EMT model and its variants. More information is provided in Section 3.2.2.

Table 1 Relevant generator retirement years

Generator retired	Year
Northern Power Station (SA)	2016
Torrens Island B (SA)	2026
Eraring (NSW)	2027
Callide B (QLD)	2028
Yallourn (VIC)	2028
Bayswater (NSW)	2033
Vales Point (NSW)	2033

Table 2 Generator disaggregation

Generator	Original size (MVA)	Disaggregated size (MVA)
101 Murray/Tumut (VIC/NSW)	1333	167 – 8 units
201 Bayswater (NSW)	4000	667 – 6 units
202 Eraring (NSW)	2778	556 – 5 units
203 Vales Point (NSW)	2222	556 – 4 units
204 Mt. Piper (NSW)	4000	667 – 6 units
301 Loy Yang (VIC)	4667	667 – 7 units
302 Yallourn (VIC)	1333	444 – 3 units
401 Tarong (QLD)	1778	444 – 4 units
402 Callide (QLD)	888	444 – 2 units
403 Stanwell (QLD)	1778	444 – 4 units
404 Gladstone (QLD)	2000	333 – 6 units
501 Northern (SA)	667	Removed entirely
502 (Torrens Island)	1000	250 – 4 units
503 (Pelican Point)	667	333 – 2 units

Note: **The original aggregation of the 14/59 model is likely to have included other nearby plant, hence the disaggregated units may not be representative of the number of units physically present in the nominated station name. Instead, the intent of this disaggregation was to approximately match the unit size at the nominated station name, not the number of units. This was to allow variable dispatch to alter the system strength provision from the station in line with what may actually occur.**

3.1.4 Network Model

For the initial 2024 representation, the PDT network model was translated into the EMT domain. This translation was completed using the commercial tool PRSIM™, which allows a direct mapping between PDT and EMT elements. This conversion forms the basis for all following models and scenarios. Specific settings included:

- Given the relatively small number of network nodes, a single network case was developed.

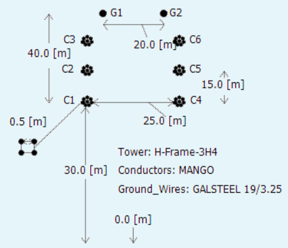
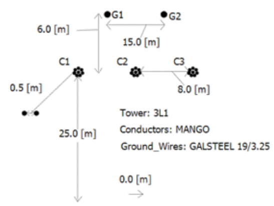
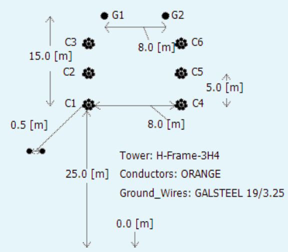
- Conversion of PI lines to Bergeron line models, where network impedances and case timestep allowed.
- Loads were converted using a ZIP model, with Np = 1.0 and Nq = 3.0 (typical figures used in the mainland NEM).
- Transformers were translated without approximation of saturation enabled (however this can be readily enabled within PSCAD™ if needed).

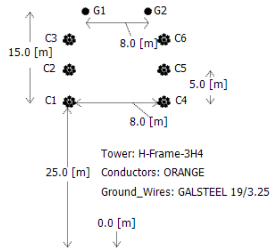
With the component modelling detailed further on, this allowed for immediate use of a NEM-like system for analysis.

New network lines

Additional network lines were constructed by developing a set of common line parameters based on geometrical line modelling in PSCAD, using the assumptions on physical configurations shown in Table 3. Tower and bundling arrangements were chosen based on a mixture of researcher knowledge of common configurations used in the mainland NEM, along with sampling common configurations based on images from Google Maps Street View.

Table 3 New transmission lines configurations

Type	Conductor	Tower Dimensions	Image
500 kV	Mango* Quad-bundled	Height: 70m total Lowest conductor: 30m Horizontal spacing: 25m Vertical-stacked arrangement	
330 kV	Mango* Dual-bundled	Height: 31m total Lowest conductor: 25m Horizontal spacing: 8m Horizontal arrangement	
275 kV	Orange* Dual-bundled	Height: 40m total Lowest conductor: 25m Horizontal spacing: 8m Vertical-stacked arrangement	

Type	Conductor	Tower Dimensions	Image
220 kV	Orange* Single conductor	Height: 40m total Lowest conductor: 25m Horizontal spacing: 8m Vertical-stacked arrangement	

* as defined in the Nexans Overhead Line Catalogue [18].

Furthermore, line lengths were determined using distance measurements on open maps such as Google Maps, assuming circuits follow the most direct route, avoiding major obstacles such as mountains and bodies of water.

Extra high voltage lines (e.g., 500 kV lines) of appreciable length were assumed to be shunt-compensated to avoid the excessive overvoltages that may be otherwise experienced when lightly loaded, unless explicitly not shown by the public project plans (e.g. some portions of PEC).

Combining these elements, this allowed the generation of equivalent PI-section models based on the resistance, reactance and susceptance calculations of the line types, which can then be scaled depending on the line length. Although differences in design choices and route options mean that these circuits are unlikely to precisely match the ultimate circuit built, they are expected to be not too dissimilar and can help provide the necessary insight for the scenarios developed.

In total, 27 new transmission line variants and 50 new instances were added into the cases.

New network transformers

New network transformers were assumed to have a similar value to those already in the case, which is approximately 10% impedance on the MVA base of the device. MVA bases were chosen based on the voltage level and nearby new plant expected to connect, typically in the range of 200 MVA for lower network voltages to 1000 MVA for connections nearby to new major REZs.

A basic hysteresis model was included in the transformers, and winding configurations were grounded Y-Y which match both the previous models in the original case, and from a zero-sequence perspective, are similar to autotransformers commonly used across the high-voltage network.

In total, more than 27 new network transformers were added into the cases.

Future network model development assumptions (2027, 2030, 2034)

The following principles were used to develop evolutionary models of the base 2024 model.

- The network model will be grown from the University of Adelaide 14-generator, 59-bus model topology to accommodate projects identified as actionable in the 2024 Final AEMO ISP.
  - All the cautions and notices provided by this original model's developers therefore apply in this work.
- Generator closures are based on the AEMO generator closure list published October 2024[3]. Subsequent updates to this list from October 2024 onwards will not be accommodated in the work.
- Major load centres will not change location, and large industrial loads are not explicitly modelled.
- Information on individual network projects is sourced from public documents such as transmission annual planning reports [3] [4] [5] [6] and project websites [7] [8] [9] [10] [11] [12] as they exist in 2024. Given the early stage for many such projects, they are highly subject to change.
- Where practicable, a representative bus for each major renewable energy zones noted in the AEMO ISP should be included in the model. Practicable in this context refers to:
  - An appropriate network corridor exists that can offtake the energy produced by the REZ, or
  - Sufficient public information exists regarding the new network connection to the remainder of the NEM, and
  - The REZ is of appreciable size (e.g., >1 GW) to warrant inclusion in a reduced-order model (see Table 13 for the REZs included in this analysis).
- Each REZ will be represented by an aggregate model, comprising a GFL Type-IV WTG model, a GFL solar farm, and a BESS.
  - The BESS may be in GFM or GFL mode, depending on the scenario being evaluated.
  - Proportions of these three technologies can vary depending on the geographical location, but as a starting point will be equal ratio of wind, solar and batteries.
  - As proportions of generation technologies in each REZ are currently unknown, it was assumed that there would be equal proportions of wind, solar and BESS in each REZ.
- Each REZ will conform to the automatic access standard for point-of-connection voltage and frequency protection.
- Not every REZ will be online simultaneously (and to aid EMT simulation burden, shouldn't be).

[3] Available at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

- Synchronous plant that have retired by 2034 may be converted into a synchronous condenser if there is a need for voltage support in the area.
  - Candidate plant were identified through owner public statements regarding their intention to convert their plant to synchronous condensers over time [19], or based on heavily interconnected nodes that support IBR equipment with specific fault current requirements (e.g., Loy Yang and Basslink).
- To aid in the replicability of this work, the number of EMT cases within a simulation set should not exceed 21, as beyond this value the simulation speed reduces markedly[4].

3.1.5 Component Modelling

Table 4 provides a summary of the models developed and/or used in this work.

Table 4 Summary of component models

Model	Sub-variants	Instances	Based on	Notes
Synchronous Generators	14	45	University of Adelaide data	
AVR	16	21	University of Adelaide data	Updated to more modern type. Includes sync-con AVRs.
PSS	14	14	University of Adelaide data	
OEL	14	14	Typical data as per IEEE 421.5	
UEL	14	14	Typical data as per IEEE 421.5	
Synchronous Condensers	2	7	Anonymised machine data	
Static VAR Compensators	3	8	PSCAD in-built example, University of Adelaide sizing data	Settings altered for weaker system & a simple low-voltage blocking mechanism added
UFLS relays	1	31	AEMO data	
REZ PNI interfaces	20	20	Original	Including initialisation aids
REZs	80	80	EPRI-provided dynamic models	Including low MVA and high MVA variants, GFL and GFM variants. Several modifications and adjustments made in conjunction with EPRI to aid in initialisation and case stability.
Voltage and frequency Protection relays	20	20	NER settings	
Additional transmission lines	27	54	As described previously in this section	
Total models developed	**225**	**328**		

[4] On the computing equipment used for this study.

Synchronous Machine Models

Disaggregation

For each synchronous machine model in the underlying PDT case, a disaggregated set of synchronous machines were created based on the approximate nameplate rating of each individual machine. This was based on information that was available in the public domain.

Example: The 14/59 model equivalent machine for Loy Yang was originally rated at 4667 MVA. In reality, there are four Loy Yang A and two Loy Yang B machines, plus a collection of Valley Power peaking GTs. The Loy Yang machines are capable of outputting close to 600 MW each, hence the 4667 MVA aggregate was divided into 7 equally sized machines at 666 MVA/machine (i.e., 600 MW @ 0.9 pf), to represent the six large Loy Yang turbines, plus an equivalent representation of the Valley Power peaking GTs.

The precise number and size of machines disaggregated are approximate, and although efforts were made to match sizing and unit numbers wherever possible, it was not always achievable. This does not impact on the outcomes of the studies however, as the intent is to consider approximate impact of online synchronous machine MVA on general IBR performance, rather than evaluate the performance of any one specific synchronous machine.

Generator modelling

EMT generator models were parameterised based on the above sizing and the dynamic parameters provided in the original 14/59 bus model. It is important to note:

- Generator saturation profiles are not included in this data.
- It was found that PRSIM™ did not consistently translate data from a PDT dynamic file into a PSCAD™ EMT model, and hence, the models were translated manually.

AVR, Stabilisers, and Limiters

The original 14/59 model provided a basic AVR parameterisation for each aggregate synchronous machine, however the assumption was that most round-rotor machines use a static excitation model of ST1A, and most salient pole machines use an AC excitation model of AC1A. Although this may have been a valid assumption at the time of model development, the Stage 4 researchers are aware that most large synchronous machines used in the system are using a relatively modern ABB-branded AC excitation system. As such, the EMT AVR models were switched to the more modern ST1C and AC1C models, as per the specifications in the IEEE 421.5-2016 standard for newer ABB AVRs. In most cases, the parameters were directly translatable from a xx1A to a xx1C variant. The default PSCAD™ library component[5] was used.

The stabilisers provided in the original 14/59 model were the IEEEST variety, and these were kept unaltered in the EMT model developed. An E-TRAN redistributable library component was used to represent this stabiliser. Note that a sensitivity study was completed with and without the stabilisers in service, and it was noted that the EMT model showed poor damping across the NEM with the stabilisers switched out of service, and strong damping with the stabilisers in service. This gives confidence that the stabilisers remain fit for purpose in the current model incarnation.

There were no under-excitation limiters (UEL) or over-excitation limiters (OEL) provided within the original 14/59 model; hence they were created to better represent the limiters likely to be activated in the studies of interest in this work. Given the above use of the ST1C and the AC1C AVR models, mating limiter components were chosen, being the OEL2C for the OEL and UEL2C for the UEL. The topologies for these components were developed based on the block diagrams provided in the IEEE 421.5-2016 standard, along with technology-appropriate default parameters provided within the same standard. Individual machine testing was completed to confirm correct operation of these limiters prior to integrating the synchronous machine model into the wide-area case.

Governors

Given the extensive efforts of previous Topic 6 researchers in the frequency control space, the scope of this Stage 4 work does not seek to consider frequency control effects in its analysis and instead focuses on “fast” power system phenomena related to system strength, transient voltage control and fault current provision. As such, there are no governor models developed for the synchronous machines present in the case.

However, in the cases where synchronous machines still provide substantial frequency correction services, a simple PI controller has been included on several larger synchronous machines to ensure that the simulation returns to a 50.00 Hz target value following a disturbance (where possible). Notably, this is intentionally a slow PI controller so that it does not materially interfere with the fast dynamic performance of the system which is being studied. This is a simulation convenience only and is not intended to be reflective of any real governor action.

[5] It is worth noting that during the course of this development, a material bug was found in the PSCAD™ master library component for AVRs, which caused irrational behaviour of other unrelated components in a wide-area case, based on their physical location on the canvas. The developers of PSCAD™ were made aware, and rapidly developed a new library component, which has been included in the latest update patch for PSCAD™.

Synchronous Condensers

Models for existing synchronous condensers in the NEM were included in the wide-area model. These were parameterised on anonymised data available for similarly sized synchronous machines and associated AVRs. With an intent to investigate the worst-case scenario of no damping being provided by synchronous condensers (a common but increasingly resolvable problem in reality), no stabilisers were included in the synchronous condenser models. Hence, it is possible that the oscillatory response of the synchronous condensers included may be exaggerated compared to those installed in the field.

Note that the conversion of synchronous generators to synchronous condensers was achieved by removing the governor model of the existing unit from service, and allowing the synchronous machine to run as a motor.

A note on synchronous machine initialisation

The Stage 4 researchers would like to highlight that the most effective and consistent method found to initialise synchronous machines such that they flat-start is simply to match the terminal voltage magnitude and terminal voltage phase within the synchronous machine model, as shown in Figure 3.

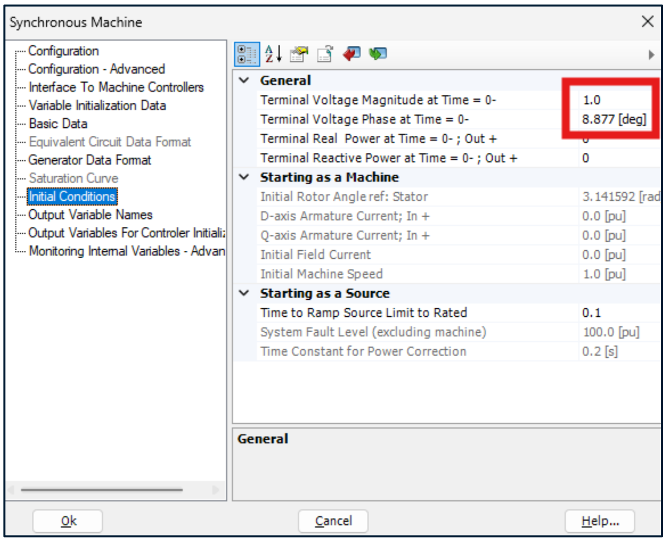


Figure 3 Recommended settings to adjust for initialisation

It was found that other available methods (such as other initialisation fields within the model or even dedicated external initialisation programs) did not yield as reliable results as simply setting the fields highlighted above to match the values calculated in load-flow.

Static VAR Compensators

The SVCs in the case were a modified version of the SVC models included within the PSCAD Example Library. These devices were altered as follows:

- Sizing of each device according to the original University of Adelaide model.

- Adjustment of the main control loop bidirectionality of the device, allowing both inductive and reactive behaviour.
- Inclusion of a freeze function, which ceases reactive support when the RMS terminal voltage drops below 0.7 pu and only re-enables functionality when the voltage returns above 0.8 pu as shown in Figure 4.
- Adjustments of the PI controller gains for SVCs located in low system strength regions (e.g., far north Queensland REZs).

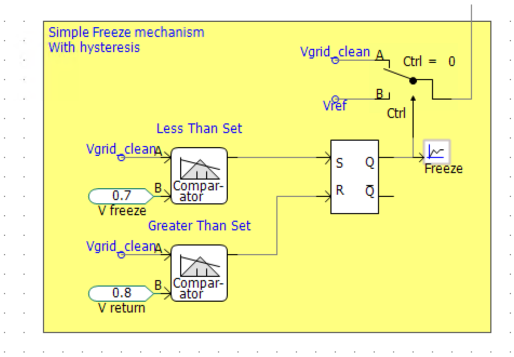


Figure 4 Simple SVC voltage freezing mechanism

IBR Generator Models

Generic Wind Turbines

A generic Type IV wind turbine model was obtained through the PSCAD™ Knowledge Base repository[6]. Once several key adjustments were made, this model was used across all cases where a wind turbine performance is considered. A Type IV wind-turbine was chosen as the majority of OEMs in the NEM seem to favour this technology over Type III devices. This is not to say that there is anything inherently inferior with Type III turbines, only that Type IV turbines seem to be more common in NEM installations.

Several modifications were required to this model to allow correct operation in the cases developed. Aside from converting operation from 60 Hz to 50 Hz, the original model works on an assumption that active power output can be scaled either based on the number of turbines set in service (through a current scaling device), and each turbine would initialise at maximum output power. In reality however, and especially when considering fast controller stability phenomena in weak grids, there is likely to be most (if not all) turbines in a wind farm online simultaneously but curtailed in its output either due to low wind speed or an active dispatch curtailment applied to the plant. That is, the connected MVA is high, but the exported MW is low. To be able to accommodate this arrangement, modifications were made to the model's pitch-control mechanism to allow an initialisation of the aggregate

[6] Available at: https://www.pscad.com/knowledge-base/article/227

turbine at a value below its maximum output. This predominantly consisted of the ability to set a pitch controller integral reset value based on a lookup table which was parameterised heuristically, and the inclusion of a variable active power setpoint. This modification is shown in Figure 5.

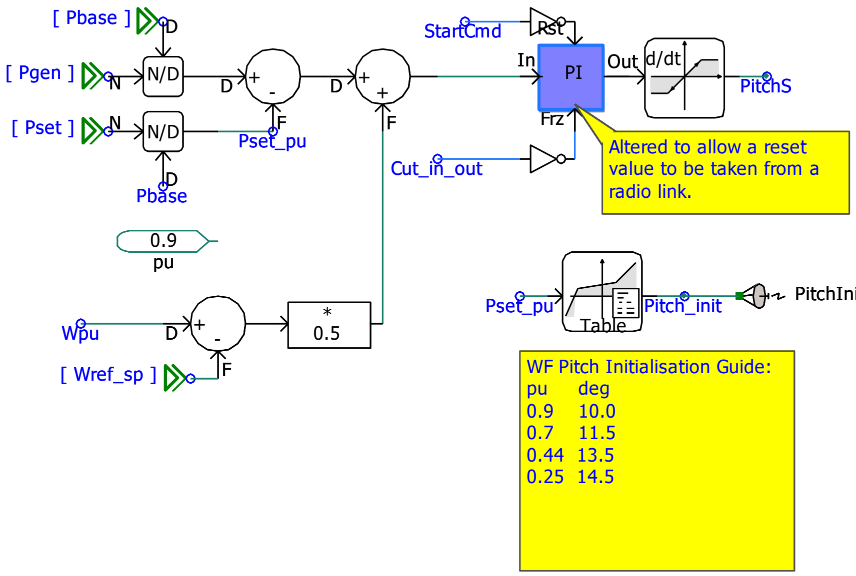


Figure 5 Modifications within the WindTurbine_Mechanical Block

The operational mode of the turbines was set to Q-priority, MV terminal voltage control with no frequency sensitivity.

Generic Battery Model

A hybrid solar-battery model was provided by EPRI. The model contained separable components for the battery, the solar PV and the park controller module. It was decided to operate the solar and battery components separately, rather than under the control of a single park controller module, as the park controller was designed for a different purpose, and separate control of solar and BESS may better represent a situation in a REZ with multiple parties operating without coordination.

The battery module can be switched to operate in a variety of synchronising modes, including:

- Grid following (based on SRF-PLL)
- Grid forming – Droop
- Grid forming – Virtual Synchronous Machine
- Grid forming – Virtual Oscillator

The battery has a variety of additional features such as:

- Direct-Q, Direct-V or voltage droop modes
- Frequency droop
- K-factor or NPS injection modes

- P or Q priority

All controller settings and structures are open and adjustable to the end user.

For the purpose of these studies, the battery was set to:

- Droop mode for GFM variants, SRF-PLL for GFL variants.
- Voltage droop control (measured at terminals) (4%)
- Frequency droop control (4%)

Note that the negative phase sequence injection mode was not used in these studies, as to intentionally observe the effect of K-factor based current injection methods.

This model will be available to the research community through EPRI directly and is not included in the releasable models generated by Etik Energy as part of this Stage 4 work.

Generic Solar Model

Like the battery module, the solar module was sourced from the hybrid model provided by EPRI.

The solar module is a grid-following only type, with a full representation of AC and DC-side controllers, open settings, and a variety of GFL synchronisation modes (DSOGI was chosen for the studies completed). It has a fault ride-through mode, allowing additional current injection for these events similar to the majority of real solar plants on the market.

This module was predominantly used for later-year studies in REZs and was kept in a constant P & Q control mode, allowing other modules (wind and BESS) to respond to voltage and frequency variations.

This model is available to the research community through EPRI directly[7] and is not included in the releasable models generated by Etik Energy as part of this Stage 4 work.

Pumped Hydro Model

Pumped hydro generator models were not available for use in this work. Instead, and noting this is not a direct replacement by any means, wind-turbine models were used in place of a pumped hydro model. This is because pumped hydro technology shares some similarities with wind turbine technology.

Future research should replace these models with better representation of pumped hydro models.

[7] Available at: https://www.epri.com/research/products/000000003002025889

Generic Generator Protection Relays

Where a plant model did not include any form of generating unit protection, a generic protection scheme was applied to the plant's point of connection to emulate basic tripping behaviour expected in the NEM. The generic model considered the following aspects:

- Voltage protection (evaluated at the PoC) in line with the Automatic Access Standard (AAS) described in NER S5.2.5.4 (a), recreated in Figure 6.
- Frequency protection in line with the Automatic Access Standard (AAS) described in NER S5.2.5.3 (b), recreated in Figure 7, noting that the measurement of rate of change of frequency (RoCoF) is an imprecise and open area to consider how this should be best evaluated.

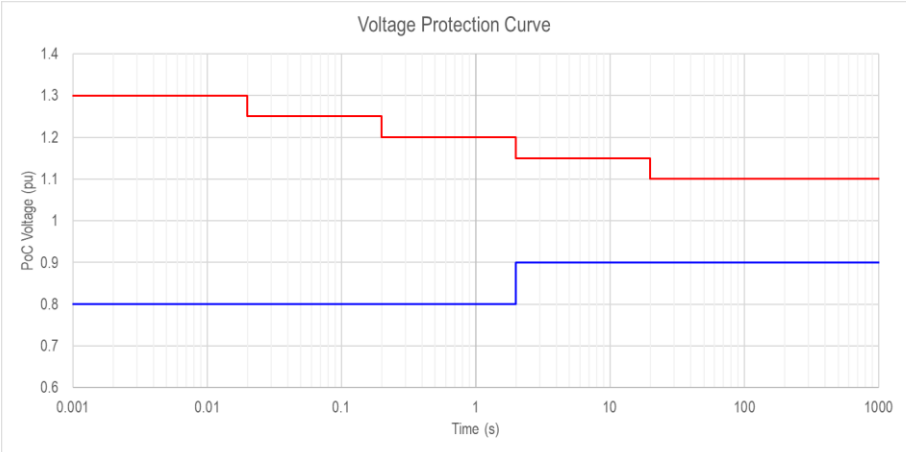


Figure 6 Voltage withstand requirements of the NER AAS

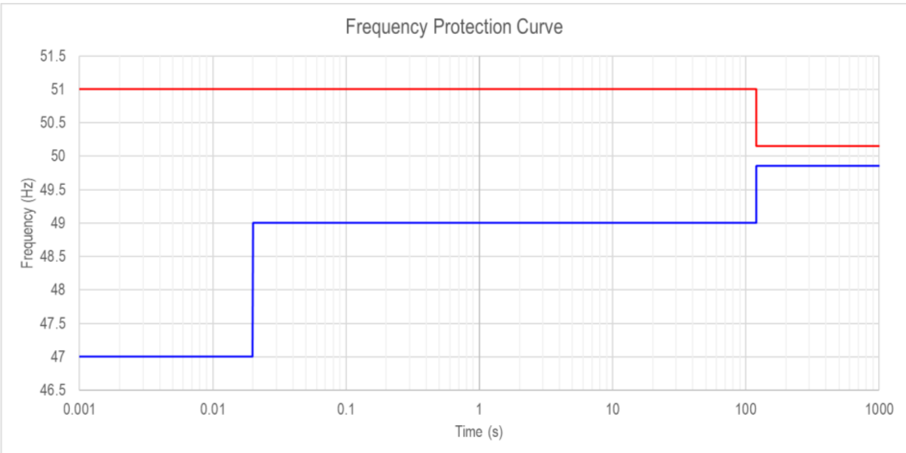


Figure 7 Absolute frequency withstand requirements of the NER AAS

Once protection is activated for any of the criteria is trigger, the plant will be tripped at its point of connection for the remainder of the simulation run.

Voltage measurements were completed by comparator evaluation of simple RMS 'multimeter' measurements, however frequency measurements were taken using a PLL to track system frequency. This is because:

- FFT blocks are slow to respond to changes and have a propensity to irrecoverably lose frequency tracking for some voltage waveforms with distorted waveforms.
- Filtered zero-crossing detection often results in wild swings in frequency (e.g., in the order of tens of Hertz) during fault periods.

Illustrating this point is Figure 8 below, showing three different common methods for measuring frequency in EMT, resulting in very different readings. The PLL frequency calculation is closest to the real system frequency for this event.

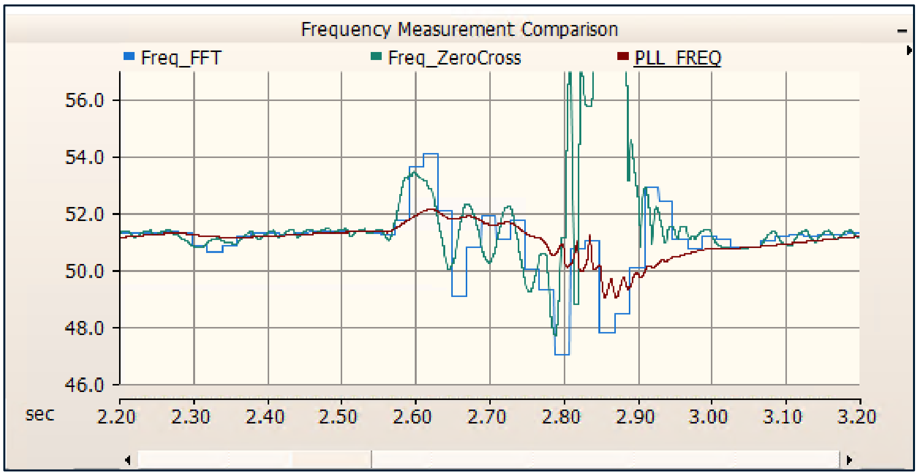


Figure 8 Frequency measurement differences during periods of high voltage waveform distortion

Bulk load models

Bulk load models followed the convention that AEMO currently uses in wide-area EMT studies whereby active power sensitivity to voltage has an exponent of 1 (Np=1.0), reactive power sensitivity to voltage as an exponent of 3 (Nq=3.0), and load relief is set to 0.5%.

UFLS models

Although system frequency performance was not a focus of this work, underfrequency load-shedding models were developed and included in the case. These are predominantly expected to be used for islanding scenarios, where the supply-demand balance could be disrupted causing a frequency collapse that would need to be arrested. The inclusion of UFLS relays to shed load where necessary allowed the focus to remain on the fast dynamics of the devices in the case without causing a case collapse due to frequency imbalance.

The thresholds for the UFLS relays were developed based on an extrapolation of previously published AEMO data[8] which required load shedding to commence once the frequency dropped below 49.0 Hz, and to reach a maximum of 30% load shed by the time 47.5 Hz is reached. The result is the profile shown in Figure 9.

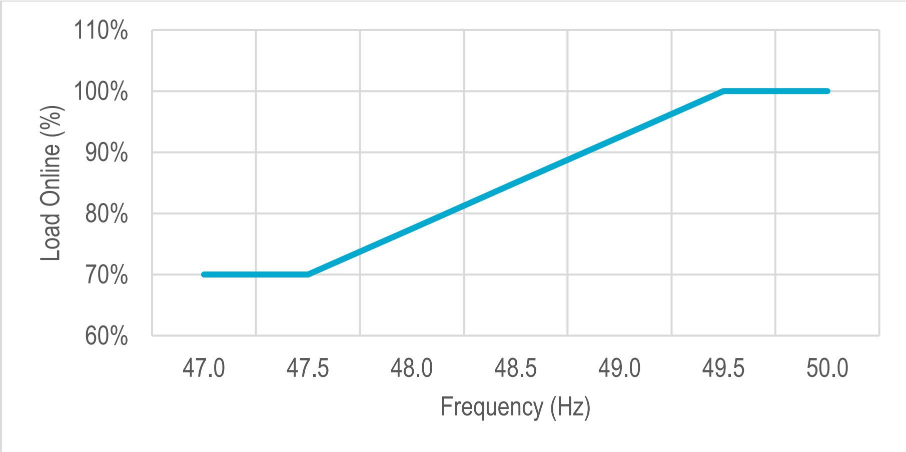


Figure 9 UFLS load reduction curve

3.2 Analysis

The following outlines the approaches used to establish scenarios for evaluation, and the approaches used to evaluate the output of these scenarios.

3.2.1 Prioritisation

In developing the research roadmap, it was acknowledged that previous efforts primarily focused on frequency control and inertia. While these remain critical, a more comprehensive review of all factors contributing to overall system security was deemed necessary. This includes examining various aspects of system stability, system strength, and their relationships with power system protection and power quality.

As a result, the decision was made to prioritise investigating system needs related to faster phenomena, particularly those occurring within a few cycles, such as responses during faults and after fault clearance, specifically fault current magnitude, fault current sequence, fast voltage control, synchronising power, and phase angle jump suppression.

This is because there is less certainty in the industry surrounding the very fast transient space regarding how the power system must be supported to maximise the ability for IBRs

[8] Available at: https://aemo.com.au/-/media/files/initiatives/der/2021/south-australian-ufls-dynamic-arming.pdf Figure 14 used, with an assumption that for approximately 3000 MW peak load, 1000 MW (~30%) would be shed by the time 47.5 Hz is reached. This was used for the whole mainland NEM case.

to remain online. This is also consistent with the type of phenomena experienced recently based on real system incidents in practical power systems in Australia and globally. It was also recognised that these types of phenomena often require more detailed power system modelling, with a particular emphasis on EMT simulations.

3.2.2 Case input development

Minimum demand scenarios consider:

- Reduced number of synchronous machines online, lowering the stiffness of the power system and increasing the propensity for fast inverter controllers to lose synchronism with the grid.
- Low damping from the network loads, potentially leading to more oscillatory behaviour and exposing underlying system resonances.
- High network voltages, which may necessitate the removal of high-voltage lines from service to alleviate line charging.
- Synchronous machines operating with low field current, potentially leading to more oscillatory behaviour.
- An inability for synchronous machines to aid in sustained overfrequency scenarios due to already operating at their minimum active power.
- Reduced or zero headroom available in network reactive compensation devices, altering during-fault and post-fault responses.

Maximum demand scenarios consider:

- Lower system voltages and greater propensity for voltage collapse across the system for contingencies.
- Reduced or zero headroom available in network reactive compensation devices, altering during-fault and post-fault responses and further increasing the potential for voltage collapse.
- Single generator contingencies potentially causing large shifts in system operating points.
- Increased sensitivity of load to changes in network voltage.
- An inability for synchronous machines to aid in sustained underfrequency scenarios due to already operating at their maximum active power.
- Increased number of synchronous machines online, increasing the stiffness of the power system and reducing the propensity for fast inverter controllers to lose synchronism with the grid.

2024 Dispatch Scenarios

The updated 14/59 model had several generator and load dispatch scenarios developed, such that sensitivities to demand and generation type could be evaluated. Specifically, the scenarios in Table 5 were created. Full details of generator dispatch are available in the files referenced in Appendix C .

Table 5 2024 NEM Dispatch Scenario Targets

Variant	NEM Total Loading	Synchronous Dispatch	GFL IBR Dispatch
A	8 GW	Medium	Medium
B	8 GW	Minimal	High
C	30+ GW	High	Low
D	30+ GW	Medium	Medium

Note that:

- Generators were not dispatched to their absolute maximums. The GVA of dispatched generators was kept at 150% of the GW they are supplying (e.g., an 8GW demand has 12GVA of generation dispatched).
  - This is because the NEM is always operated in such a way that there is headroom to cater for the loss of generation sources and network constraints following disturbances.
- GFL-based IBR devices were only considered in 2024, as GFL currently dominates the IBR technology operating in the NEM today.
- 8 GW approaches the minimum loading seen in the NEM, while 30-36 GW approaches the maximum loading seen in the NEM – although the latter may be impractical to implement in a simplified model due the absence of sufficiently meshed network to prevent voltage collapse.
- High dispatch of IBR for a peak demand case is not currently practical today, as synchronous plants are still crucial for supplying energy for maximum demand scenarios.

2027-2034 Dispatch Scenarios

The following scenarios were created for each of the temporal iterations of the cases. Full details of generator dispatch are available in the files referenced in Appendix C . Note that high synchronous machine dispatch scenarios were not investigated as this has well understood performance.

Table 6 2027 to 2034 NEM Dispatch Scenario Targets

Variant	NEM Total Loading	Synchronous Dispatch	GFL IBR Dispatch
A	8 GW	Minimal	Medium
B	8 GW	None	High
C	36 GW	Moderate	Moderate
D	36 GW	None	High

Fault conditions

Aimed to fault and trip the same line that is likely to have a strong impact all cases, from 2024 to 2034.

Note that this is not necessarily the highest loaded line in each case, as this will change from dispatch to dispatch, but in general is a line that would be expected to have an appreciable flow and/or cause a major disturbance to the IBR devices in the system across all scenarios studied. These lines were determined to be as follows.

Table 7 Line fault locations

Location	Line	Fault
Victoria	Loy Yang to South Morang 500 kV	LLG fault cleared in 60/80ms at South Morang
New South Wales	Wollar to Mt. Piper 500 kV line	LLG fault cleared in 60/80ms at Wollar
Queensland	Tarong to Callide 275 kV line	LLG fault cleared in 120/250ms at Tarong
South Australia	Robertstown to Para 275 kV line	LLG fault cleared in 120/250ms at Robertstown

For cases that considered the islanding of a region, the following fault in Table 8 was applied. Fault clearance times are based on primary clearance times specified for the given voltage level in the NER.

Note that it was determined with the introduction of Project Energy Connect, South Australia has multiple AC interconnections, and it is unlikely to island as easily as it has in the past. Instead, the Queensland region was chosen to be the focus of islanding studies, whereby all circuits of QNI were tripped.

Table 8 Islanding fault location

Location	Line	Fault
Queensland	Dumaresq to Bulli Creek 330 kV line	LLG fault cleared in 120/250ms at Bulli Creek

List of REZs included in the cases

The following table outlines the REZs considered in the developed cases and their generation proportions. Note that deviations from the base assumption of ⅓ each of BESS, wind and solar were made based on known project inclusions (e.g., Torrens & Waratah Super BESS), obvious geographical limitations for hosting a given technology type (e.g., Snowy 2.0 in mountainous regions precluding solar), or obvious trends from the AEMO generation maps [20] for the given area.

Table 9 List of REZs

REZ	Region	Generator Proportions
Copperstring	Queensland	⅓ BESS, ⅓ Wind, ⅓ Solar
Callide (Q9)	Queensland	⅓ BESS, ⅓ Wind, ⅓ Solar
Gladstone (Q6)	Queensland	½ BESS, ½ Solar
Braemar (Q8)	Queensland	⅓ BESS, ⅓ Wind, ⅓ Solar
Woolooga	Queensland	⅓ BESS, ⅓ Wind, ⅓ Solar
New England / Armidale	New South Wales	⅓ BESS, ⅓ Wind, ⅓ Solar
Eraring / Waratah Super BESS	New South Wales	BESS only
Western NSW	New South Wales	⅓ BESS, ⅓ Wind, ⅓ Solar

REZ	Region	Generator Proportions
Hunter	New South Wales	⅓ BESS, ⅓ Wind, ⅓ Solar
Tablelands	New South Wales	⅓ BESS, ⅓ Wind, ⅓ Solar
Snowy 2.0	New South Wales	½ BESS, ½ Wind
South-West NSW	New South Wales	⅓ BESS, ⅓ Wind, ⅓ Solar
Central-North	Victoria	⅓ BESS, ⅓ Wind, ⅓ Solar
Gippsland	Victoria	⅓ BESS, ⅓ Wind, ⅓ Solar
West Murray	Victoria	⅓ BESS, ⅓ Wind, ⅓ Solar
Victoria Big Battery & Surrounds	Victoria	⅓ BESS, ⅓ Wind, ⅓ Solar
South-West VIC	Victoria	⅓ BESS, ⅓ Wind, ⅓ Solar
Robertstown (S2, S3)	South Australia	⅓ BESS, ⅓ Wind, ⅓ Solar
Davenport (S5, S6, S7, S8, S9)	South Australia	⅓ BESS, ⅓ Wind, ⅓ Solar
Torrens BESS	South Australia	BESS only

List of key measurement nodes

Table 10 shows the network nodes which were measured throughout all simulations. A limited set were chosen due to their high interconnectivity or proximity to the remainder of the network, proximity to major load centres, and where measurements for generators were generally distant from this location. Voltage, frequency and phase angle were recorded for each.

Table 10 Network measurement nodes

Node	Region
Armidale 330 kV	New South Wales
Buronga 330 kV	New South Wales
Heywood 275 kV	Victoria
Nebo 275 kV	Queensland
Para 275 kV	South Australia
Ross 275 kV	Queensland
Rowville 220 kV	Victoria
South Morang 500 kV	Victoria
South Pine 275 kV	Queensland
Sydney West 330 kV	New South Wales
Yass-Canberra 330 kV	New South Wales

3.2.3 Case output analysis

Evaluation of the power system's technical performance and subsequent needs to maintain stability is a nuanced matter, with currently many open questions when it comes to inverter-dominated systems.

It is generally accepted in the industry that inverter-dominated systems are best analysed in the planning timeframe through the use of Electromagnetic Transient simulations, i.e., time-domain simulations. Although several metrics can be used to evaluate the performance of such a system, the sheer scale and complexity of these simulations can make it difficult to have a full picture of system performance. This is because:

- The simulation setup and computation burden are such that running exhaustive sets of studies covering all operating modes and scenarios is seldom practical, and that inferences must be drawn from a limited set of studies, usually at the extremes of expected scenarios.
- Observation and analysis of every possible inverter internal quantity is impractical (there may be hundreds of channels to consider per device), although some key stability insights can be gleamed from commonly available internal metrics (e.g., PLL frequency tracking or Id/Iq references).

Noting the above, analysis of the results generated in this work were a combination of qualitative observations based on the researchers' extensive experience in this space, along with quantitative measurements of critical qualities relating to the work to be analysed in Stage 4.

Quantitative analysis

The following metrics were calculated from measurable quantities in simulation for Stage 4 priorities.

Table 11 Quantitative metrics

Quantity	Why
Protection operation	Outside of protection of an asset under fault, a grid scenario that results in network conditions such that additional protection relays must operate to protect plant, or the network itself is an indicator that the system is not robust and/or stable.
Network voltage depression times	Extended voltage depression times during or following disturbances can be indicative of insufficient reactive power support in the system or a loss of synchronism between regions[9]. Generally, it is expected that voltage should recover to pre-fault levels very soon after fault clearance.
Network overvoltage magnitude	Following the clearance of a fault (or potentially even during a fault event), transient overvoltages may occur with the potential to trip nearby equipment. Understanding if particular generation types or profiles tend to produce overvoltages is an important insight.

[9] Not exclusively, but it is a characteristic of loss of synchronism.

Quantity	Why
Fault current waveform peak	Peak waveform current values are important for fault discrimination by protection relays and for the triggering of simple downstream protection mechanisms (e.g. fuses).
Fault current RMS peak	Peak RMS current values are important for fault discrimination by protection relays and for the triggering of simple downstream protection mechanisms (e.g. fuses).
Fault current negative to positive sequence ratio	Unbalanced fault current provision is an important quality of the power system to prevent overvoltages on healthy phases, yet it is known to be a potential deficiency in a system comprising predominantly of inverter-based resources.
Frequency recovery value	Frequency recovering to a stable value within a region is an indicator of adequate frequency control and both positive and negative headroom of generators in a system.
UFLS activation	UFLS activation is an indicator that insufficient frequency control and/or inertia is present in a system.
Phase angle shifts	Comparing pre- and post-disturbance phase angle shifts for a generator, along with the spread of shifts across the system can be an indicator of how stiff a response the unit is providing, and how decoupled the system is from disturbances (respectively).
Interconnector swings	The transient flows on an interconnector can provide insights into how much a region is able to independently compensate for the disturbance, or how reliant it is on neighbouring regions to maintain system integrity.

Qualitative analysis

The following metrics were evaluated from simulation output quantities for Stage 4 priorities.

Table 12 Qualitative metrics

Quantity	Why
Power injection profile during disturbance	During a disturbance, the commencement time, injection amount, consistency of delivery, and cessation time can provide both an insight into the stability of a devices participating in the event, and their ability to rapidly return the system to equilibrium.
Power swings post disturbance clearance (damping)	Following clearance of a fault, the system and its components will attempt to find a new equilibrium. In doing so, there may be an exchange of active and reactive power across the system, which may result in voltage and frequency excursions, or even excite instabilities which trigger further events. Assessing how controlled these swings are (swing magnitudes and their ability to decay within a set timeframe) gives insight into the stability of the system.
Inverter fast controller outputs	Where an inverter has lost stability in a system, it can be useful to understand whether the root cause was a fast inner controller instability issue (potentially indicating a system strength problem), or a more conventional controller instability issue. Inverter internal references for frequency tracking and current references are a strong indicator of such system strength stability problems.

4 Results

4.1 Roadmap Refresh (Milestone 1)

Following the production of the original Topic 6 research roadmap [21] and several rounds of research, it was decided that a refresh would benefit the overall direction of Topic 6 due to the rapidly evolving power system situation.

This review provides a detailed analysis of future system services in an inverter-dominated power system, focusing on fast-response and dynamically impactful services. It categorises services across multiple dimensions, including system dynamics, power quality, protection, restoration, and various constituting components of system strength. It leverages findings from numerous studies [22] [23] [24] [25] [26] [27] [28] [29] [30] [31] [32] [33] [34] [35] [36] [37] [38] conducted regarding the transition to an IBR-dominant energy system.

A summary diagram of the findings is presented in Figure 10, with the full unabridged table available in Appendix A

Classification of system services

The proposed roadmap categorises services into various domains:

- Balancing services, including frequency containment, restoration, and replacement reserves.
- Voltage control and reactive power management, addressing challenges such as voltage collapse, over-voltage management, and quasi-static voltage unbalance mitigation.
- Protection-related services, considering fault current characteristics (magnitude, sequence, and waveform).
- System restoration services, including self-energisation and extended islanding operation.
- Emergency response mechanisms, such as fast load and generation reduction.
- Power quality considerations, such as harmonic suppression, flicker mitigation, and rapid voltage change control.
- Stability-related services, covering synchronising power, oscillation damping, inertia, and RoCoF suppression.
- Network utilisation and demand response services, assessing their impact on network operation and planning efficiency.

Note that although system strength is not explicitly mentioned, it is encompassed within various protection and stability-related services, as well as power quality considerations, including fault current characteristics, synchronising power, and rapid voltage control.

New considerations and phenomena in an inverter-dominated power system

The transition from a synchronous generator-dominated system to one where IBRs play a major role has introduced new system behaviours and stability phenomena that were either not relevant or had much less impact in traditional grids. This shift has created the need for new system services that were not necessary in the past. The following key differences are noted:

1. Current-limited nature of IBRs
   - Unlike synchronous machines, IBRs are current-limited, meaning they can increase current output during disturbances (e.g., faults, transient events) by a modest level, e.g. 20%.
   - This has major implications for protection schemes, system strength, and fault ride-through strategies, necessitating new approaches to managing system security.
2. Multi-service provision with limitations
   - IBRs can, in theory, provide multiple services (e.g., fast frequency response (FFR), system strength, synthetic inertia, and oscillation damping), often with greater flexibility than synchronous machines.
   - However, they cannot provide all services simultaneously at their maximum capability. This creates trade-offs in service provision, requiring dynamic prioritisation based on system needs.
   - For example, a grid-forming inverter providing system strength may not simultaneously be able to deliver full frequency response or over-voltage suppression if operating near its current limit.
3. New stability concerns
   - Control interactions between multiple IBRs can create new resonance and oscillation issues, requiring services for damping sub-synchronous and super-synchronous oscillations.
   - The increasing interrelationship between system stability, power quality, and power system protection in inverter-dominated power systems will give rise to new, multi-dimensional phenomena that have traditionally been considered in a single-dimensional context.
4. Voltage and frequency coupling
   - As the system strength declines, active and reactive power controls become more and more interlinked, meaning that voltage changes can influence frequency stability and vice versa.
   - This requires co-optimised control strategies that balance voltage and frequency support without creating instability.

Implications for system services

- A greater number of services will be needed to address these emerging issues.
- Some of these services, such as oscillation damping and protection-related services, were not explicitly required in the past but will become critical in high-IBR grids.

- The power system will need near real-time service prioritisation, ensuring that the right service is delivered at the right time based on system conditions.

Delineation between system services and mandatory technical requirements

A critical distinction must be made between mandatory technical requirements under Generator Performance Standards (GPS) and system services which may require capabilities above and beyond what is required in the GPS. GPS compliance is a baseline requirement for generators connecting to Australia's National Electricity Market (NEM), whereas system services involve the provision of additional capabilities beyond these requirements.

Key principles for differentiation:

1. Compliance with GPS is not a system service
   - Under the current framework, GPS sets the minimum capability requirements for generators to connect and operate in the system.
   - However, even meeting the automatic access standards is not necessarily a service.
   - Example: A generator meeting fault ride-through requirements under GPS does not constitute the provision of a system service.
2. Capability vs. enablement of services
   - The framework distinguishes between:
     - Capability: The inherent ability of a generator to perform a function (e.g., frequency response).
     - Enablement: The activation of that capability in real-time for system needs.
   - Example: A generator may have the capability to provide FFR under GPS, but whether it is enabled and used in real-time is a system service.
3. Suppression vs. withstand capability
   - System services should focus on suppression of disturbances rather than just the ability to withstand them.
   - Example: A grid-forming inverter should not only withstand a voltage phase angle jump but also actively suppress and stabilise it, which could be defined as a service.
4. Criteria for defining a system service
   A system service is a function that goes beyond GPS compliance and meets one or more of the following conditions:
   - Operation outside GPS limits: Providing a response that is not required for normal compliance.
     - Example: A generator providing an active damping function to suppress a wide range of sub- and super-synchronous oscillations, which is well above and beyond what is required under the access standard framework.

- Adverse impact on energy market revenue: If providing the capability requires curtailing energy output or reducing market participation, it is considered a service.
    - Example: A battery maintaining headroom for synthetic inertia instead of maximising energy arbitrage.
- Adverse impact on asset lifetime: If providing the service accelerates wear and tear on the asset, it should be compensated as a service.
    - Example: Operating an inverter at its thermal limit to provide additional fault current beyond GPS requirements.
- Operational restrictions to maximise service provision: If an asset must be operated in a constrained mode to provide a capability, it qualifies as a service.
    - Example: A generator being dispatched at sub-optimal output levels to enable additional voltage control capabilities.

5. Non-network solutions as system services
    - Even where network solutions (e.g., synchronous condensers, transmission upgrades) exist, non-network alternatives (e.g., BESS, demand response, IBRs) can be considered system services if they provide a more cost-effective solution.
    - This aligns with the current regulatory framework, ensuring that both network and non-network solutions are assessed on an equal basis.

Implications for market design

As the grid transitions to a high-IBR system, market structures must evolve to accommodate new system services and ensure economic efficiency in their provision. The following considerations are essential:

1. Expansion of system service markets
    - Traditional ancillary service markets have focused on frequency and voltage control, but new services such as protection and stability-related services will require structured procurement mechanisms.
2. Co-optimisation of services and energy markets
    - Many new system services require trade-offs in energy market participation (e.g., a GFM battery reserving headroom for more effective provision of stability related services instead of providing energy arbitrage).
    - A co-optimised market structure can dynamically allocate resources to services based on real-time grid conditions.
    - Importantly, this co-optimisation should account for the roles of both transmission- and distribution-connected assets, including DERs and CERs, which increasingly participate in both energy and services provision. This reinforces the need for stronger coordination between market mechanisms and grid layers, as discussed in the following point. While a fully integrated co-optimisation across all these dimensions may not be feasible in the immediate term, advancements in the

modelling and performance of DERs and CERs will be key enablers for more comprehensive co-optimisation in the future.

3. TSO-DSO-End-user coordination for service procurement

- As distributed energy resources (DERs) play a greater role in system services, DSOs must be able to procure services from local resources while coordinating with TSOs to ensure system-wide efficiency. Note that the current work primarily focuses on transmission-related services. However, it will be beneficial to explore the interaction between the transmission and distribution systems, and role of end-users in future research.
- While the current work primarily focuses on transmission-level services, future efforts should explore integrated frameworks that enable coordinated procurement and dispatch of services across transmission and distribution systems, with explicit consideration of end-user impacts, constraints, and value propositions. Effective TSO–DSO–end-user coordination is essential to support co-optimised participation of resources in both energy and service markets. As noted above, a fully integrated co-optimisation may not be feasible in the immediate term; however, it remains the ultimate objective.

System strength and its role in inverter-dominated grids

System strength is inherently a multi-dimensional service that cannot be accurately narrowed down to a single phenomenon or system attribute. It spans multiple domains, including system stability, protection, and power quality, and involves various system attributes beyond just fault current contribution. Given this complexity, it is not appropriate to define a single overarching “system strength” service. Instead, it should be decomposed into several sub-categories, each representing a specific attribute that could be considered as a standalone service.

This distinction is particularly important as system strength services are expected to be sourced increasingly from IBRs rather than traditional synchronous machines. Unlike synchronous generators, which inherently provide system strength as a bundled capability, IBRs have technical limitations that prevent them from delivering multiple system strength attributes simultaneously. This necessitates a more granular approach to defining and procuring system strength services.

Key considerations for system strength as a service:

1. System Strength as a multi-attribute concept

- System strength affects various operational domains, including:
  - System stability (both small-signal and transient stability)
  - Network protection coordination (ensuring relays operate correctly)
  - Power quality (harmonics, resonance, and voltage fluctuations)

   - Defining it too broadly risks overlooking specific needs and challenges.

2. Breaking system strength into attribute-based services
   - Instead of a single "system strength" service, the following sub-category services should be considered:
     - Fault current contribution – Short-circuit level support to maintain network protection effectiveness.
     - Network impedance shaping – Managing variations in system impedance for improved stability.
     - Control interactions suppression – Avoid or suppress control interactions between several IBRs.
     - Small-signal stability support – Enhancing dynamic system performance under minor disturbances.
     - Protection system compatibility – Ensuring reliable relay operation as IBR share increases and the number of online synchronous machines declines.
     - Harmonic and resonance mitigation – Addressing power quality concerns due to widespread IBR penetration.
3. IBR-specific challenges in providing system strength services
   - Synchronous generators inherently provide multiple system strength attributes simultaneously (e.g., fault current, inertia, voltage control).
   - IBRs, due to their current limitations, cannot deliver all these capabilities in a bundled manner.
   - Future procurement and regulatory frameworks must unbundle system strength attributes to allow different technologies to provide them individually or in combination.

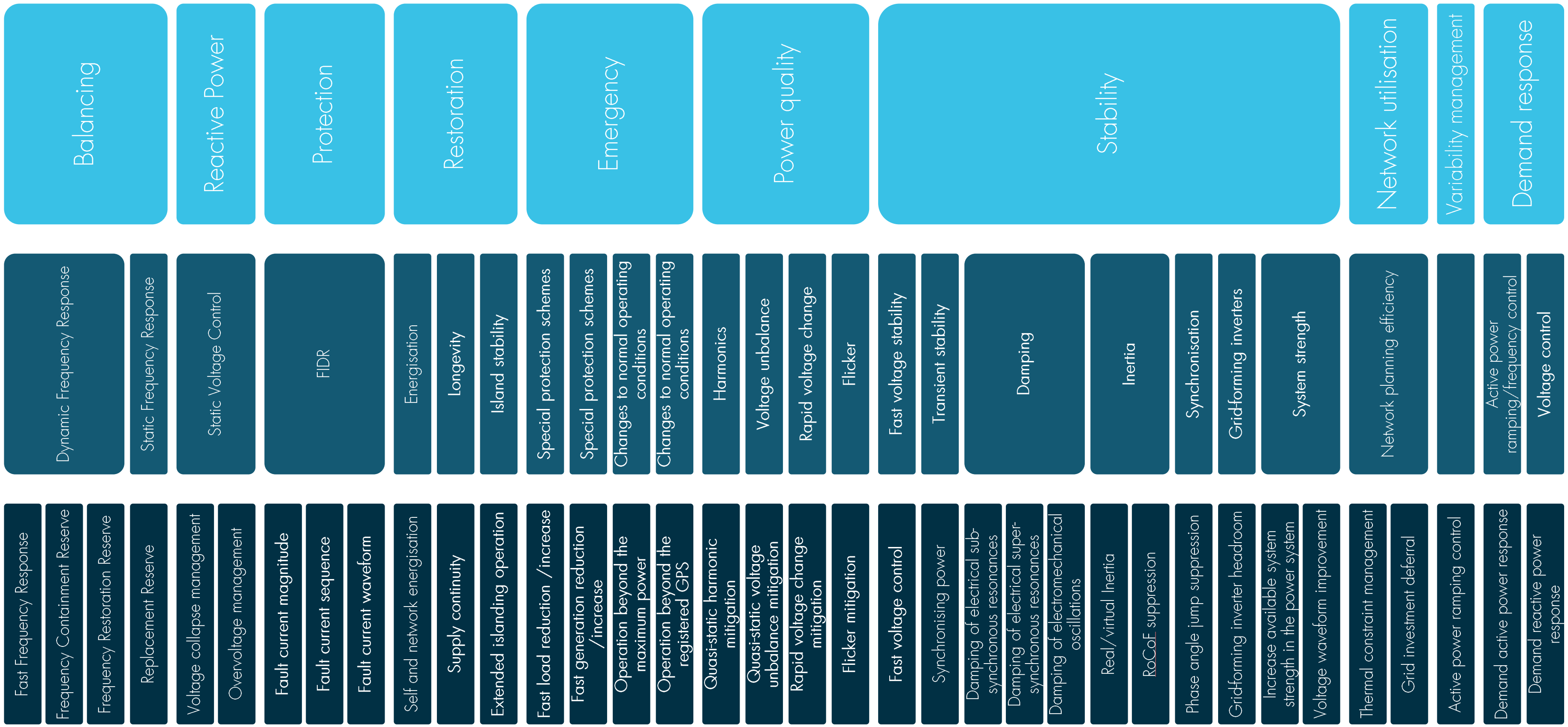


Figure 10 Roadmap Refresh Review of Important Power System Characteristics

4.1.1 Prioritisation

Given the previous researchers strong focus on balancing mechanisms and inertia, and the large number of potential areas for investigation, a decision was made to focus on the following faster-phenomena topics of power system performance for this research stage:

- Fault current magnitude;
- Fault current sequence;
- Fault current waveform;
- Fast voltage control;
- Synchronising power; and
- Phase angle jump suppression.

However, should there be any obvious need of the evolving system that appears, investigations and commentary will be provided (as was the case for increased need for fast overvoltage needs and fault current quality found in the analysis).

4.2 Evolution of the NEM (Milestone 2)

While this section predominantly covers the results from Milestone 2, it is logical to include the results of Milestone 3 (100% IBR) as a natural extension of the work. More information regarding the specifics of Milestone 3 is presented in the Section 4.3.

4.2.1 Milestone 2 Objectives

The purpose of this milestone was to establish a performance baseline of a reduced-order mainland NEM in 2024 and compare it to scenarios as the mainland NEM evolves from 2024 to 2034. The evolution was based on publicly available data detailing both generation retirements, REZ developments, and network improvements. In doing so, an evaluation can be made of how the technical needs of the NEM change over time, and what functions (or services) need to be provided by generators within the NEM to ensure a robust and stable system.

4.2.2 System network evolution steps

The following table summarises the major upcoming projects added to each network model as it evolved from 2024 to 2034, with case years highlighted in a red border.

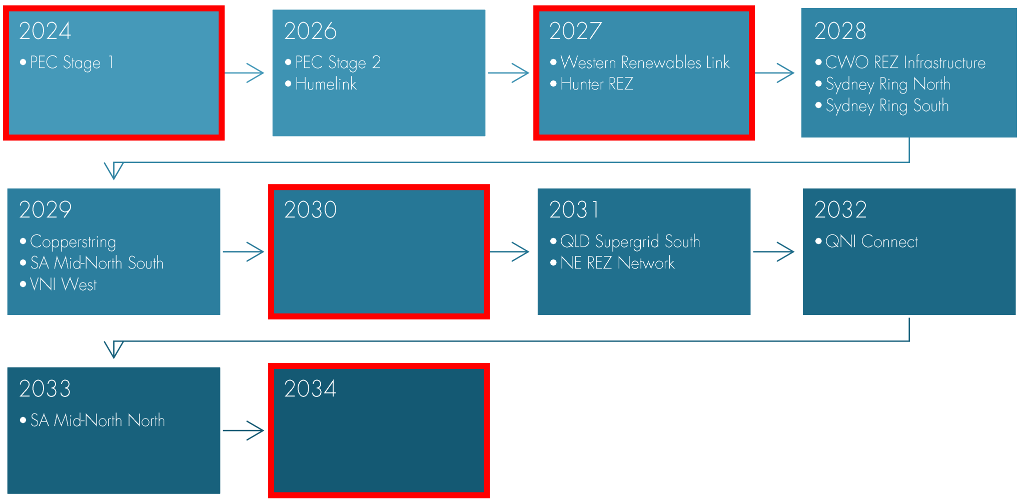


Figure 11 Transmission Changes by Year

Table 13 Changes to evolve the NEM representation over 10 years

Year	Transmission Changes	Generator Changes
2024	• Inclusion of the full existing 500 kV NSW network (Bannaby to Bayswater) • Removal of the existing 330 kV equivalent of the above 500 kV network • Inclusion of a 330 kV network between Bannaby and Yass-Canberra • Inclusion of the far-north Queensland REZ • Inclusion of PEC stage 1 (VIC to SA link) including synchronous condensers	• Removed Northern PS in South Australia • New GFL wind (Ross) and solar farm (Strathmore) within Far North Queensland REZ • Added the following REZs to represent existing large centres of IBR generation in the NEM: o Callide 275 (QLD) – Central region o Braemar 275 (QLD) – Darling Downs region o Armidale 330 (NSW) – New England region o Wollar 500 (NSW) – Western region & Central West Orana REZ o Yass 330 (NSW) – Tablelands region

Year	Transmission Changes	Generator Changes
	• Inclusion of a limited 220 kV representation of the West-Murray rhombus (VIC)	○ Dederang 330 (VIC) – Northern region ○ Loy Yang 500 (VIC) – Gippsland region ○ Red Cliffs 220 (VIC) – West-Murray region ○ Moorabool 500 (VIC) – South-west region ○ Heywood 500 (VIC/SA) – VIC SA border region ○ Robertstown 275 (SA) – East-mid-north region ○ Davenport 275 (SA) – Mid-north region • New BESS at Torrens Island 275 (SA) • Added synchronous condensers at Robertstown (SA), Davenport (SA), Buronga (NSW)
2027	• Inclusion of PEC stage 2 • Inclusion of Humelink • Inclusion of Western Renewables Link • Partial removal of West Murray rhombus (only Red Cliffs – Bulgana 220 remains)	• Inclusion of Dinawan Synchronous condensers • Removal of Torrens Island B • Removal of Eraring units • New REZ at Bayswater 330 (NSW) – Hunter region • New REZ at Dinawan 500 (NSW) – South-west region • Moved Armidale REZ 330 to Armidale REZ 500 (NSW) – New England REZ • Moved Red Cliffs REZ to Bulgana 500 (VIC) – West-Murray region
2030	• Inclusion of Sydney 500 kV ring north • Inclusion of Sydney 500 kV ring south • Inclusion of VNI West • Inclusion of Copperstring • Inclusion of SA Mid-North South upgrade • Reconfiguration of Yallourn to also connect to Loy Yang	• Inclusion of Snowy 2.0 REZ • Removal of Callide units • Removal of Yallourn units • Moved FNQ REZ representation (Ross & Strathmore) to end of Copperstring
2034	• Inclusion of NE REZ link • Inclusion of Queensland Supergrid South • Inclusion of QNI Connect • Inclusion of full SA Mid-North North upgrade	• Removal of Bayswater PS • Conversion of Vales Point to synchronous condensers*
* It was found that without additional voltage support in this area, cases were not viable, hence the decision to convert these units to synchronous condensers rather than removal altogether		

4.2.3 Results

Case stability summary

Table 14 summarises the outcomes of the cases studied throughout the NEM's evolution between 2024 to 2034. As can be seen, instabilities appear most strongly in later years with the retirement of some key synchronous generation and the increase of IBR that does not have GFM capability.

There is a notable breakpoint of ~30% GFM IBR penetration in an entirely IBR system (i.e. Milestone 3 work) that allows transient stability to be maintained. Note that this breakpoint was found by increasing the proportion of GFM BESS in the case in approximately 5% steps (as a fraction of GFM for the total IBR nameplate rating in the case) as evenly as possible throughout all the regions of the case.

Table 14 Summary and timeline of case results

Year	Demand (GW)	Synchronous (%)	IBR (%)	GFM IBR (%)	Stable?	Islanded Stable?	Notes
2024	8	84	16	34	Yes	Yes	-
2024	8	84	16	0	Yes	Yes	-
2024	32	46	54	35	Yes	Yes	-
2024	32	46	54	0	Yes	Yes	-

Year	Demand (GW)	Synchronous (%)	IBR (%)	GFM IBR (%)	Stable?	Islanded Stable?	Notes
2027	8	52	48	34	Yes	Yes	-
2027	8	52	48	0	Yes	Yes	-
2027	32	35	65	32	Yes	Yes	Some control system setup challenges.
2027	32	35	65	0	Yes	Yes	Only just.
2030	8	44	56	35	Yes	Yes	-
2030	8	44	56	0	Yes	Yes	-
2030	32	20	80	35	Yes	Yes	Challenges with resonances.
2030	32	20	80	8	Yes	Yes	Only just. Copperstring needs to be in GFM to prevent instability.
2034	8	39	61	35	Yes	Yes	-
2034	8	39	61	0	Yes	Yes	Only just.
2034	36	16	84	35	Yes	Yes	Challenges with resonances during islanding.
2034	36	16	84	0	No	No	Strong control system instability.
2034	36	16	84	20	Yes	Yes	-
2034	36	0	100	35	Partial	Partial	Transiently stable, but insufficient voltage support in one area– Partial status not due to insufficient system strength.
2034	36	0	100	0	No	No	Couldn't get past initialisation.
2034	36	0	100	20	No	Partial	Loss of stability upon final fault.
2034	8	0	100	35	Yes	Yes	-
2034	8	0	100	20	No	No	Control system instability.
2034	8	0	100	25	Yes	No	Islanding fails, in-tact OK
2034	8	0	100	29	Yes	Yes	-

Services and GFM IBR deployment timeline

It is as yet unclear whether a GFM IBR device alone will be truly sufficient to supply all the characteristics a wide-area power system requires to remain stable under most conceivable conditions. In particular, further analysis and understanding of phenomena identified in this research stage is required (e.g., phase-angle shifts and remote overvoltages). However, leveraging the fact that a 100% IBR system was found to be operable and stable with the GFM IBR devices and proportions used in this research, a broad initial assumption can be used that it is possible that GFM IBR will deliver the required services to remain at least fundamentally stable. Hence, using this assumption, it can be gauged approximately how quickly system service provision needs to change, and the rate at which GFM IBR technology should be rolled out with the necessary capabilities to maintain system integrity (as will be described in following sections).

Figure 12 and Figure 13 are a combination of the AEMO ISP forecast [39] of the level of generation required to maintain maximum demand supply until 2050, and the identified need to ensure at least 30% of the IBR fleet has grid strengthening capability with the properties described in this report's analysis[10].

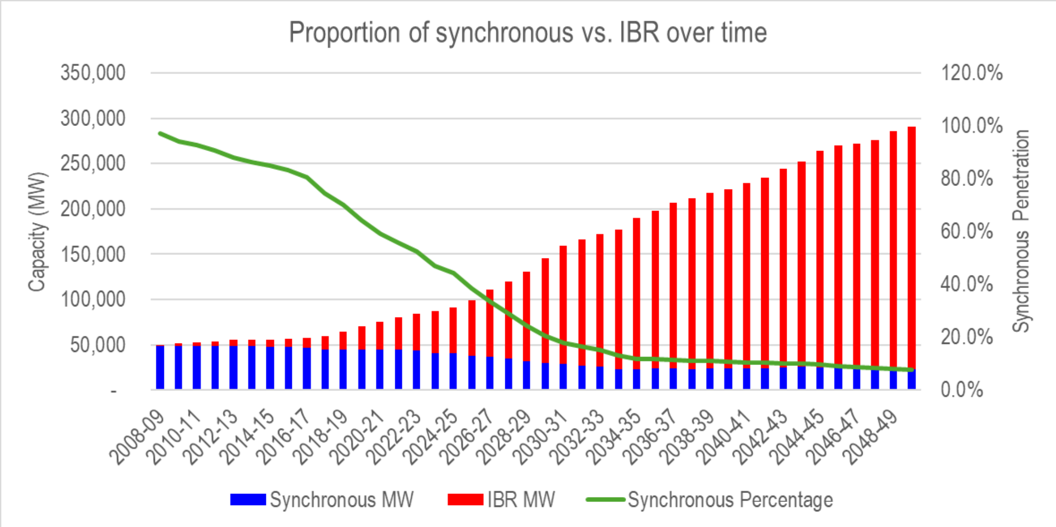


Figure 12 Synchronous penetration over time

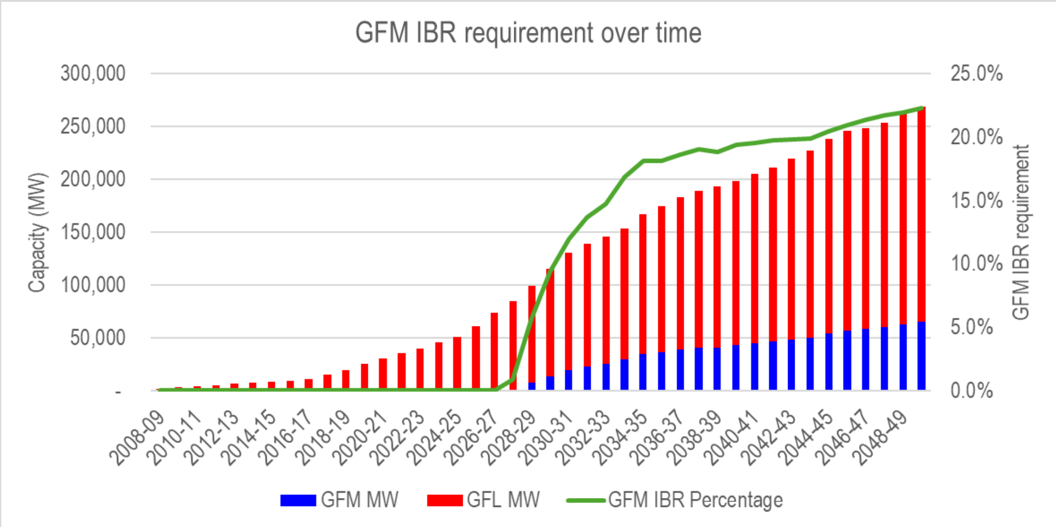


Figure 13 Required GFM IBR penetration over time

It is important to note that these GFM capacity values in these figures are likely to be as optimistically low as the situation could ever be, requiring:

- 100% of remaining synchronous machines being available and online, and in a position to provide material system strength to the remainder of the system.

[10] Note that given uncertainties around many projects, it was assumed that the bulk of the hydroelectric fleet would remain as a true synchronous source (as opposed to IBR-interfaced for some pumped hydro installations).

- The 30% figure for minimum grid strengthening services penetration (from both synchronous and IBR sources) being adequate for all regions and circumstances that may eventuate in operating the NEM.
- All GFM devices being capable of delivering every service needed to maintain grid stability, despite any financial impost this may have on their viability.

However, even with modest assumptions regarding the practical operation of a power system, the requirements for GFM IBR capacity increase as shown in Figure 14 below.

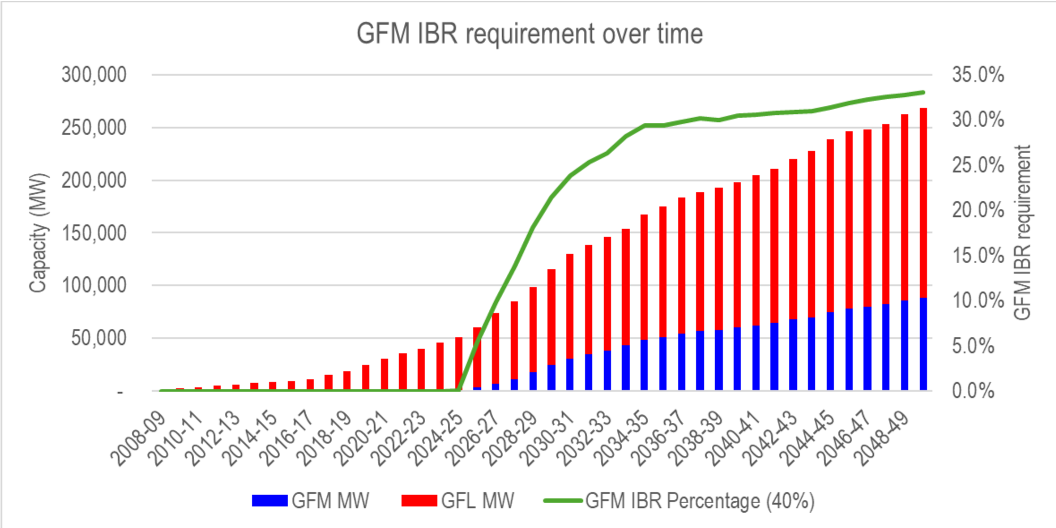


Figure 14 Required GFM IBR penetration over time with modest assumptions

In this scenario, the assumptions have been modified as such:

- Of the available synchronous fleet, only 90% are available at any one time.
- A more conservative figure of 40% grid strengthening services is required to maintain stability of the IBR-dominant system.
- All GFM devices still deliver all the services required to maintain grid stability (same as previous).

Where this leaves the NEM is a likely near-immediate need to deploy devices such as GFM IBR with characteristics that can maintain grid stability in an IBR-dominant system, and notably, if all GFM devices are sufficiently capable, nearly 1.5 times more GFM IBR technology deployment required by 2034 (compared to the more optimistic assumption scenario described above).

Negative sequence current changes

It was hypothesised that high proportions of GFL devices may have a negative effect on the ability of the power system to produce negative sequence current during faults, which is used by some protection relays to aid in discriminating whether the fault lies within their zone of operation or not. As such, settled negative sequence to positive sequence ratio was monitored for all the cases studied. The definition of a “settled” current reading is shown in a red oval Figure 15 below, whereby it refers to a moment in time during the fault (often right before the near end of the faulted line is cleared) where the positive and negative sequence measurements have reached a near-steady state.

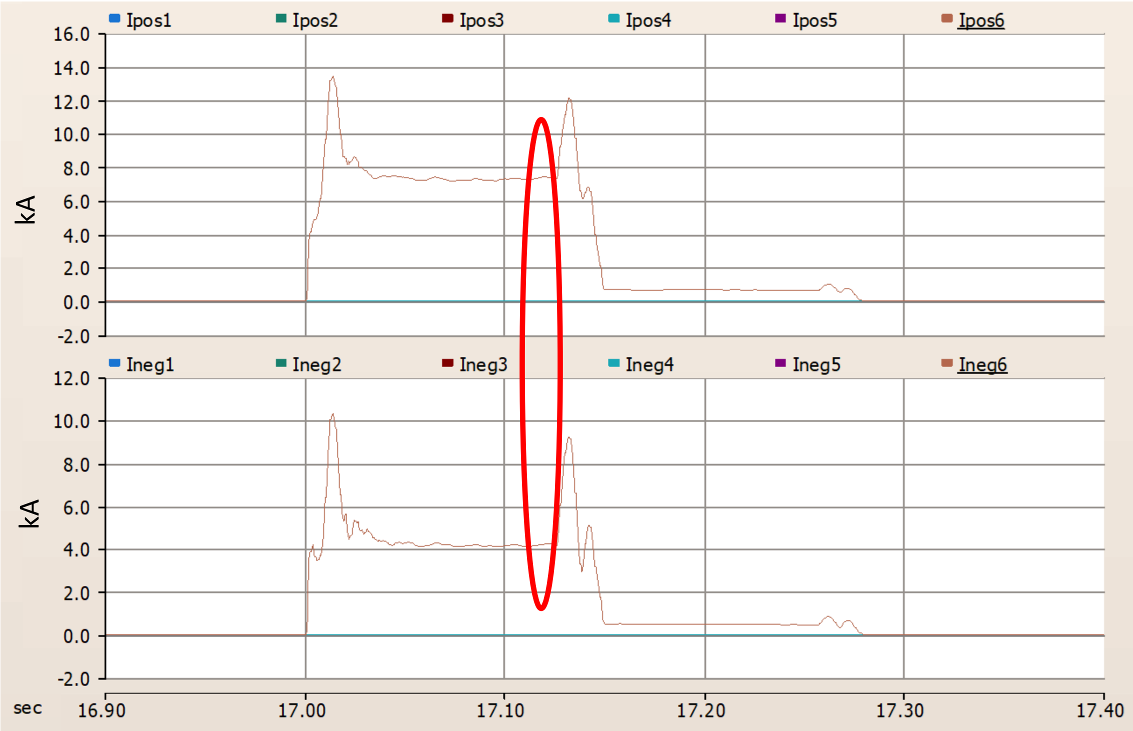


Figure 15 Defining how a settled measurement was determined

The results indicated that, at least for the GFL and GFM generator models used in these studies, there was only a material change to these ratios when a theoretical 100% IBR system was used. It was observed that topology changes between 2024 to 2034, and ratios of GFM to GFL devices online made little difference.

The parameter with the greatest impact on these ratios was the overall MVA of devices dispatched, with higher levels of generator dispatch during periods of higher demand leading to greater negative to positive sequence fault current ratios. This is shown in Figure 16 below, where the minimum, maximum and average values as the topology and generator dispatch mix had little impact on these ratios.

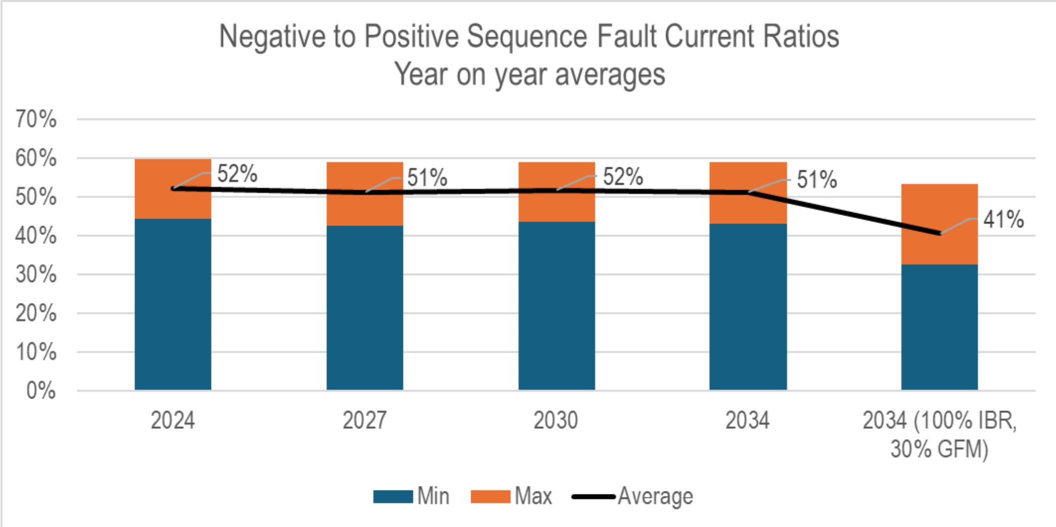


Figure 16 Negative to positive sequence fault current ratios over time

Figure 17 shows a breakdown by common dispatch types across years, which highlight that the GFM/GFL mix does not lead to a major change between cases, however the total demand and hence MVA of online devices has a far larger bearing on the matter.

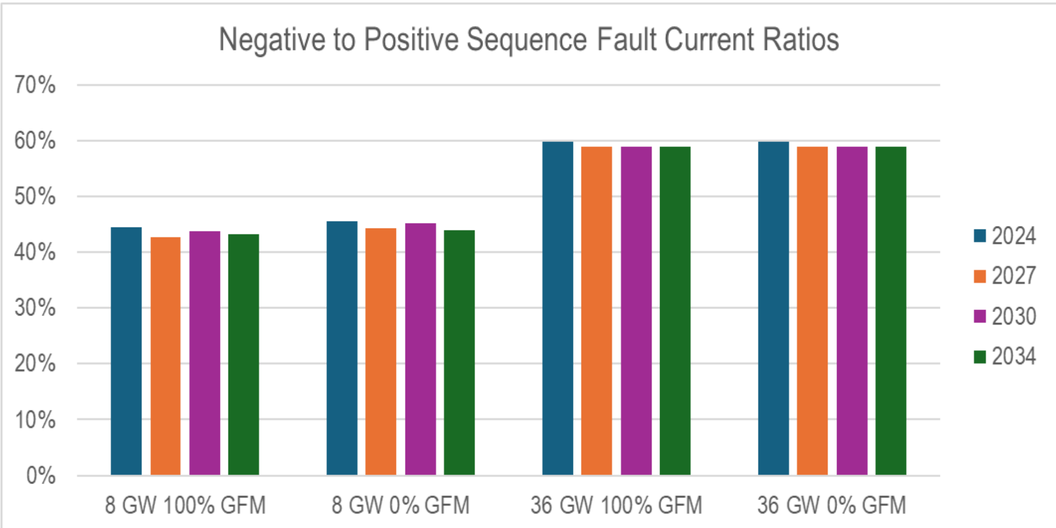


Figure 17 Breakdown of negative to positive fault current ratios by year and GFM/GFL mix

There is a notable change in the <u>quality</u> of the fault current components as the generation mix changes over time. Consider the images show in Figure 18. These are fault current component measurements for the same scenario and same fault across What can be seen is a general change in profile of the sequence components as the system evolves to be more reliant on IBR technology. Distinct peaks at fault inception, near-end clearance are reduced over time, and a settled state is less clearly identified.

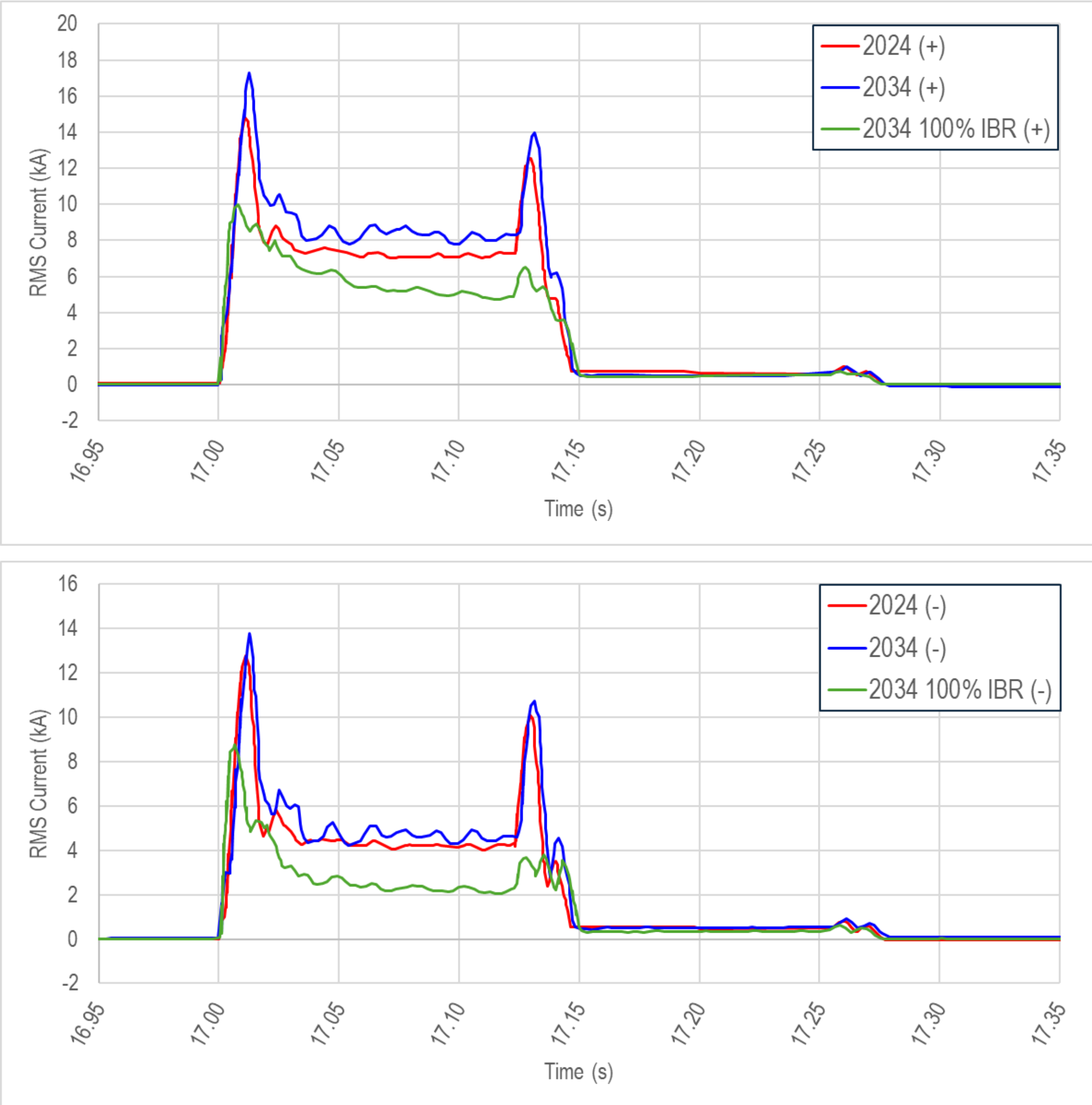


Figure 18 Positive (top) and negative (bottom) sequence measurements, from 2024, 2034, and 2034 with 100% IBR

Whether such changes in fault current sequence profiles are of a concern for the operation of network protection relays is something that must be further studied, with the inclusion of appropriate network protection relays in the case and an evaluation of any performance degradation.

Comparison with OEM GFM BESS models

It was noted that the minimal reduction in negative phase sequence current contribution during faults was not consistent with similar research in the area [40], and it was postulated that the EPRI GFM BESS model may have advanced capability in NPS current delivery that is not supported by other models that other researchers may be using. To test this, a sensitivity study was completed whereby all the GFM BESS were replaced with an OEM's GFM BESS offering.

As can be seen in Table 15, for the option evaluated there is a slight reduction in the proportion of negative phase sequence current delivered, but not significantly (<5%). Checks were also made to confirm whether the operating point of the BESS makes a difference to the provision of fault current magnitudes and components, or whether the existence of the GFL PV plant in each REZ model may be contributing to negative phase sequence current provision. Differences were found but again were not material enough to explain the deviation from other researcher's findings.

Table 15 2034 OD8 case with OEM GFM BESS (all BESS are GFM).

Component	EPRI GFM BESS (C30)	OEM GFM BESS (C42)	OEM GFM BESS (C42a)	OEM GFM BESS (C42b)
BESS target MW	0	0	High export	High export
Generic PV plant	In-Service	In-Service	In-Service	Out of Service
Disturbance 1 – South Morang VIC				
Waveform peak	22.3 kA	26.4 kA ↑	26.6 kA ↑	25.6 kA ↑
RMS peak	8.8 kA	9.0 kA ↑	8.4 kA ↓	8.2 kA ↓
Positive Sequence (settled)	6.3 kA	6.3 kA	6.2 kA ↓	5.8 kA ↓
Negative Sequence (settled)	2.4 kA	2.2 kA ↓	2.2 kA ↓	2.1 kA ↓
Negative to Positive ratio (approx.)	38%	35% ↓	35% ↓	36% ↓
Negative to Total ratio (approx.)	27%	24% ↓	26% ↓	26% ↓
Disturbance 2 – Wollar NSW				
Waveform peak	19.8 kA	21.3 kA ↑	20.4 kA ↑	19.3 kA ↓
RMS peak	6.8 kA	7.1 kA ↑	6.8 kA	6.6 kA ↓
Positive Sequence (settled)	4.9 kA	5.1 kA ↑	5.0 kA ↑	5.0 kA ↑
Negative Sequence (settled)	2.1 kA	2.1 kA	2.1 kA	2.1 kA
Negative to Positive ratio (approx.)	43%	41% ↓	42% ↓	42% ↓
Negative to Total ratio (approx.)	31%	30% ↓	31%	32% ↑
Disturbance 3 – Tarong QLD				
Waveform peak	28.0 kA	33.4 kA ↑	32.0 kA ↑	33.9 kA ↑
RMS peak	11.1 kA	11.7 kA ↑	11.4 kA ↑	11.9 kA ↑
Positive Sequence (settled)	8.7 kA	8.8 kA ↑	8.7 kA	8.5 kA ↓
Negative Sequence (settled)	4.7 kA	4.7 kA	4.6 kA ↓	4.5 kA ↓
Negative to Positive ratio (approx.)	54%	53% ↓	53% ↓	53% ↓
Negative to Total ratio (approx.)	42%	40% ↓	40% ↓	38% ↓
Disturbance 4 – Robertstown SA				
Waveform peak	22.3 kA	26.7 kA ↑	25.3 kA ↑	22.8 kA ↑
RMS peak	8.2 kA	8.5 kA ↑	8.8 kA ↑	8.2 kA
Positive Sequence (settled)	6.3 kA	6.3 kA	6.4 kA ↑	6.1 kA ↓
Negative Sequence (settled)	2.4 kA	2.1 kA ↓	2.2 kA ↓	2.1 kA ↓
Negative to Positive ratio (approx.)	38%	33% ↓	34% ↓	34% ↓
Negative to Total ratio (approx.)	29%	25% ↓	25% ↓	26% ↓

Comparison of different negative sequence measurement methodologies

To continue to determine the source of any potential errors, a comparison was done in FFT-based negative phase sequence measurement methods.

In this work, an FFT module was used to analyse the components of the fault current and determine magnitudes of positive and negative current contributions. To do so, the FFT block was placed in sequence calculation mode, and all harmonics up to the 15th were summated in both the positive and negative sequence channels. However, it is noted that it is also common practice to simply observe the fundamental component from the positive and negative channels of the FFT output. The difference in approaches is shown in Figure 19.

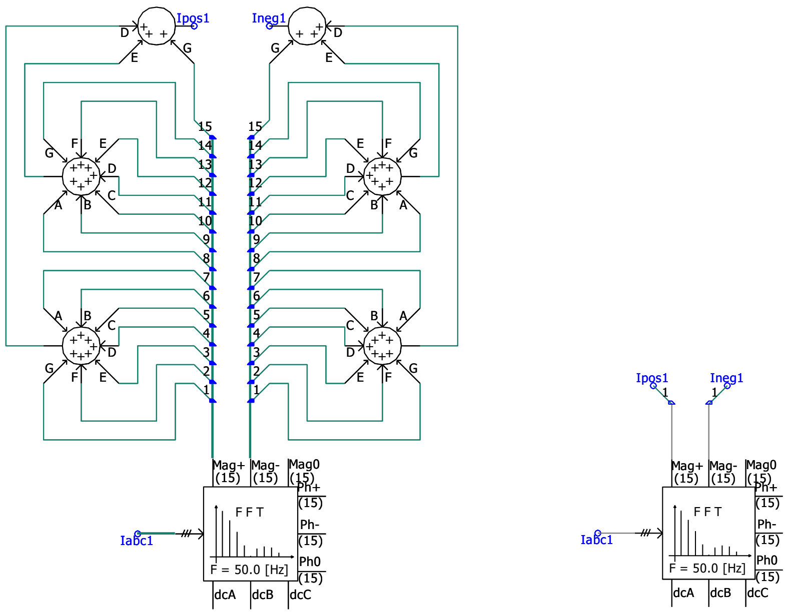


Figure 19 Differences in phase sequence component extraction

Checks were made to see if the difference in approaches could lead to materially different results for the metrics collected regarding negative phase sequence. Examples are shown in Figure 20 and Figure 21. While there are considerable differences for fault inception and clearance between the two methods, as described previously measurements were taken once the response had settled, immediately prior to the near breaker opening. At this point, the differences between the measurement approaches had reduced to approximately 10% for short faults and 6% for longer faults.

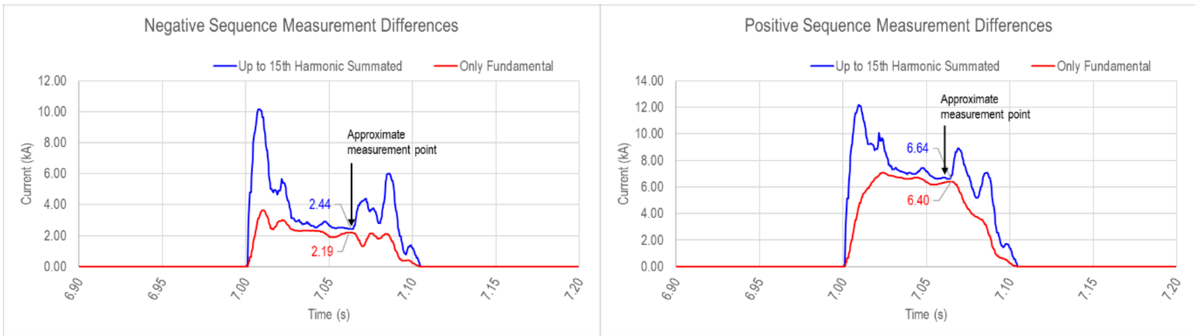


Figure 20 Differences in results for a short fault

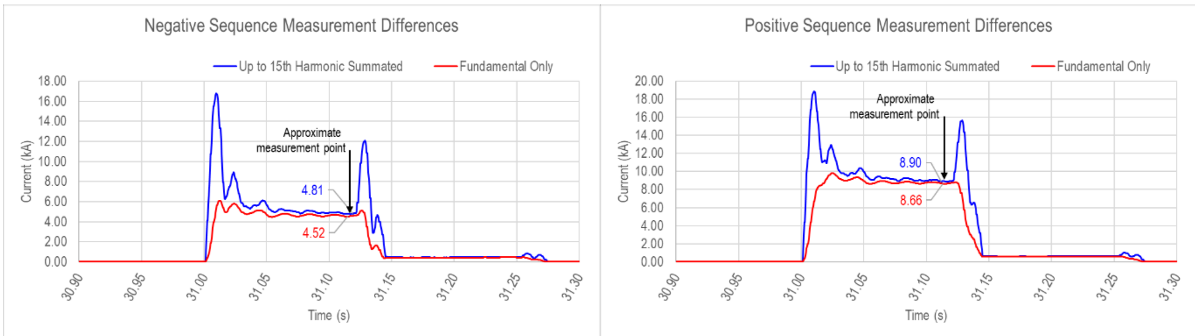


Figure 21 Differences in results for a longer fault

Additionally, because a key metric being calculated is both the *difference* between cases, and the *ratio* between positive and negative phase sequence currents, so long as a consistent method is used, there should be no inaccuracies in using either method. It was therefore concluded that the measurement method was unlikely to have introduced material errors into the measurement of negative phase sequence fault current values, and hence the above analysis stands.

The researchers continue the assumption that both the EPRI GFM BESS model and the OEM GFM BESS model may have had additional negative phase sequence injection capability compared to the models which the other researchers in this area appear to be using. Future work should seek to integrate a variety of OEM models and generic models with varying capabilities beyond what the authors of this report currently have access to, to explore this area further.

Peak fault current changes

The waveform peak of fault currents did not show a large variance throughout the years studied. In the later years, the increased interconnection of the network (and hence reduced network impedance) saw an increase in the peak magnitudes observed, particularly following the inclusion of the QNI connect, Queensland Supergrid South, New England REZ network upgrade, and the SA Mid-north upgrades.

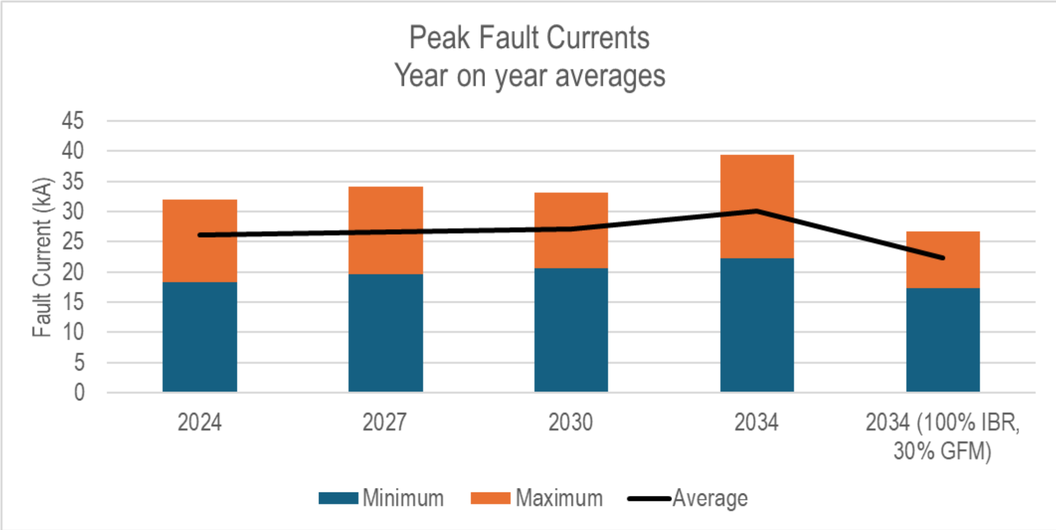


Figure 22 Peak fault current changes

Again a reduction with a 100% IBR NEM, but it is noteworthy that the minimum is only slightly less than the 2024 case.

When this is broken down into dispatch scenarios across the years, we see a similar trend in that year on year there are approximate increases in minimum and maximum fault currents, with the same trend showing that increases associated with maximum demand (hence maximum machines online) lead to the highest values of peak fault currents.

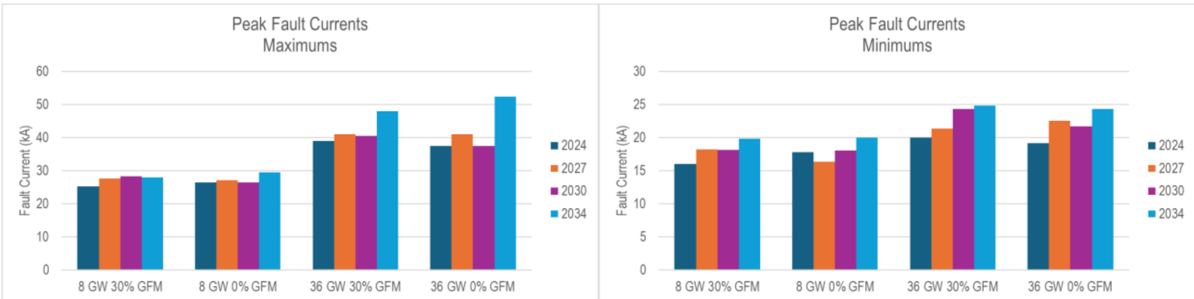


Figure 23 Peak fault current minimums and maximums

This outcome was determined to be a result of the following. Although an IBR device has a reduced fault current provision (1.2 to 2.0 pu maximum) compared to a synchronous machine (2.0 to 3.0 pu), due to their intermittent energy source it was assumed that more IBR devices needed to be online but operating at a lower MW output (e.g. between 30 to 70% depending on the scenario), while synchronous generators could be fewer in number connected but operated at a far higher MW export levels (e.g., between 50 to 100% depending on the scenario). This is consistent with the AEMO ISP view on the dramatically increased amount of variable generation required to meet what is a modest growth in underlying demand, as shown in the capacity diagram of the 2024 ISP and reproduced in Figure 24 for convenience. As can be seen, the <u>ratio</u> of generation to load required increases dramatically over the upcoming years to account for energy source variability.

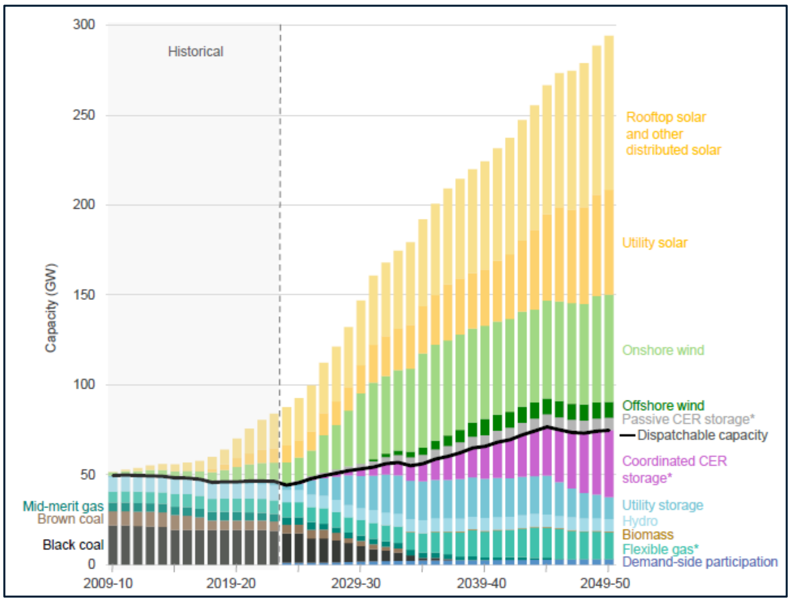


Figure 24 NEM Capacity requirements as described by the 2024 AEMO Integrated System Plan (Figure 2 therein)

Hence, it is arguably not surprising that fault current magnitudes may not dramatically change as, illustrated by this simple example:

- Synchronous machine:
  - Unit size = 100 MVA
  - Unit output = 90 MW (90% utilisation – constant energy source)
  - Fault current provision = 3.0 pu
  - Total fault current amount = 100 x 3.0 = **300 MVA**
- Inverter Based Resource:
  - Unit size = 250 MVA
  - Unit output = 90 MW (36% utilisation – variable energy source)
  - Fault current provision = 1.2 pu
  - Total fault current amount = 250 x 1.2 = **300 MVA**

Phase angle shifts

Analysis was performed on the case to determine how phase angle changes were affected by the topology changes and proportions of synchronous, GFL IBR and GFM IBR dispatched in a case.

The measurement of a phase angle shift can be performed in several ways, however, to be able to focus on the synchronising ability of the power system (as opposed to post-fault swings and synchronous machine behaviour) it was decided to sample each generator's phase angle immediately prior to a fault and 50ms into the fault. This is shown in Figure 25, where the phase angle at each generator point of connection is represented by a differently coloured line. The difference in values between these two temporal points was then calculated as the phase angle shift amount. This may not represent the absolute maximum phase angle shift seen in a given disturbance, however so long as the measurement sample points are consistent for all disturbances in all cases, it will provide a common comparison about changes in the system behaviour.

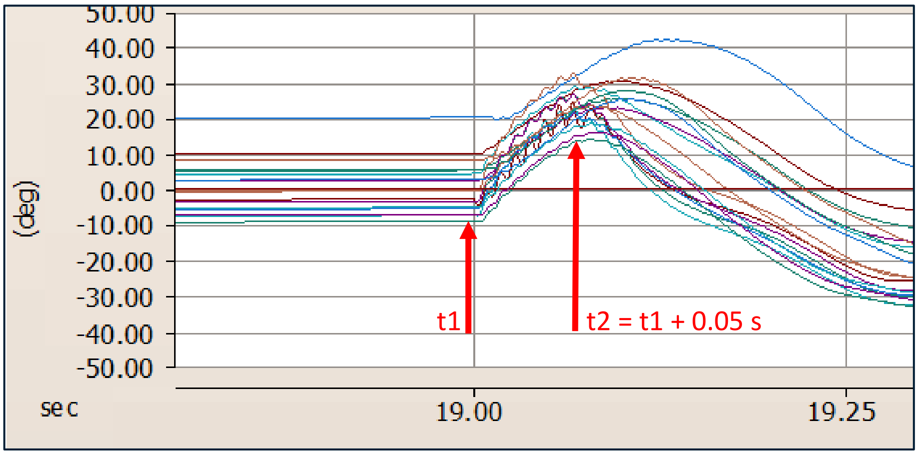


Figure 25 Temporal sampling of generator phase angle changes for fault applied at t = 19.0 s

The change for the in-fault phase angle is calculated simply by ($Phase_{t2}$ - $Phase_{t1}$). Such sampling allowed insight into how the power system "moves" as the topology and generator composition evolves.

It was quickly noted that there were clear differences in phase angle shift amounts between systems with high and low levels of synchronous machines online, and systems with differing levels of interconnections. For example, scenarios in 2024 that included many synchronous machines online saw phase angles shift during the fault only for those generators within the faulted region, indicating a strong decoupling of the system regions and a general insensitivity to remote disturbances. In Figure 26, note that many of the phase angles for the fault application period remain flat.

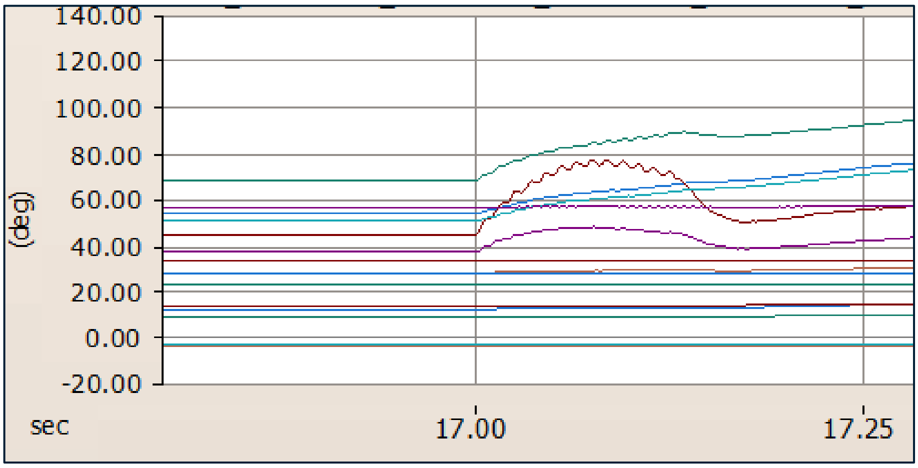


Figure 26 Phase angles of a 2024 high-demand case with many synchronous machines online

In contrast, for the 2034 version of the same demand scenario and fault, there is an increase in the number of generator phase angles (represented by different coloured lines) which are affected by the fault across the NEM. In this case, while synchronous machines were still present, there had been several retirements of machines in the interim.

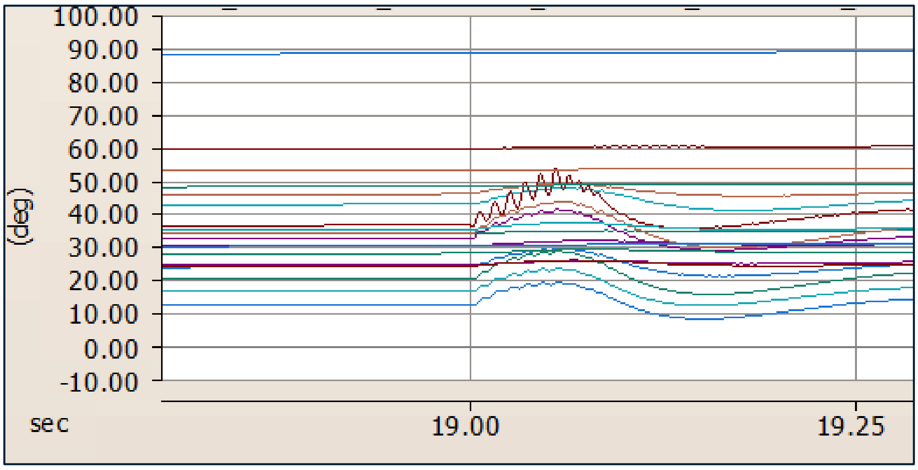


Figure 27 Phase angles of a 2034 high-demand case with reduced synchronous machines online

Such phase angle differences are even more noticeable when a lighter, low-demand scenario is evaluated. Note the difference in phase angle changes between the 2024 case and the 2034 case. The fault causes a shift in angles across the entire system in 2034 (i.e., all the coloured lines shifted in response to a fault), where it was previously contained to only the nearby generators in 2024 (i.e., many of the coloured lines remained steady).

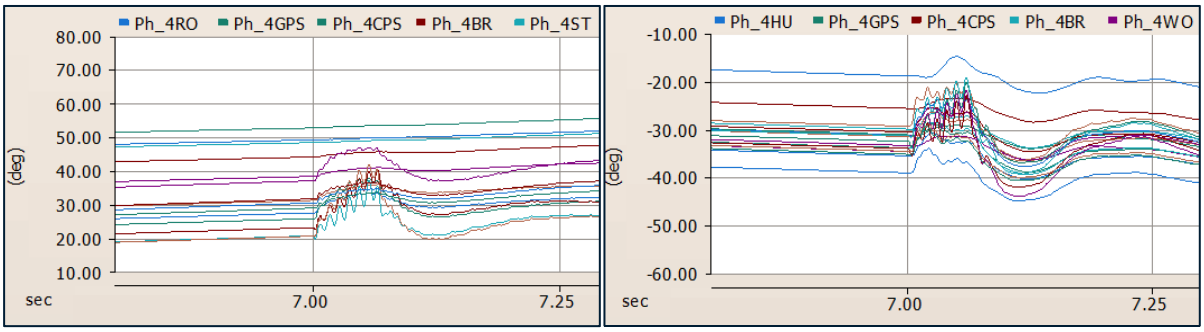


Figure 28 System phase angle shift differences between 2024 (left) and 2034 (right) for a low-demand scenario[11]

Taking this even further, scenarios that had no synchronous machines online whatsoever and were entirely reliant on GFM IBR to provide system strength saw even greater phase angle shifts, as shown in Figure 29. These scenarios were entirely stable, however given that IBR controllers may be susceptible to instability for large phase-angle jumps, such behaviour of an IBR-dominated system is noteworthy, especially given that extremely remote plant may react to disturbances.

[11] Please note that the absolute angle value is not of importance; it is the difference/delta between the pre-disturbance value and the peak disturbance value (or even whether an angle remains unchanged) that provides insight into how the system has shifted.

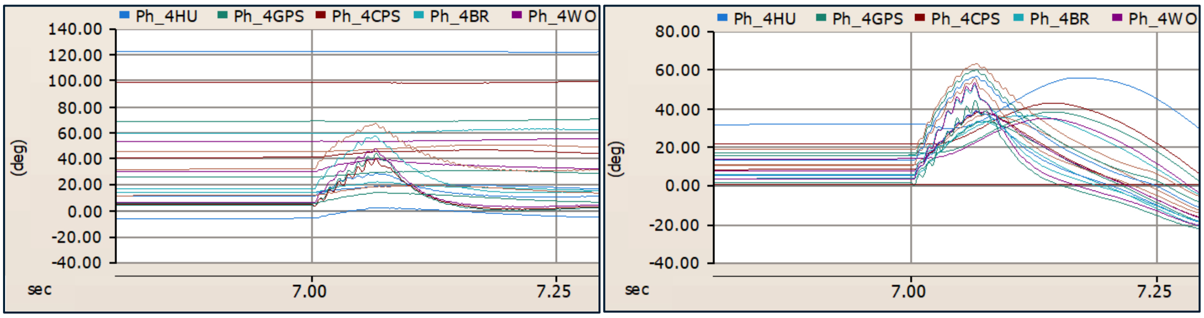


Figure 29 System in-fault phase angle differences for a 100% IBR high demand (left) and low demand (right) scenario

To summarise, what is demonstrated by the above Figure 25 to Figure 29 images is that there is a relationship between the proportion of IBR generation online and both the amount and geographical distribution of phase angles that shift in the system due to a fault. That is, the more synchronous machines that remained in the system, the more contained the phase angle shift, and the higher the proportion of IBR, the wider the phase angle shift. This, however, did not necessarily mean that wider phase angle shifts resulted in an unstable system; Moreso that all NEM phase angles are more likely to shift for a disturbance.

The above examples can also be explored quantitatively. The following graphs indicate both the minimum and maximum phase angle shifts seen by a given system. Note that:

- Systems that have a minimum phase angle shift of **zero** indicate a system that is either has high insensitivity to disturbances (strongly compensates / maintains status quo for any remote disturbances in the system) or has low coupling between regions. Conversely, the greater the magnitude of the minimum phase angle shift, the more sensitive the entire system is to the disturbance and the less the online generators can compensate.
- Systems that have a large maximum phase angle shift may be because either:
  - The system is heavily loaded, and the disturbance caused a key circuit connecting generation to load to be removed, or;
  - The devices present in the system are unable to effectively compensate for the given disturbance.

  It is therefore less clear whether maximum phase angle changes are indicative of a weak system or simply a system where disturbances have the potential to make a larger impact overall.

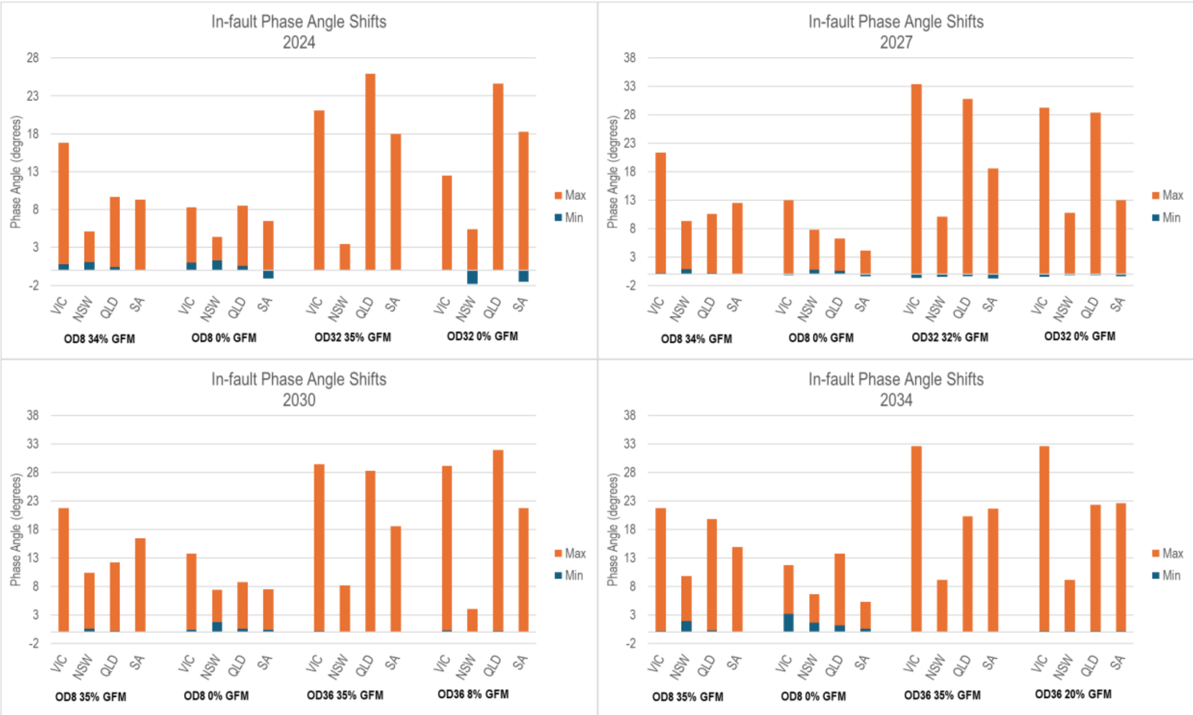


Figure 30 Phase angle shifts versus scenarios, years and disturbances

The above quantitative analysis suggests that:

- Scenarios that do not contain GFM devices will generally see larger minimum phase angle shifts across the system, however systems with GFM devices may still be subject to large maximum shifts depending on the disturbance applied.
- Higher demand scenarios may see larger phase angle shifts due to greater levels of energy flows interrupted, however they may also see a greater containment of phase angle shifts to a localised region by virtue of more plant being online and able to compensate.
- For later-year low demand scenarios, the greater interconnection between regions and reduced synchronous machines online will see phase angle shifts across the entire NEM when compared to earlier year scenarios.

A final metric of interest in evaluating phase angle shifts was the grouping present in phase angle shifts across the system, whereby scenarios that contained many grid-strengthening devices saw “bands” of phase angle shifts on a regional basis, while weak systems with minimal grid-strengthening devices saw phase angle shifts far more spread.

For example, compare the phase angle spreads below in Figure 31 and Figure 32. In the 2024 higher demand case with more synchronous machines online, three distinct bands are seen for:

- Generators in the affected region;
- Generators one region away; and
- Generators 2 regions away.

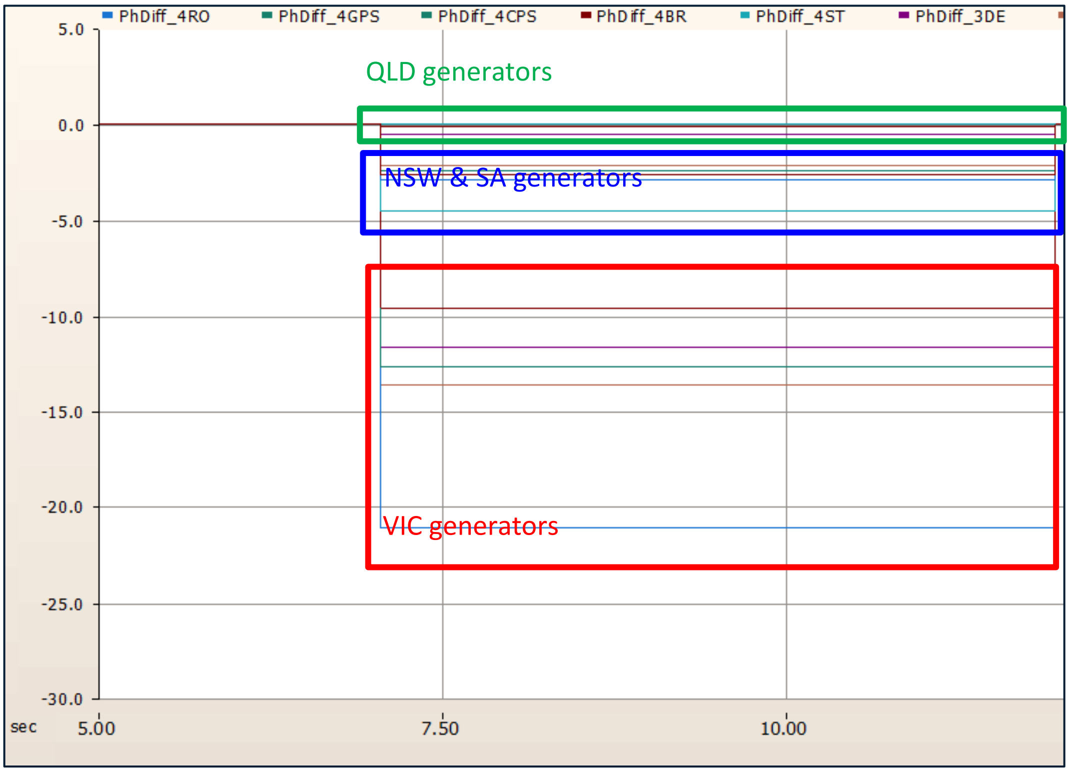


Figure 31 Phase angle shift banding for 2024 high demand case

Such regional grouping was not as distinct in the case with more GFL technology and fewer synchronous machines online, presumably due to reduced interregional resistance and higher GFL IBR penetration leading to greater phase angle swings (despite it being 30% GFM).

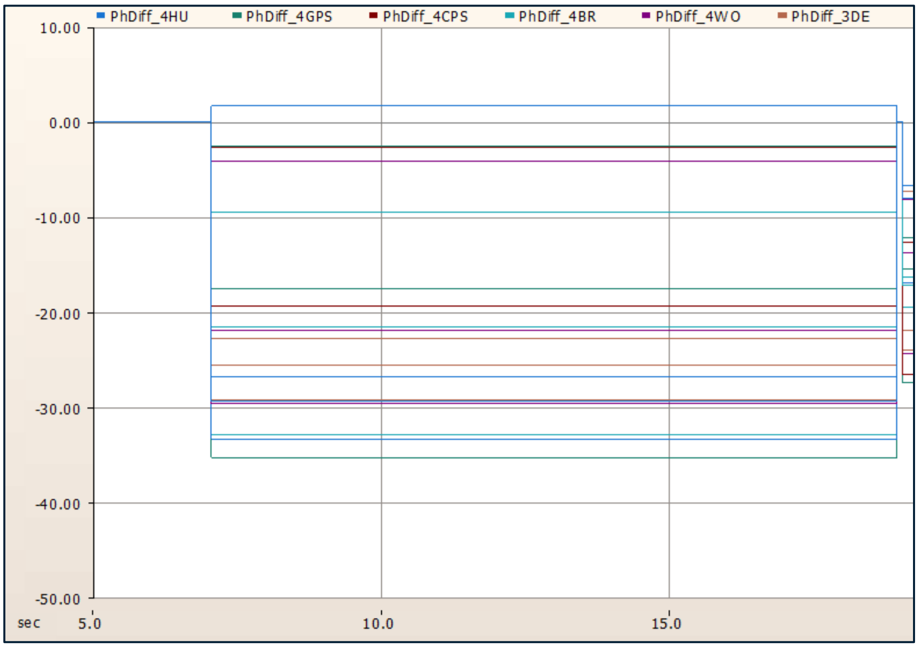


Figure 32 Increased phase angle shift spread for 2034 low demand, high IBR case

It is possible that grouping such as this could be used as a metric for determining the sensitivity and hence strength of a system to disturbances. The increased spread in later cases may also suggest that with the potential for swings to be seen more widely in interconnected systems, there will be a commensurate increased need to study the NEM in a wide-area format, rather than taking regional equivalences at known natural breakpoints (typically interconnectors).

Voltage dips

Another metric of case stability and robustness used was measuring the length of voltage dips seen across the system, as measured at major load centres in each region. A component was developed to automatically measure these threshold crossings, whose structure is shown in Figure 33.

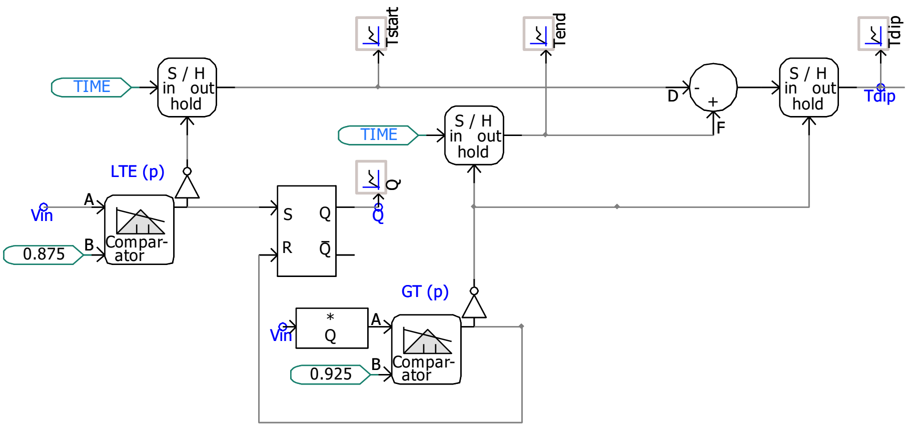


Figure 33 Voltage dip threshold measurement device

The logic works as follows:

- Should the RMS voltage of the chosen node drop below 0.875 pu (evaluated by a less-than-equal pulse comparator):
  - A sample of the simulation time is made and held.
  - An S-R flip-flop is set, allowing the second comparator to measure the voltage.
- Once the voltage exceeds 0.925 pu threshold (evaluated by a greater-than pulse comparator):
  - A second sample of the simulation time is made and held.
  - The S-R slip-flop is reset (allowing future samples to occur)
  - The second sample time is subtracted from the first sample time, and a result calculated.

The voltage threshold values were chosen as they are 2.5% either side of 0.9 pu (the lower nominal voltage bound) which provides 5% hysteresis to prevent oscillatory triggering. An example of these thresholds as they apply to a measured RMS voltage is shown in Figure 34.

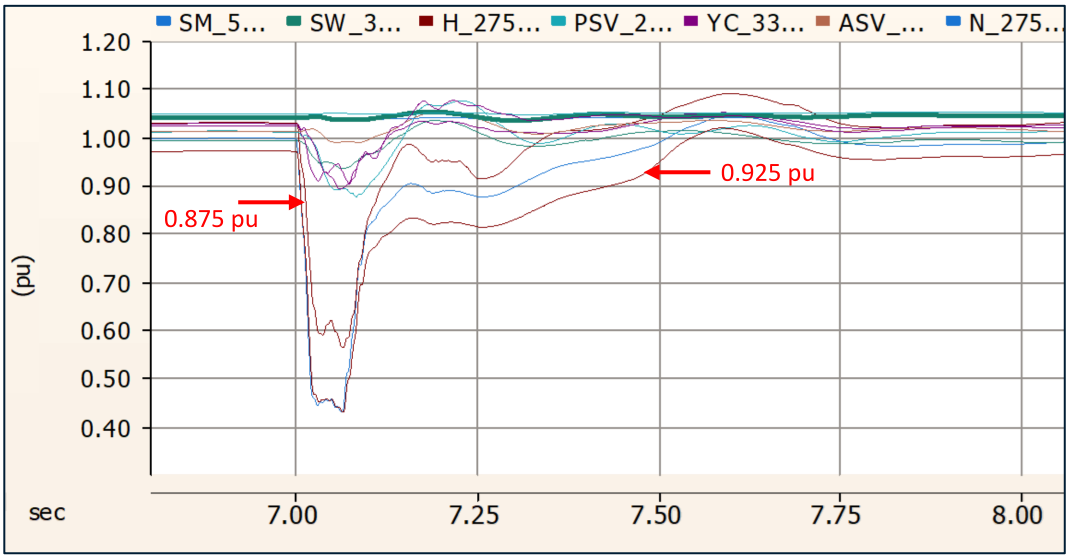


Figure 34 Example of voltage dip triggering thresholds

When comparing the maximum voltage dip times across the evolution of the NEM cases in Figure 35, there are several takeaways from the data:

- High-demand cases will have longer voltage recovery times due to the increased load on the system and hence operation closer to the nose of the P-Q curve.
- Cases which have both no grid forming IBR devices and higher system demand saw longer voltage recovery times than high demand cases with grid forming capability.
- The difference in voltage recovery times between systems with and without GFM IBR devices is less pronounced at lower loading levels.

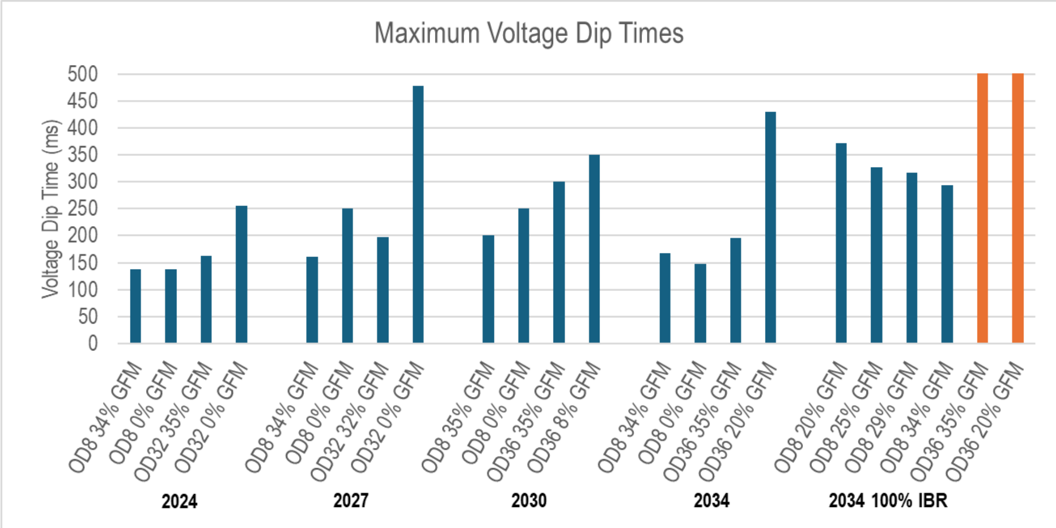


Figure 35 Maximum voltage dip times across cases (orange are indefinite)

It therefore appears that including modest amounts of grid forming IBR throughout the system is an important feature to reduce voltage recovery times during heavily loaded periods.

Notably the 2034 100% IBR NEM case has some of the worst performance overall for voltage dip recovery times, with the two high-demand cases having a node voltage fail to recover following a disturbance. This was investigated and determined to be a result of insufficient general reactive support margins in the region following the removal of synchronous machines, and not a dynamic IBR controller stability problem. An example is shown in Figure 36. It is dynamically stable and well damped, but there is insufficient localised generation to aid in voltage recovery to the 0.925 timer reset point.

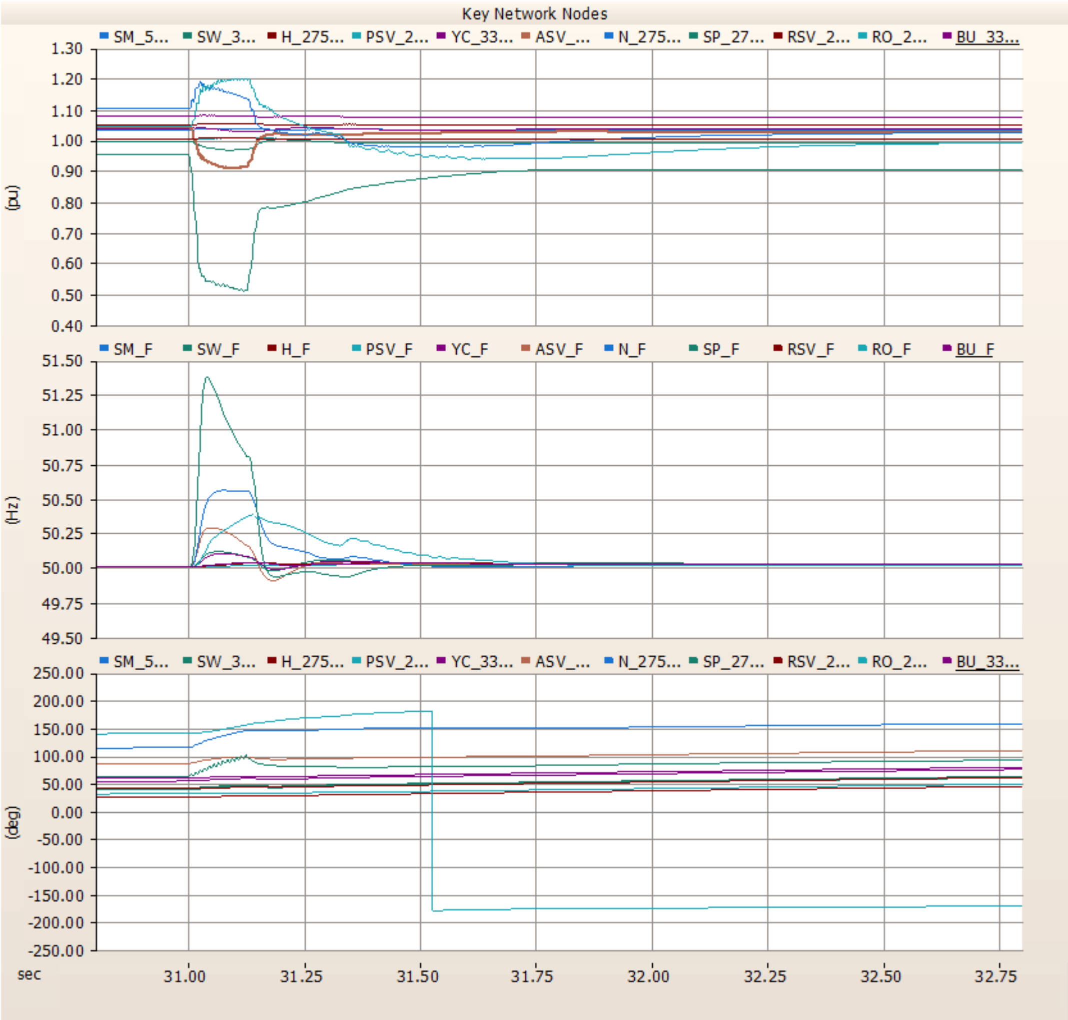


Figure 36 Failure for voltage to recover (South Pine QLD, green trace)

Otherwise, the trend shown for 2034 100% IBR in Figure 35 shows that for light loading cases, improvement in voltage recovery can be made by increasing the proportion of GFM IBR devices online.

Damping

Damping performance was evaluated in a qualitative manner, looking at the level, duration and frequency of oscillations post fault clearance across network voltage, unit output, and interconnector flows. These were then ranked between 0 (growing instability) and 5 (almost no swing at all) for each major case evaluated. The results are shown in Figure 37.

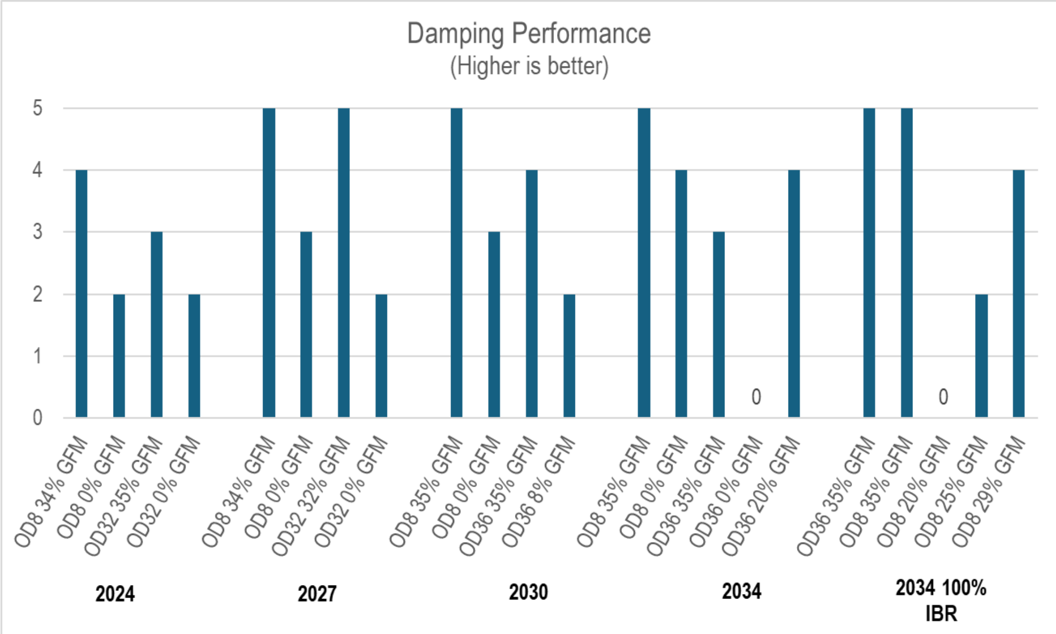


Figure 37 Damping performance

Some general trends that were seen include:

- Greater levels of GFM IBR resulted in stronger damping performance. N.B. these GFM devices were in Droop mode (as opposed to VSM mode or virtual oscillator).
- Reduced levels of synchronous machines online generally resulted in reduced large, slow oscillations post fault clearance (with the given IBR control algorithms chosen for this work, most notably being frequency droop GFM).
- Lower operational demand coupled with higher proportions of GFM devices consistently had the best damping performance for all the cases evaluated.

It is worth noting that 100% IBR only cases can still exhibit post-fault recovery low-frequency swings with less-sinusoidal characteristics compared to cases containing synchronous machines. This occurs even without any GFM devices in virtual synchronous machine mode (i.e., all GFM devices in Droop mode) and is a natural result of the power flow swings across a distributed network with complex impedances. An example of such is presented in Figure 38.

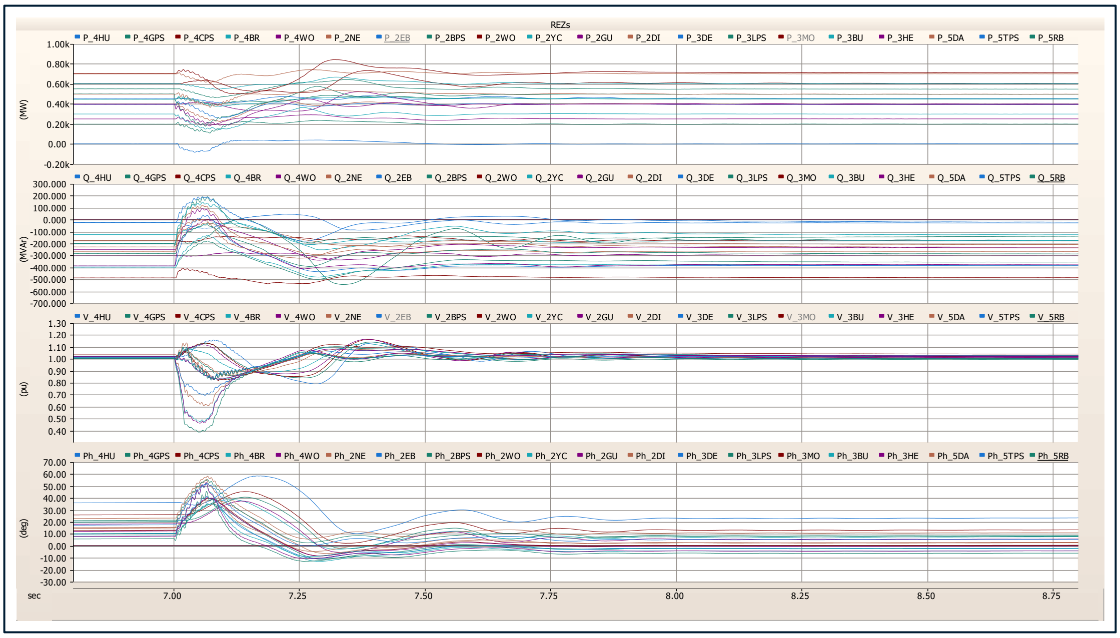


Figure 38 Post fault recovery swings in a 100% IBR system (30% GFM, droop mode)

Hence, post-fault damping is a quality that remains relevant to monitor and retain even in high penetrations of IBR systems without the traditional rotor angle stability problem from synchronous machines.

General voltage support

It was observed within some cases that the retirements of certain synchronous generators resulted in:

- Excessive line charging from lightly loaded 500 kV lines, resulting in a need to remove them from service to maintain voltages within 1.1 pu for low load scenarios; and
- Occasions where an inability to recover to nominal voltages occurred in high-demand load centres following a fault (tending towards voltage collapse). An example is shown in Figure 39.

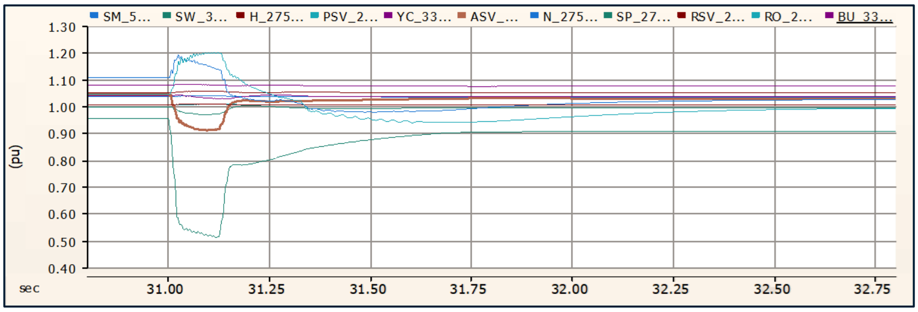


Figure 39 Inability to recover voltage in Queensland South Pine area

Such issues are not in the realm of “synchronous versus IBR plant superiority”, but more related to a shift in the physical location of major generation centres to areas of the network with a higher impedance to major load centres. It is a reactive power margin planning matter more-so than a stability matter, but it is worth highlighting here.

For excessive 500 kV line charging, given the increasing extremes of variability of NEM loading, it is a recommendation from this work that new 500 kV lines being built across the next 10 years are shunt-compensated, but that those shunts are switchable. In this way, during light load conditions the shunts can be in service alleviating the capacitive effect, while under high demand conditions they can switched out to utilise the additional capacitance to aid with bolstering voltage.

With regard to inability to recover voltages to nominal bounds and voltage collapse problems, there are two aspects to recommend:

- Deployment of new SVC-based dynamic reactive support options should be a last resort. With the potential for far more variability in the system both dynamically during disturbances and statically due to demand, SVCs which tend to block capacitive injection once voltages drop below ~0.8 pu may exacerbate voltage collapses. Instead, it is recommended that as such devices are due for replacement, STATCOMs (potentially even grid-forming variants) are instead installed to give the system better dynamic support for all eventualities, as these devices are capable of reactive support across a wider voltage range and with variable aggressiveness of injection as the situation warrants.
- The key voltage support nodes of each region may shift or require further support as the NEM topology evolves, and additional reactive support devices may need to be installed at nodes where previously there was none. <u>Noting the limitations and narrow applicability using this very simplified NEM topology</u>, it was seen that the following nodes would greatly benefit from additional reactive support as topologies change and generators retire:
  - Newcastle region in New South Wales
    - The closure of several key plants in the region (Vales Point and Eraring) while continued high demand persists make supporting voltage during high demand particularly challenging. The Waratah Super BESS goes some way to assist, but it alone appears to be insufficient to maintain healthy voltage for all scenarios.
  - Throughout Copperstring in far-north Queensland
    - From the scenarios conducted, the sheer size of the Copperstring REZ means that evacuating energy from the REZ to the southern load centres needs substantial voltage support along the pathway. Additionally, the extensive 500 kV network also poses an overvoltage challenge when lightly loaded. Therefore, there is a need for a flexible voltage support solution to maintain the far-north Queensland region and the Copperstring REZ both within acceptable voltage limits and to prevent voltage collapse under high transfer.
  - The Adelaide metropolitan area.
    - The closure of almost all large synchronous generation in the Adelaide metro region will pose a challenge for the maintenance of voltage during high

demand scenarios. The existing SVCs in the region may no longer be sufficient, and augmentation will be required to assist in preventing voltage collapse in this uniquely metro-concentrated topology.

4.3 100% IBR NEM scenario (Milestone 3)

The work within Milestone 3 aimed to look at what changed in both NEM performance and metrics when the NEM no longer had any synchronous machines online at all – generator or synchronous condenser. While the setup and several performance differences from these scenarios have already been discussed in Section 4.2, this section dives into more detail about some 100% IBR-only results found through the studies.

4.3.1 Milestone 3 Objectives

A key area of investigation was to understand how a 2034 NEM that contains no rotating machines may perform, and what technical properties need to be provided by generation sources to be able to maintain a robust and stable system.

Such a system contains no electromagnetically coupled devices, meaning aside from the physical properties of the inverter componentry, the inherent beneficial uncontrolled responses from generators occurring at short timeframes are not present, and the system is dependent on fast controller action to maintain stability and coherence.

This work sought to identify any needs of the system that are different from the previous scenarios studies in which rotating machines were available and determine the performance difference between systems with and without rotating machines. It is built upon the work and cases completed in Milestone 2 and effectively is a special case for the 2034 mainland NEM scenarios.

4.3.2 Case setup

The 100% IBR case was set up in the same way as the previous NEM evolution cases, only with all synchronous machines taken offline and energy generation shifted to the IBR devices in service. As a starting point, all BESS devices in the model set to grid-forming mode for both low demand (8 GW) and high demand (36 GW) scenarios.

A load-flow was solved and the results imported into PSCAD for initialisation.

4.3.3 Results

Please note that the results for Milestone 3 simulations are also presented in the Milestone 2 section, as it was a logical extension of the work conducted as part of Milestone 2. The following results are therefore items unique to the Milestone 3 work of a 100% IBR NEM evaluation.

Frequency

This scenario allowed the exploration of the notion of continued applicability of wide-area system frequency; in an entirely asynchronous system with no rotational mass to slow down, does frequency have the same meaning and function? Would an energy imbalance instead manifest as a localised voltage depression? Or is the emulation of frequency shifts to respond to a mismatch in system active power balance within inverter controllers equivalent to that of a system with a link to rotational masses?

The studies completed as part of the 100% IBR NEM scenarios seemed to suggest that this line of enquiry is of little value, and that frequency retains its function as a metric of system active power balance, both with and without frequency sensitivity of load enabled (i.e., a load relief of 0.5% or 0%) and irrespective of the operational mode of the GFM source.

Overvoltages and phase angle shifts

In running the cases, the following was observed that during faults in the low demand case, extremely remote generators responded relatively strongly to disturbances thousands of kilometres away, resulting in mild overvoltage conditions in these remote regions. An example is shown in Figure 40 below of a two-phase-to-ground fault applied on a 500 kV line between Loy Yang and South Morang (as described in Table 7), which had a resultant in-fault overvoltage at the Copperstring connection point some 2500+ km away.

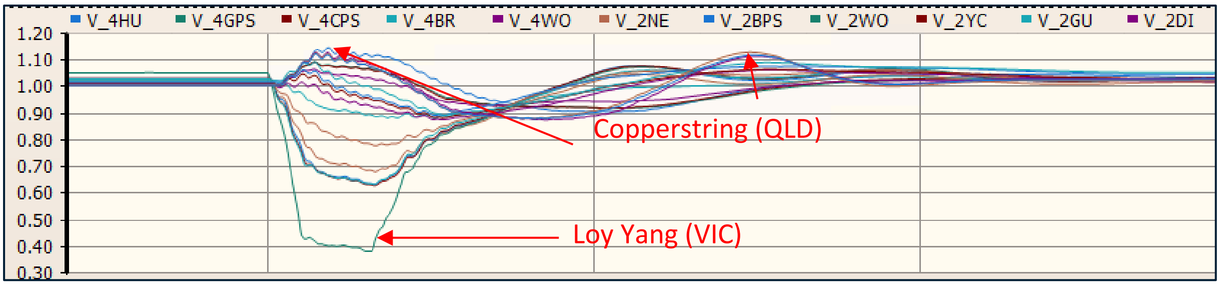


Figure 40 Remote overvoltages in response to remote faults

It is important to note that such an overvoltage cannot be a function of simple reactive power exchange, which is a local phenomenon. Instead, this outcome may be indicative of:

- Related to the global phase-angle change that occurs in a rotating machine-free system.
- A strong coupling across the system which was not as prevalent in the cases that contained even small amounts of synchronous machines, and/or
- An as-yet to be understood reaction of IBR controllers to fast phase-angle jumps in the absence of any rotating machines.

When this is considered in the context of the minimum phase angle shifts being values other than zero for many of the 8 GW demand cases studied, it suggests that the entire NEM may be moving in response to a credible fault no matter where it occurs within the system. Figure 41 shows this by virtue of there being increased magnitudes in minimum phase angle shifts for the lower demand cases with lower amounts of GFM IBR, and reduced angles in minimum phase angle shifts for cases with higher demand cases with higher amounts of GFM IBR.

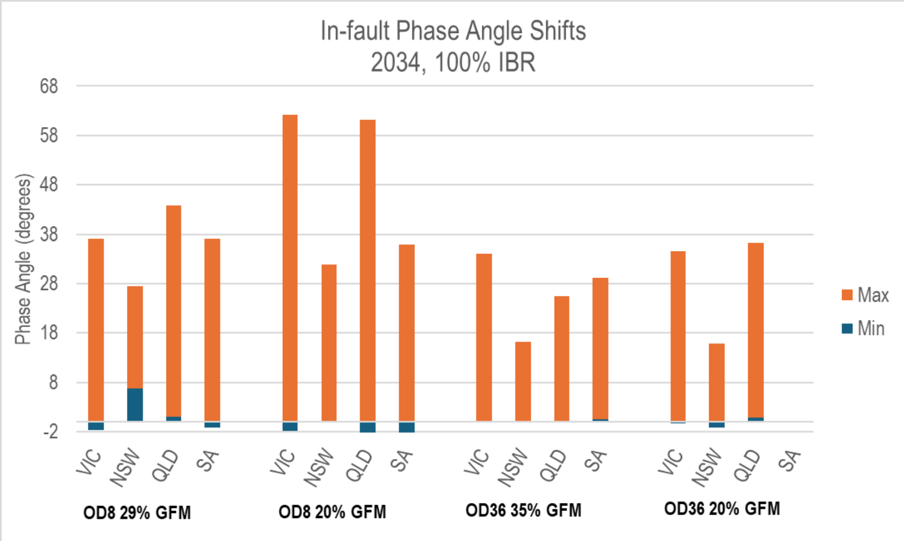


Figure 41 2034 100% IBR Phase Angle Shifts

The implications of this are not yet clear. Certainly, there has been a propensity for extremely remote overvoltages to occur during the fault as shown previously, but whether this is indicative of a system that is marginally stable or otherwise 'unhealthy' is unknown. It must considered that the likelihood of the NEM operating without any synchronous machines is almost zero, however should such phenomena be witnessed in a NEM with very high IBR penetration, it can at least be noted that it has been observed in 100% IBR scenarios and is not a completely unexpected behaviour.

A note on the use of equivalent network models

It may be inferred that in a system without synchronous machines, disturbances will be experienced by a broader geographical range of equipment present in the network, if not all of them. This may undermine the concept of using equivalent networks in the NEM, whereby it is considered that if a plant is electrically remote it is unlikely to participate in any disturbance response for the plant under study. If this is true, this could have a strong negative effect on the ability to process new generator connections quickly, as to understand the impact of a new generator connection on the system, the whole NEM in full detail may need to be used for every simulation run. This would dramatically increase both the computational resources required and the run-time to complete the studies. However, as the phenomena has only been seen in 100% IBR systems to date, it remains as a cautionary note to keep in mind in high-IBR systems, rather than a recommendation that requires a change to processes.

Fault current

Perhaps unsurprisingly, there is a substantial reduction in the amount over fault current available for a 100% IBR NEM compared to a scenario that has a minimal amount of synchronous machines online. A typical trend for the measured points is shown in Figure 42. Although the reduction varies by geographical location and network interconnectivity, the general trend is a reduction across all scenarios and locations studied.

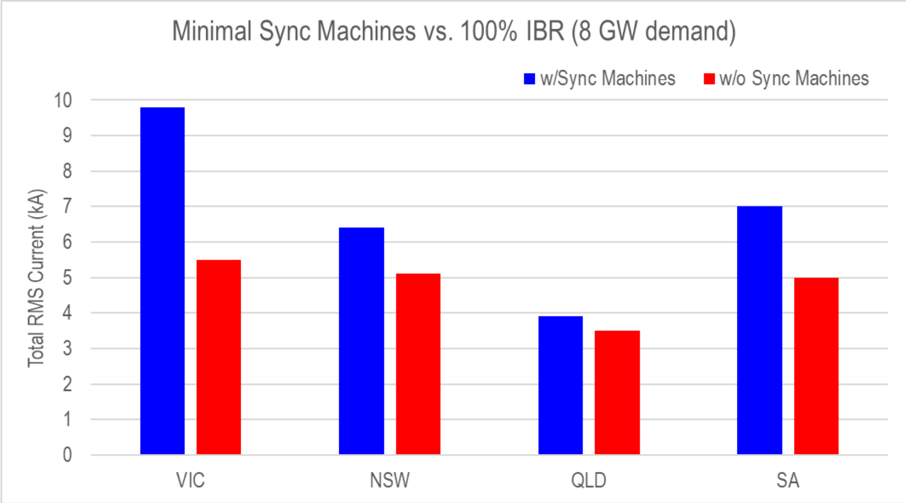


Figure 42 RMS fault current versus generator type dispatched

However, when looking at the quality of the fault current components, a more nuanced picture emerges.

Negative phase sequence component

The results indicate that there is also a reduction in the amount of negative phase sequence fault current injection when the NEM is operating without synchronous machines. The level of variance depends strongly on the location of the fault and the nearby connectivity of the network, however a general reducing trend is seen across all nodes studied for the 100% IBR case.

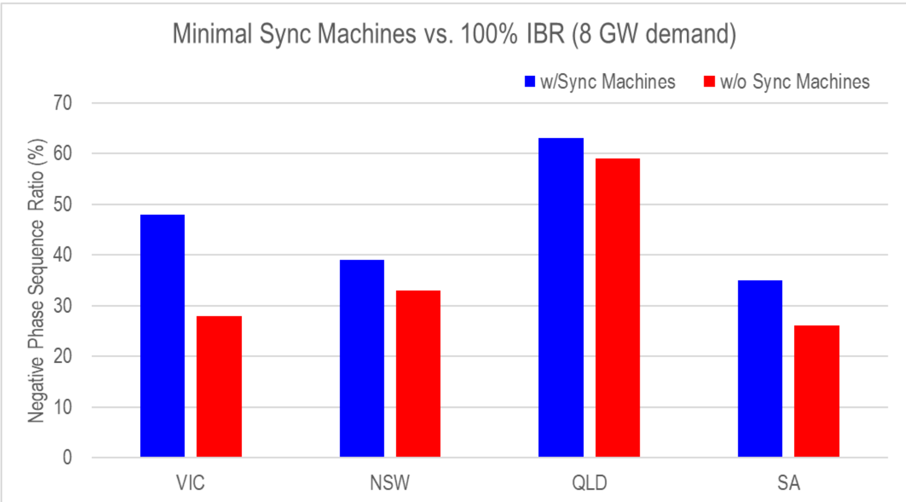


Figure 43 Negative phase sequence fault current reductions with 100% IBR

As the generation amount dispatched is increased, a corresponding increase in negative phase sequence ratios occurs, indicating provision is related to the overall MVA of generation online within the case, however it not necessarily proportional.

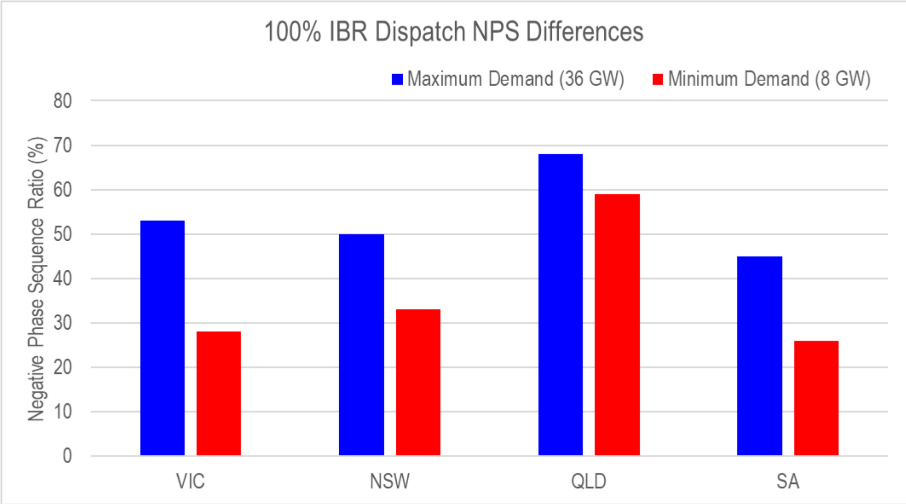


Figure 44 Negative phase sequence ratio changes with generation dispatched

In general, the reduction and general variability in negative phase sequence component of fault current may be problematic for network protection relays and should be an area of further research in future stages.

Fault current waveshape

Note the differences in the current waveshapes in Figure 45. The figure on the left is for a 100% IBR NEM scenario, while the figure on the right has some synchronous condensers retained online. The waveshape of fault current in the 100% IBR NEM scenario has far higher non-sinusoidal and notched components present on the first swing. Additionally, the synchronous machine scenario allows for a much higher DC component to be present in the fault current compared to the 100% IBR scenario, which may be useful for fault current discrimination.

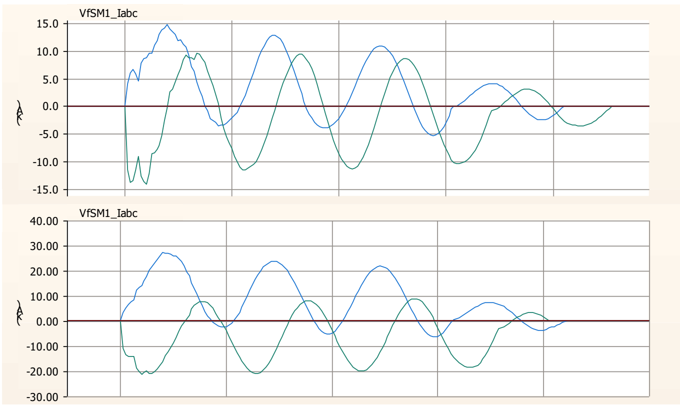


Figure 45 Comparison of fault current waveforms. 100% IBR (left), minimal synchronous (right). 20ms/div.

Depending on the algorithms used in fault detection relays, this may result in mismeasurement and unintended operation of the protection relay operating on the current.

Resilience to critical faults

Given the substantial redistribution of generation sources across a 2034 NEM, a new fault condition was found in the Queensland region for the maximum demand case that had the potential for higher impact than the standard fault which had been applied across previous cases. This fault, on the 275 kV circuit between Gladstone and Callide, had the potential to disrupt over 1 GW of energy flow.

A comparative study was conducted between a 100% IBR NEM case and a case with minimal synchronous machines online. The resultant response between cases was dramatically different, as shown in Figure 46 and Figure 47.

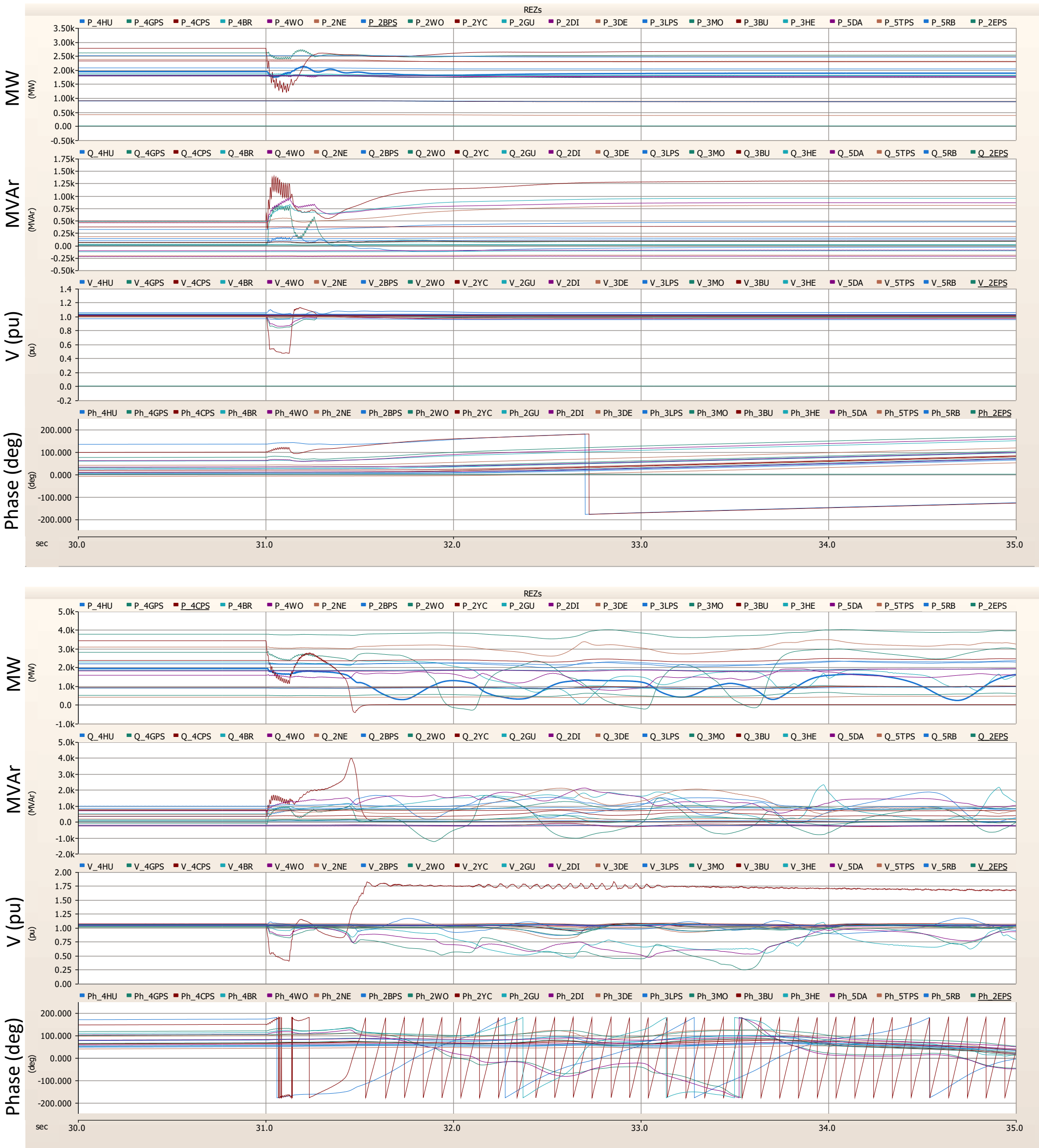


Figure 46 Generator response 2034 case with minimal synchronous machines (top) and 100% IBR (bottom)

The crucial differentiator between these cases appears to be insufficient reactive current injection and control in the region both during and following the fault in the 100% IBR scenario, precipitating a system voltage collapse. The nearby REZ (Callide) attempted to inject very large amounts of reactive power following fault clearance to counteract the collapse, however this ultimately caused a local overvoltage event at its point of connection, causing a tripping of the REZ (Figure 48), further exacerbating the lack of reactive current injection.

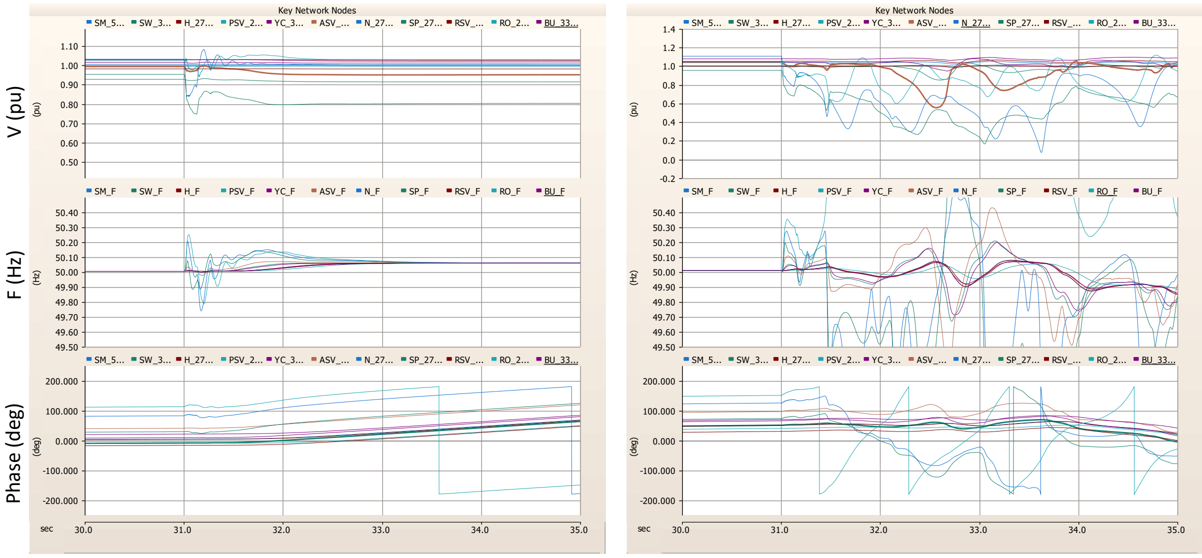


Figure 47 Network key nodes response 2034 case with minimal synchronous machines (left) and 100% IBR (right)

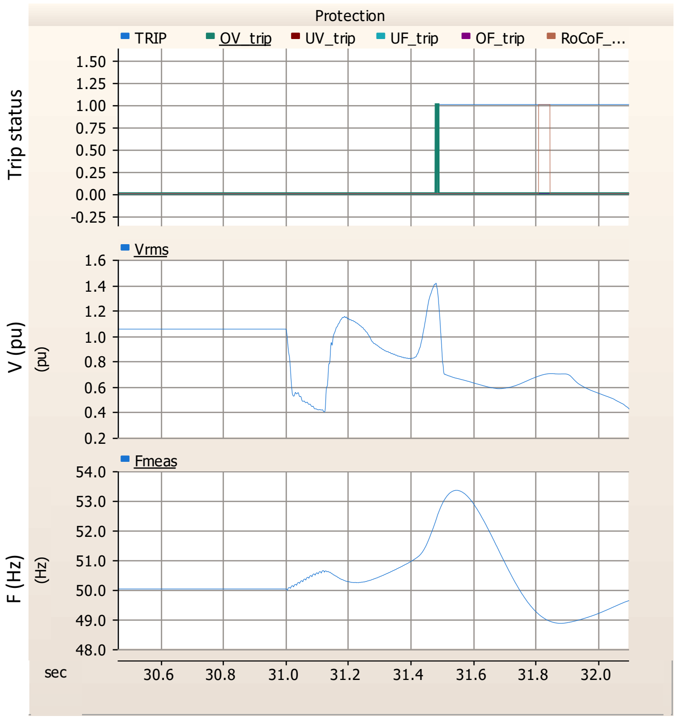


Figure 48 Overvoltage event of the Callide REZ

It is worth pointing out that the case with minimal synchronous machines online also tended towards collapse (South Pine voltage settled at 0.8 pu) but evidently did not cross the voltage collapse profile nose and instead settled at precarious value for the remainder of the simulation.

Note that this was not considered to be an IBR fast-controller instability issue, as despite the collapsing system, controller frequency tracking and internal references were still sensible (as they could be) for this operating point. An example of a nearby GFL plant PLL frequency tracking signal is shown in Figure 49, which is a plausible representation of the system's state.

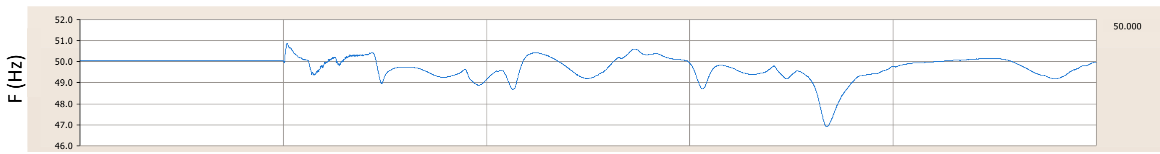


Figure 49 Nearby GFL PLL tracking signal (1s/div)

Given this sequence of events, this means that it is not necessarily an inherent lack of capability of IBR resources leading to a voltage collapse, but rather:

- The specific network reactive support requirements have likely shifted to different geographical locations as major generation centres have shifted.
- Provided that equipment in the field can tolerate it, expanded protection relay settings for REZs in crucial nodes for maintaining system voltage may benefit a system comprising 100% IBR.

GFM Network Resonance Interactions

- Setup of the 8 GW cases found that notional 10% harmonic filter capacitors included at the MV buses of the REZs could not be enabled in some instances. This is because the reduced network load in this low-demand case exposed some natural resonant network points in the sub-200 Hz range, which strongly interacted with the IBR controllers in the REZs. This was not observed in the cases with synchronous machines, indicating that these machines may a harmonic sink for lower orders.

Low demand 2034 cases with GFM tech saw harmonic filters (10% of MVA rating) needing to be disabled to prevent resonances occurring – an area for further investigation. Generators were readily able to offset the reactive power contribution with ample headroom. Not seen in the high demand case, presumably due to significantly higher damping provided by bulk load points.

Inclusion of plant harmonic filters saw a resonant point fall within the primary controller bandwidth – resonances that fell under 200 Hz saw extreme instability from the GFM BESS component. Shifting this resonance to a higher point (above approximately 190 Hz) saw a rapid return to stability for the device.

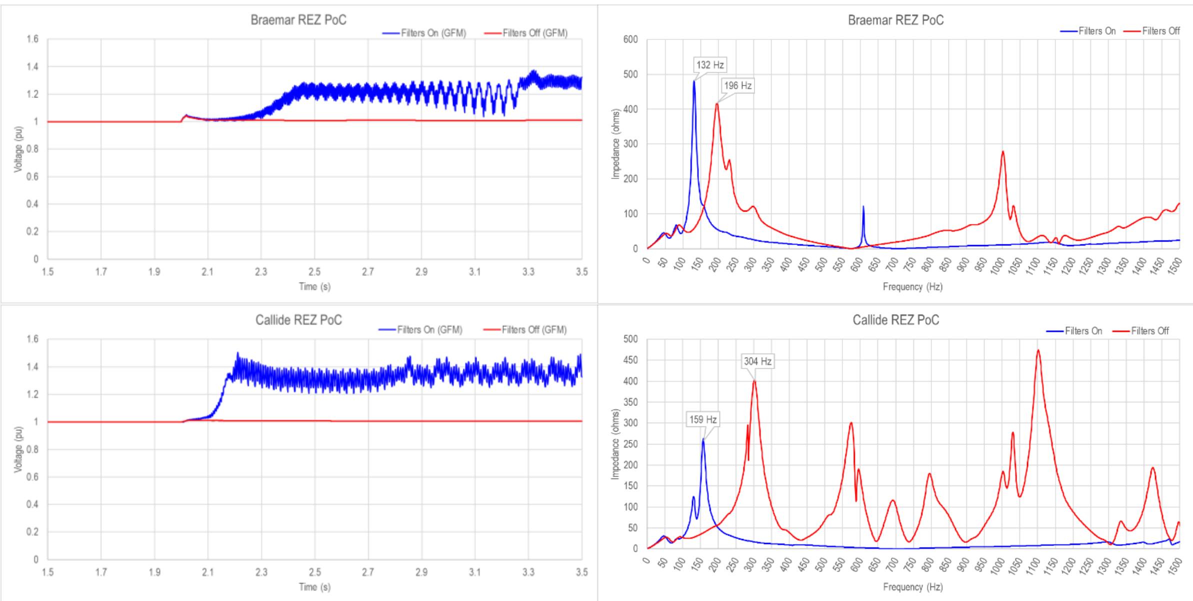


Figure 50 Shifting resonant points

Such behaviour was also seen in high-demand situations where a REZ found itself radial to the remainder of the system, such as the Braemar REZ during an islanding scenario, where it was now located at a stub at the bottom of Queensland, or the New England REZ in the 2030 case where the 500kV network was not yet constructed, leaving the New England REZ as a stub connected to Armidale 330kV.

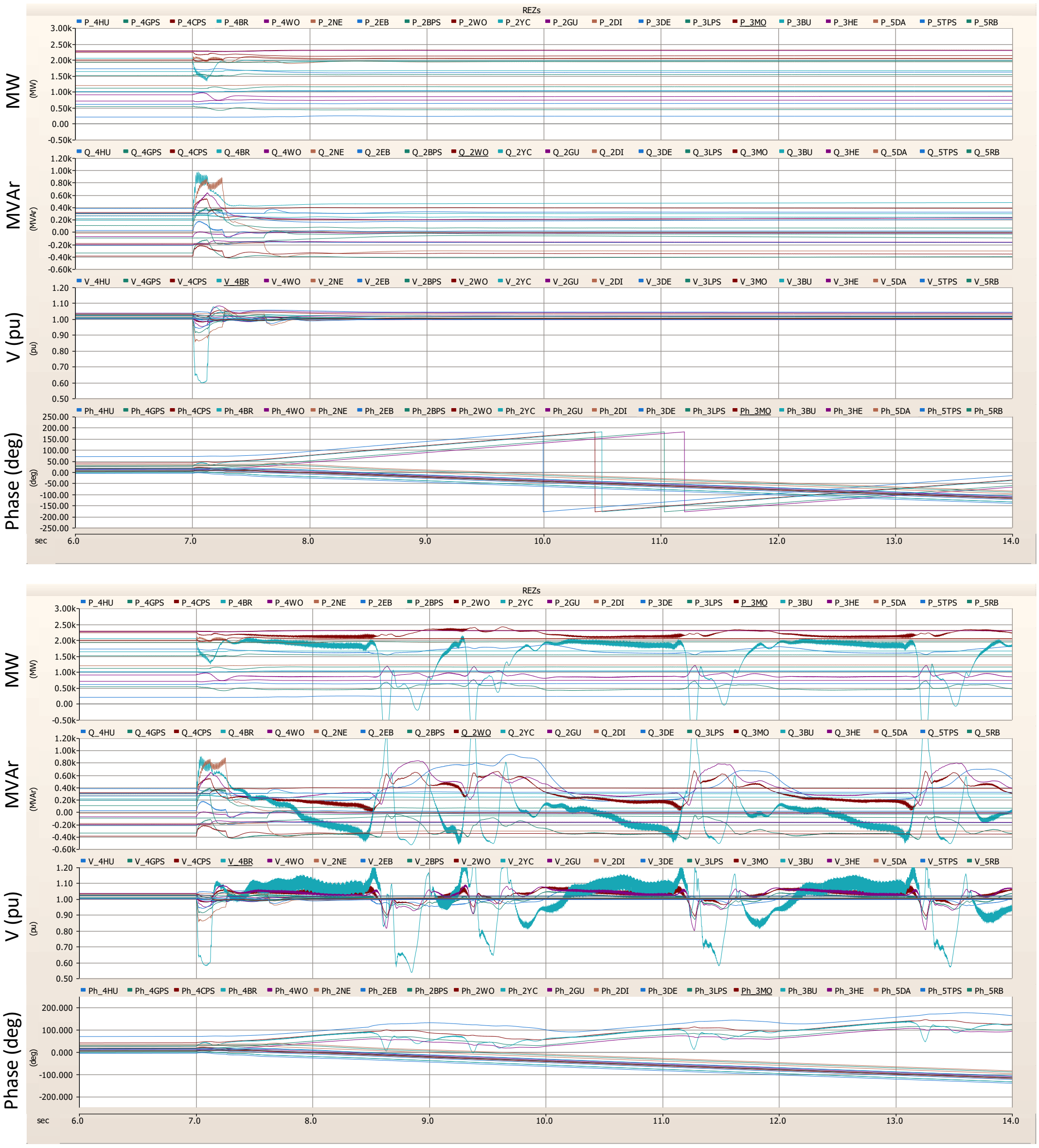


Figure 51 Braemar REZ during high-demand islanding scenario, with filter caps off (top) and on (bottom)

This is an important recognition that modern GFM technology is not a panacea – it is an inverter with a control system subject to instabilities. Care must always be taken in both the control system and filter network design, avoiding the potential for uncatered resonances to fall within the primary control bandwidth.

It is worth noting that GFL devices also interacted strongly with this resonance, but had an even less controlled response, with the system quickly reaching voltages which saw the GFL plant trip on overvoltages. An example is shown below in Figure 52.

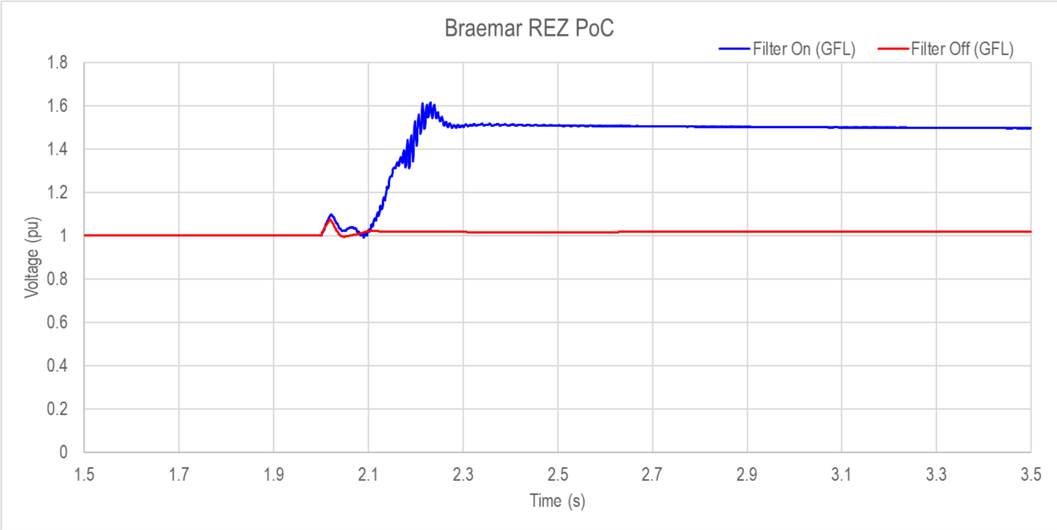


Figure 52 Resonance on GFL devices leading to immediate overvoltage

SVC performance in weak grids

In establishing the 2034 high-demand model, SVCs were used placeholders for some network dynamic reactive plant to ensure the case could reach its proper initialisation state and voltage collapse could be avoided.

While using such SVCs in the test system, growing instabilities were observed in a particularly weak and long-radial part of the network. These oscillations appeared to be between a nearby SVC and a large REZ consisting of both GFL and GFM plant. The oscillations appeared without stimulus – that is, there was no disturbance applied, yet the oscillations manifested presumably because of control system interactions (Figure 53).

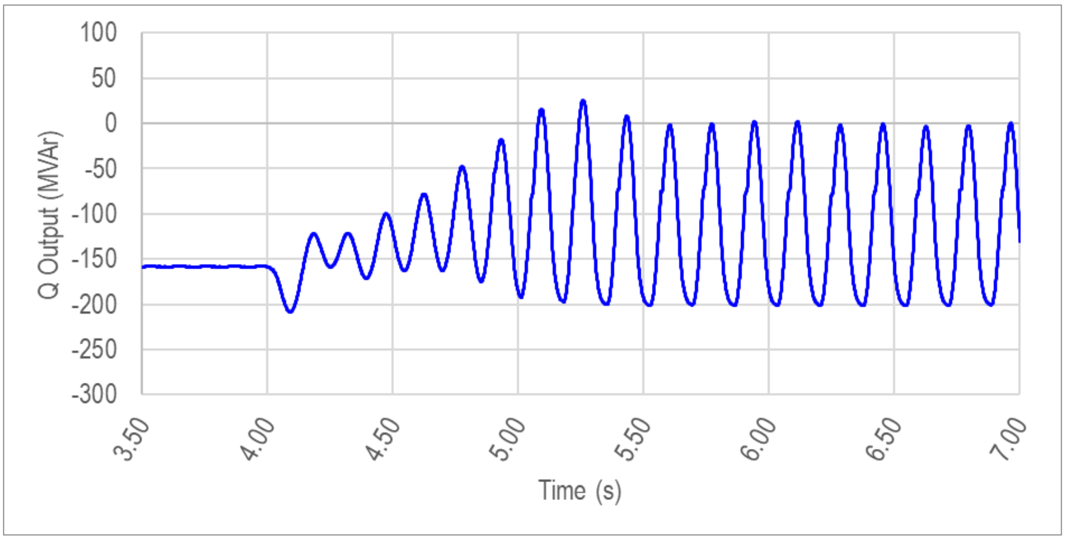


Figure 53 Oscillatory SVC output without presence of disturbances

Investigations showed a strong correlation of the phase relationship between the SVC output reactive power and system voltage, as shown in Figure 54, while the nearby REZ appeared to be almost anti-phase with the voltage oscillations and its reactive power response. While such high-level analysis is not definitive in which party is the “causer” of the issue, the instability was readily remediated when the SVC was removed from service or set into open-loop control.

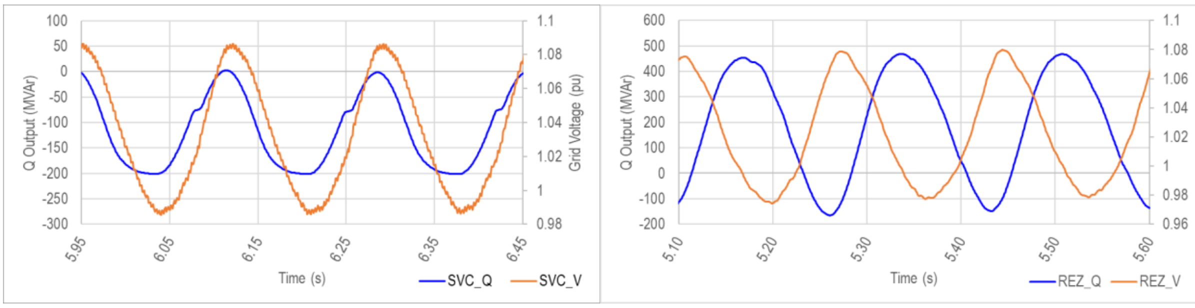


Figure 54 Q & V phase coincidence of SVC and REZ

Although this is a relatively basic example of control system instability, it serves as a reminder that SVCs, despite not having a true “inverter” present, are PLL-dependent closed-loop control systems that have the potential to become unstable in weak grid networks much like other grid-following IBRs. As such, they must be appropriately tuned to cater for such scenarios.

4.4 Transferability of findings to PDT domain (Milestone 4)

The previous chapters detailed some of the EMT studies conducted to assess the different system services needed change as the grid evolves – in this section, this evaluation is extended to positive sequence phasor domain transient (PDT) modelling/analysis. EMT domain modelling allows for detailed representations of the network dynamics as well as the controls (and relevant mechanical and electromagnetic equations of the physical components) of the various devices connected to the grid. Analysis using the high fidelity EMT models can uncover the interactions and responses of these devices and the network across a large range of frequencies – capturing the fast transient behaviour as well as slower control responses. However, there are certain challenges with EMT modelling –

- Additional data requirement: Since EMT models can represent the devices in detail including the faster transients, controls operating in the faster ranges need to be modelled depending on the study and the timeframe of interest. This can result in requiring more data in terms of control structure and/or parameters. For devices existing in the network, if the modeler already does not have these data, coordination with multiple parties including equipment manufacturers and project developers/operators may be necessary to collect these data. If the device controls are updated after the commissioning, for example via a software/firmware update, some of these changes may need to be reflected in terms of updated models. Hence, additional efforts may be needed to obtain and maintain accurate data for all the connected devices.
- Computational burden: EMT simulations can be computationally intensive compared to PDT, since the EMT models are more detailed compared to corresponding PDT models resulting in more differential/algebraic equations that need to be solved during the simulation. Another factor that contributes to the high computational burden of EMT simulations is the smaller timestep needed to ensure that the faster dynamics are accurately captured.

These two factors make EMT modelling and analysis of a large network challenging. In such cases, PDT modelling/simulations may be utilized to estimate the system response.

Note, due to the simplified modelling in PDT, certain aspects cannot be fully captured – any behaviour faster than ~10-15 Hz (around nominal frequency) are not expected to be accurately represented in PDT simulations. Further, since typically the PDT models perform analysis in positive sequence domain, any behaviour related to three-phase unbalance, for example, unbalanced fault, is also not expected to be accurately represented. Despite these design constraints, due to the ease and lesser computational burden of performing PDT simulations there is still value in considering PDT analysis for network-wide simulations and for studying the slower dynamics, and PDT remains an important tool for power system studies.

This chapter describes the efforts undertaken to evaluate the applicability PDT simulations to capture and study the different grid services needed as the grid changes. The particular services under focus here are similar to the ones considered for EMT modelling and simulation aspect in this stage – such as fault current magnitude and fault response and fast voltage control (to the extent possible to capture in PDT). The initial effort is to perform this analysis on a smaller network that is as close as possible to the system considered for the EMT studies in this report – this system is chosen to highlight the similarities and contrasts between the two simulation domains for similar system. As a further effort, the synthetic NEM network used by EPRI previously for topic 2 research to assess these grid services is used. This is, compared to the reduced network, a much larger network and is selected so that the impact of system size (in terms of scaling) and topology is captured.

4.4.1 Matching the positive sequence model

For the matching PDT model, the original load-flow network case data (RAW files) used to develop the EMT cases are chosen as the start point for PDT model. This includes the new synchronous condensers and REZ generators added to the system. Here, similar to the EMT studies, base 2024 and future 2034 cases present the two ends, with cases corresponding to 2027 and 2030 as additional intermediate sensitivities. For each chosen year, two cases – corresponding to low and high demand cases are considered. Including the original and added buses (for REZ generators, for example), this is a 76-bus system. The demand (active power) for each of these cases is given in Table 16.

Table 16 Cases considered for the matching PDT simulations

CASE YEAR	CASE HIGH/LOW DEMAND	DEMAND
2024	Low	8 GW
	High	30 GW
2027	Low	8 GW
	High	33 GW
2030	Low	8 GW
	High	36 GW
2034	Low	8 GW
	High	36 GW

These cases match with the EMT case in terms of the generator retirements and new REZs considered in the future years, and in general, the share of IBR MVA connected compared to the synchronous machines increases in the future years considered. Table 17 and Table 18 give the share of synchronous generator and IBR active powers and MVA connected in these cases for low demand and high demand cases, respectively. Within IBRs (REZs), similar to the EMT case, an equal division between solar PV, wind and BESS units are considered, except for a few cases of specific projects.

Table 17 Resource mix for the low demand PDT cases

YEAR	SYNCHRONOUS GENERATOR PGEN	IBR PGEN	SYNCHRONOUS GENERATOR MVA	IBR MVA
2024	55%	45%	51%	49%
2027	42%	58%	49%	51%
2030	38%	62%	46%	54%
2034	31%	69%	44%	56%

Table 18 Resource mix for the high demand PDT cases

YEAR	SYNCHRONOUS GENERATOR PGEN	IBR PGEN	SYNCHRONOUS GENERATOR MVA	IBR MVA
2024	55%	45%	33%	67%
2027	38%	62%	25%	75%
2030	35%	65%	23%	77%
2034	28%	72%	21%	79%

For representing the REZs, the load-flow cases are modified to replace REZs represented by a single generator with a more detailed representation with generators corresponding to solar PV, wind and BESS IBRs represented as separate generators, each with their own step-up transformer. The parameters for the step-up transformer and line section joining the individual IBR to the POI are based on the REZ model used in the EMT studies.

PDT dynamic data

In terms of the dynamic data, the dynamic data for the generators present in the original case is available in PSS®E dyr format from the original case. These use library models from PSS®E for the generators and synchronous condensers. Similarly, for the new synchronous condensers, the PSS®E library models are used and parameters are based on the corresponding parameters in the EMT model.

For the added solar PV/BESS hybrid and Type 4 wind devices, a combination of following models are used:

- Solar PV: represented by generic renewable generator/electric/plant models (REGC, REEC, REPC) from PSS®E library
- Wind Type 4: represented by generic renewable generator/electric/plant models (REGC, REEC, REPC) from PSS®E library
- BESS acting in GFL mode: represented by generic renewable generator/electric/plant models (REGC, REEC, REPC) from PSS®E library
- BESS acting in GFM mode: publicly available GFM model published by EPRI – in newer PSS®E versions, generic models to represent GFM based on droop – REGFM_A1 and virtual synchronous machine (VSM) control – REGFM_B1 are available. However, for this project a generic GFM model published by EPRI – GNRGFM [41] is used. This model, available as a DLL, can represent the same controls structures described by the two

models available as library models in newer PSS®E version but also has additional capabilities not currently implemented in the library models. Further, this model can be used in some of the older versions of the software as well.

For hybrid plants, the generators corresponding to the different sources (PV, BESS) are represented as separate generators.

For each of these devices, the generic PDT models (as well as generic EMT models) have multiple flags that determine the services provided by that device and the control structures that are used. Further, while the PDT models can usually represent the general trends of behaviour exhibited by an EMT model for the same device, especially for the slower dynamics, the exact match depends on what flags and parameters are selected to make the PDT model structure and functions as close to the corresponding EMT model as possible.

For each of the devices, a voltage step and a frequency step response in a single machine infinite bus system is compared between the corresponding EMT and positive sequence models to ensure the positive sequence model flags and parameters that approximate the behaviour of the EMT model. The comparison of the voltage and frequency response is provided below for solar PV (Figure 55 and Figure 57), type 4 wind model (Figure 58 and Figure 59), GFL BESS unit (Figure 60 and Figure 61) and GFM BESS unit (Figure 62 and Figure 63). These plots correspond to SCR=3 and X/R=10 infinite source, and 0.05 pu voltage dip and 0.5 Hz frequency dips are applied at the infinite source for the voltage and frequency step tests, respectively.

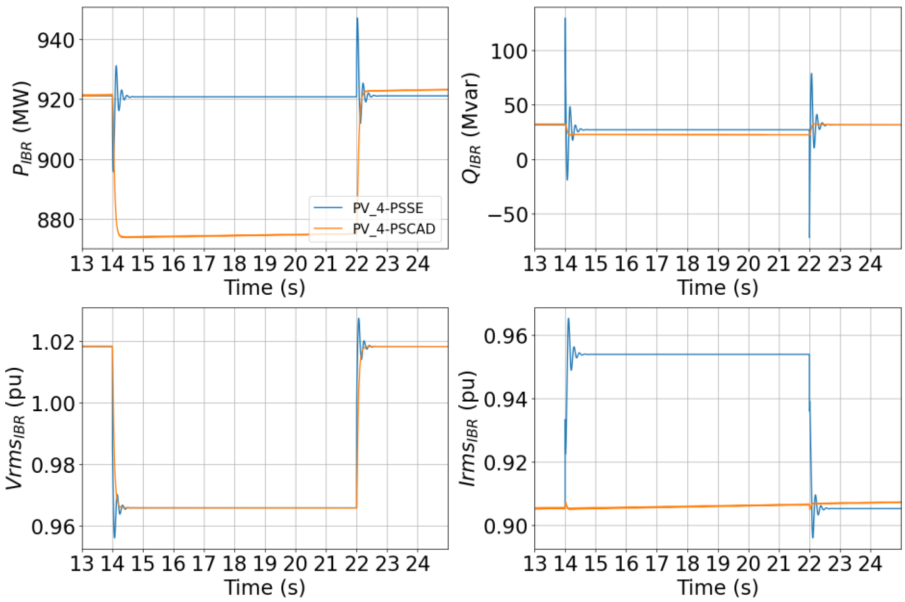


Figure 55 Voltage step response of solar PV EMT and PDT models

Notice, in Figure 55 comparing the voltage response of solar PV EMT and PDT models, EMT model exhibits a drop in active power when the voltage drops whereas it stays relatively constant for the PDT model. This example illustrates how the differences in model structure can cause a difference in the response. In this case, this difference in behaviour is due to the differences in DC-side models. The EMT model includes representation of some of the DC-side dynamics, and the active power is controlled to achieve a constant DC voltage, however, a constant current model is used for the solar PV module (as opposed to detailed modelling of solar panel that may involve controls such as MPPT). On the other hand, the PDT model does not have a DC-side representation (the generic renewable models REGC available in the PDT software packages do not include this representation). This can be visible in Figure 56, where the D-axis current reference in the EMT model using DC voltage control and constant active power control strategies is plotted – the control in the PDT model would be closer to the constant active power control which tries to increase current injected into the network to maintain AC-side active power output, whereas the control implemented in the EMT model results in a relatively-constant current maintained for this disturbance. Note, this difference in the models can result in a difference in behaviour in PDT and EMT studies during periods of voltage changes, such as the voltage sags and swells during faults.

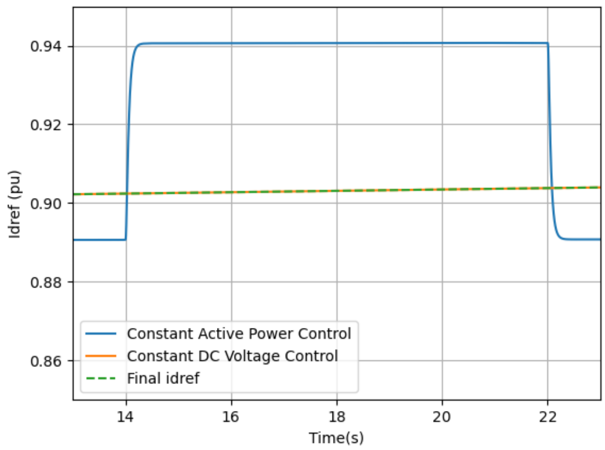


Figure 56 D-axis current reference in EMT model for constant active power and constant DC voltage control strategies

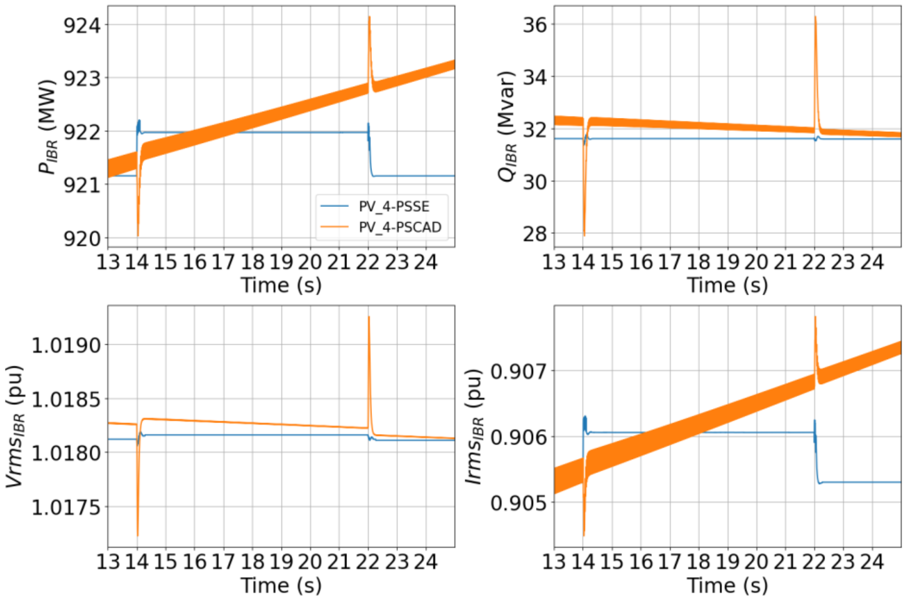


Figure 57 Frequency step response of solar PV EMT and PDT models

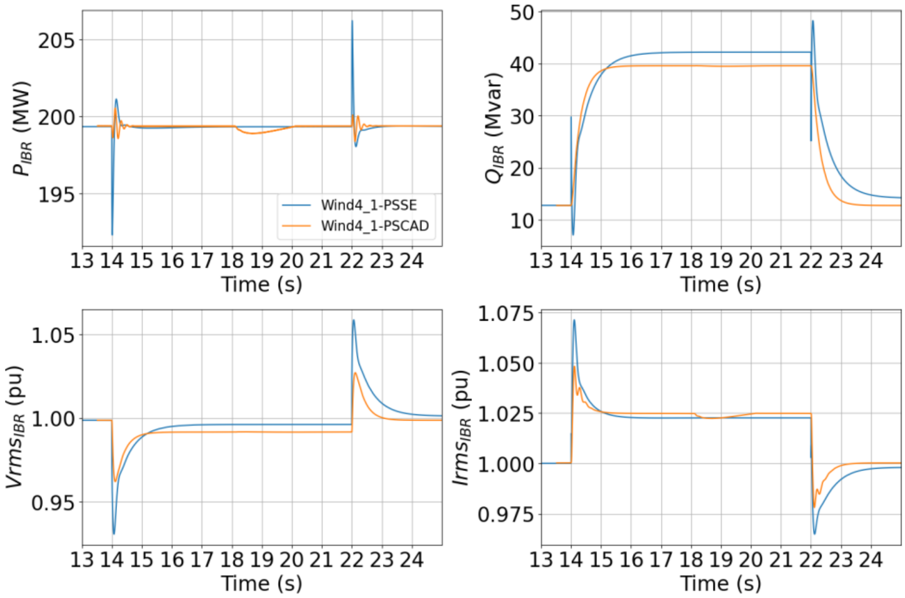


Figure 58 Voltage step response of type 4 wind EMT and PDT models

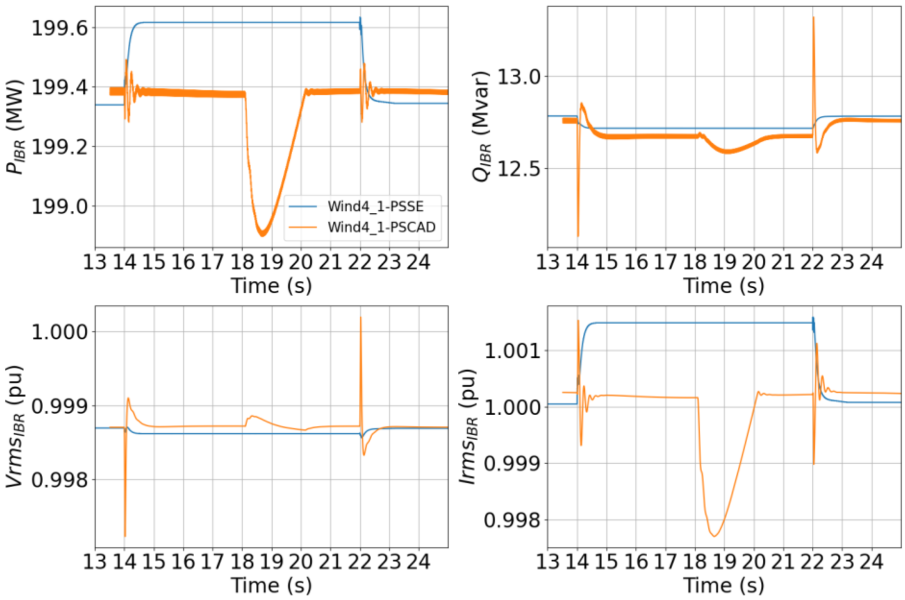


Figure 59 Frequency step response of type 4 wind EMT and PDT models

Some of the differences in Figure 58 and Figure 59, for example at 18s seem to be due to the DC-side representation that the PDT models do not have.

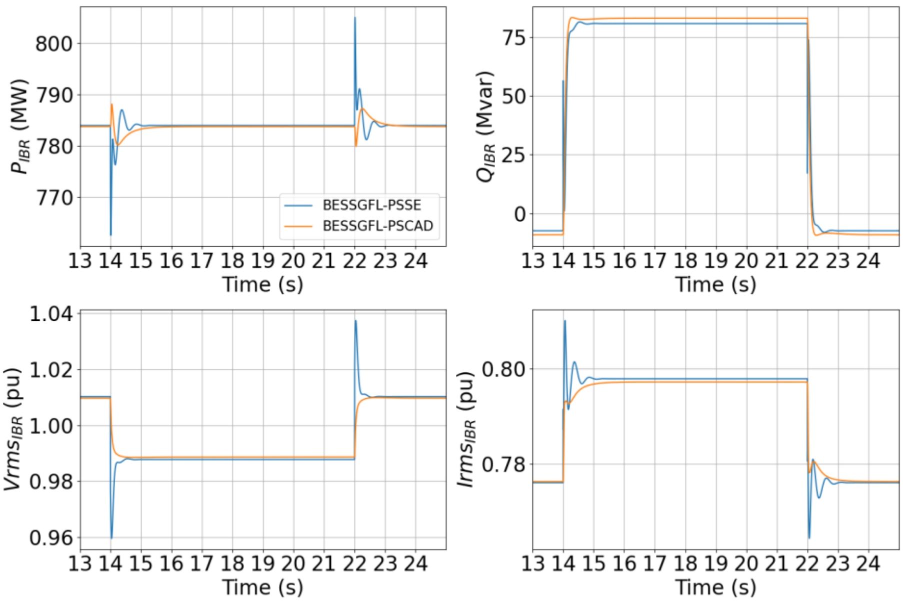


Figure 60 Voltage step response of the BESS operating in GFL mode for EMT and PDT models

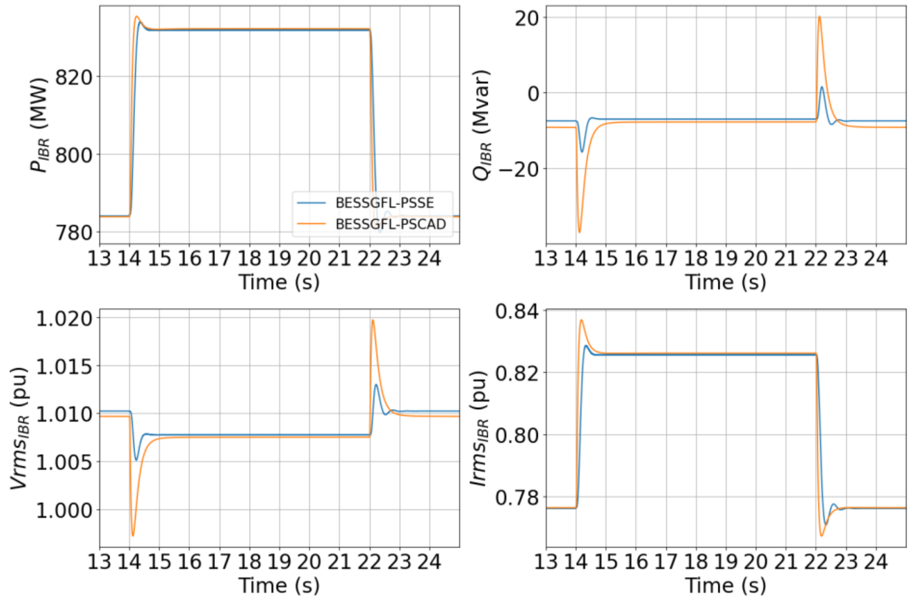


Figure 61 Frequency step response of the BESS operating in GFL mode for EMT and PDT models

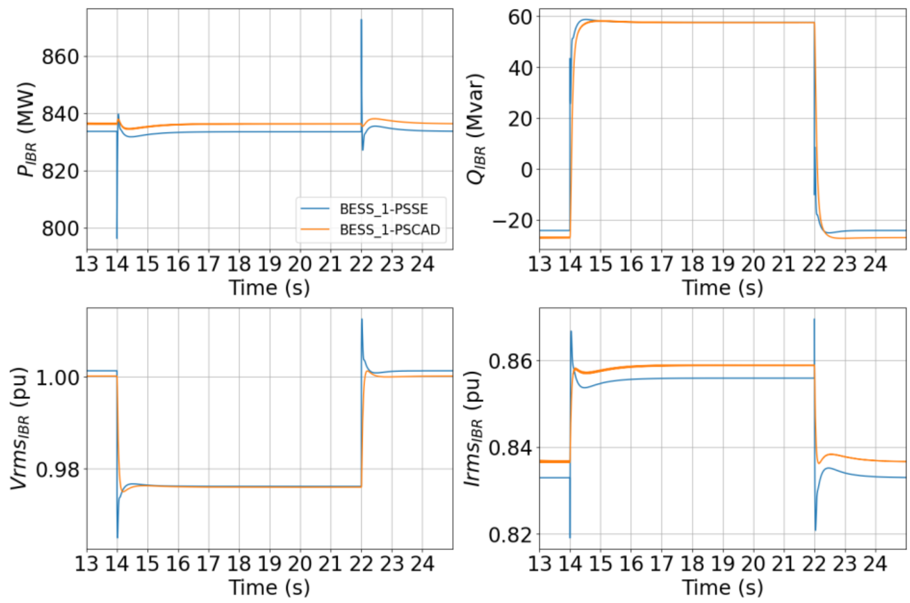


Figure 62 Voltage step response of the BESS operating in GFM mode for EMT and PDT models

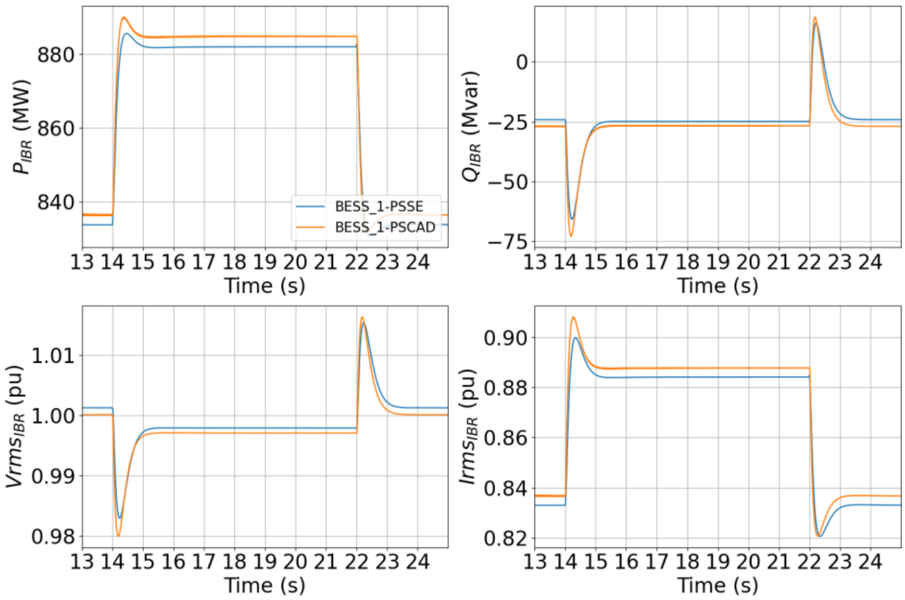


Figure 63 Frequency step response of the BESS operating in GFM mode for EMT and PDT models

Since two control modes are used for representing BESS devices, it may be insightful to compare their response together. For this, in the same single-machine infinite bus setup used, the responses from the BESS for the GFL and GFM PDT parameterizations are compared in Figure 64. It is observed that at least in terms of the responses of frequency and voltage step tests, the overall trends in the response are fairly similar.

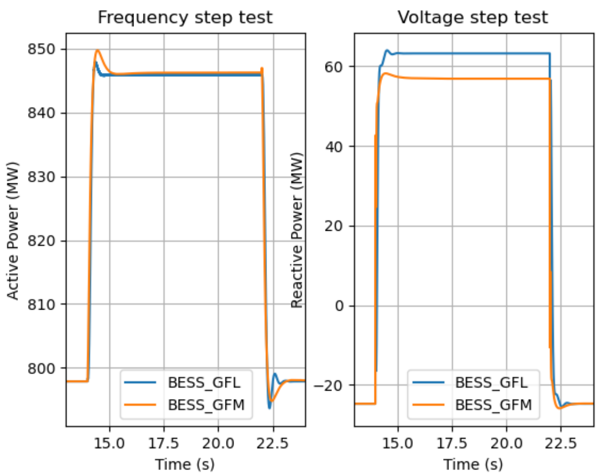


Figure 64 Comparison of BESS in GFL and GFM modes

In the figures comparing the EMT and PDT model response, the overall trends of behaviour between the EMT and PDT models are similar, however, a perfect match is not expected, since the exact model structures for the EMT and PDT models do contain differences, and especially for the very fast dynamics. Further, this does not mean that improvements are not possible to the PDT models and parameterizations utilized. The tests performed here primarily focused on matching the models at a single operating point using the voltage step and frequency step tests. A future effort may look at better benchmarking EMT and PDT model performances by including testing at multiple operating points and a larger set of disturbances. Due to the different characteristics of EMT and PDT simulation domains, and using existing generic PDT models, there are expected to be differences in the model structures of the EMT and PDT models.

Another aspect that can be further studied in the future are the impacts of DC-side controls on the device behaviour and what aspects for each device may be important to model. Currently, in PDT most (if not all) generic models for renewable energy devices do not include any representation of the DC side dynamics, and depending on the models and parameters used in the EMT domain models again the level of detail in representing the DC side dynamics and controls can vary.

PDT dynamic simulations

The PDT models representing the IBR devices are added to the dynamic model of the matching PDT circuit. The fault locations are selected to be the same as the EMT case, one line in each area and an additional case of fault followed by tripping all lines connecting the two buses resulting in islanding are considered. These are provided in Table 19.

Table 19 PDT matching network fault cases

FAULT CASE	VOLTAGE LEVEL	NEAR BUS NUMBER	FAR BUS NUMBER	DURATION
Area 2	500 kV	224	225	0.06s/0.08s
Area 3	500 kV	305	303	0.06s/0.08s
Area 4	275 kV	410	408	0.12s/0.25s
Area 5	275 kV	5041	507	0.12s/0.25s
Area 4 – trip all lines between the fault buses	275 kV	415	416	0.12s/0.25s

Note, even though the lines chosen for applying the faults are based on the EMT case studies, while unbalanced 2 phase to ground faults are applied in the EMT domain, balanced faults are applied for PDT simulations. This is because PDT simulations are often performed in positive sequence domain, where unbalanced faults cannot be accurately represented. However, balanced faults with high impedances are considered to approximate the higher positive sequence fault voltages during unbalanced faults. Particularly, each of the fault impedances were selected so that the fault voltages were approximately 0.4-0.45 pu – the selection was made based on the 2024 low demand case, and the same fault impedances were used throughout the different studies for each fault. All faults were applied by creating a dummy bus on the line at 10% distance from the near end. The different quantities were observed in the network using PSS®E channels such as voltage magnitude, and active and reactive power and generator angles.

Low demand fault cases

In total, 8 low demand cases were considered in this case study – low demand cases corresponding to the four-year cases, 2024, 2027, 2030 and 2034; and for each year, two cases were studied – one with the BESS IBRs modelled as GFLs and one with the BESS IBRs modelled as GFMs. Note, BESSs represent approximately a third of the IBRs modelled. In the power flow solution, a lot of the IBRs were dispatched to absorb large amounts of reactive powers, beyond 30-40% limit, hence, reactive loads of 0.95 per unit were added to the network, and some of the voltage setpoints were increased (in the EMT simulations, for low as well as high demand cases, reactive loads in the cases were set to zero). Further, the reactive power limits in the dynamic models were relaxed to 66% in order to get a stable simulation, but current limits are still applied as before.

Table 20 gives an overview of the low demand fault cases – it was observed that across the different years and GFL/GFM cases, the cases remained stable. Although, in some cases, for the fault and islanding case, bus voltages at a few buses post-disturbance settle to lower voltages (see Figure 65 as an example). In the EMT cases, the corresponding cases were all marked as 'stable' as well.

Table 20 Summary of the low demand case fault studies

YEAR/GFL OR GFM	2024 GFL	2024 GFM	2027 GFL	2027 GFM	2030 GFL	2030 GFM	2034 GFL	2034 GFM
Fault in Area 2	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Fault in Area 3	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Fault in Area 4	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Fault in Area 5	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable
Fault+ islanding in Area 4	Stable	Stable	Stable	Stable	Stable	Stable	Stable	Stable

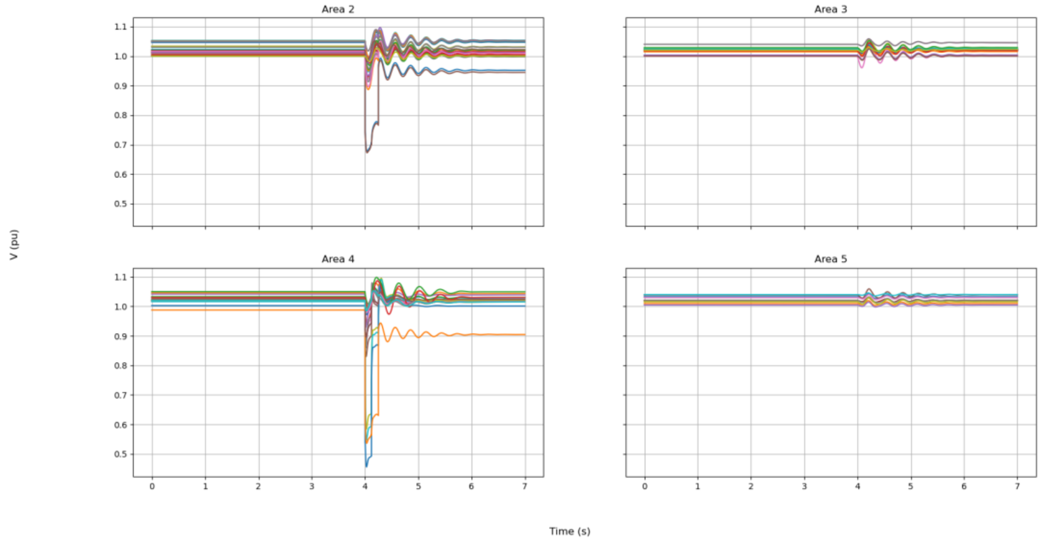


Figure 65 Voltages in the different areas for fault and islanding for the 2027 GFL case

The rest of the section describes some key trends observed:

- In terms of fault voltages, in qualitative terms, all cases have similar fault voltages for the same fault. Small differences can be observed, with the GFM cases having a slightly higher voltages during the fault than the corresponding GFL cases, and the later-year cases having a slightly larger voltages during the fault. One example comparing the voltages at the fault location for the fault in area 2 is plotted in Figure 66. Here, the fault is applied at 4.0s, the near end portion of the line is disconnected at 4.06s and the far end is disconnected at 4.08s.

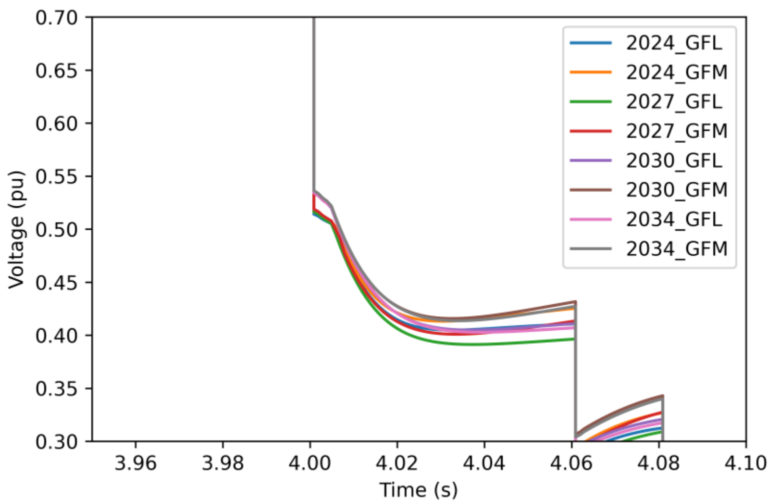


Figure 66 Fault voltages for fault in area 2 for the different low demand cases

- The fault currents are similar across the different year and GFL/GFM cases with small differences between them, for example, the fault currents for the fault in area 2 are plotted in Figure 67. For different faults, the maximum fault currents (at the start of the fault) are ~4-7 kA, with a difference between the different year and GFL/GFM cases being within ~0.4-1 kA.

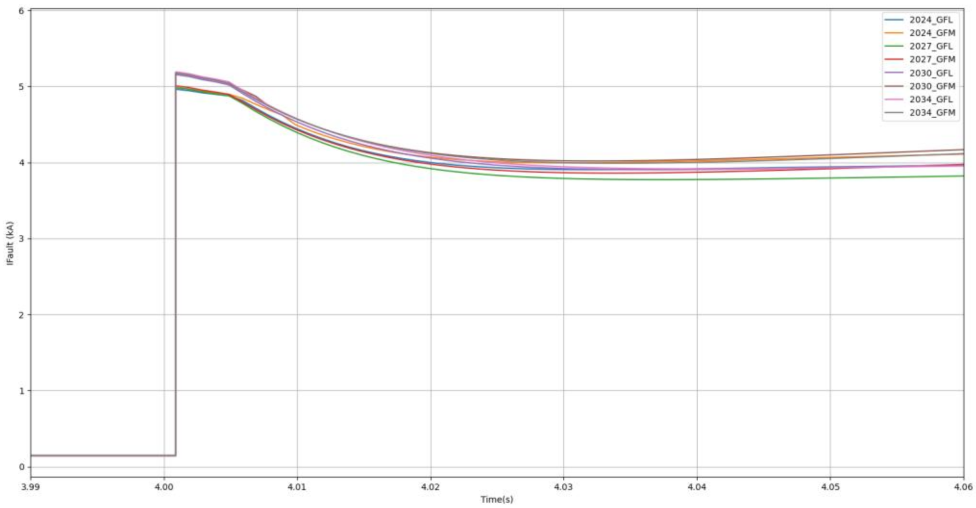


Figure 67 Fault currents for the fault in area 2 for the different low demand cases

- Looking at system-wide voltages, the voltage dips during the fault are observed to be most severe in the area with the fault, with a few buses in neighbouring areas also experiencing some voltage dips during the fault. The duration of voltage dips is similar between the different cases.
- After a fault is cleared, there are overvoltages observed throughout the network. Again, these overvoltages are largest in the area with the fault, and lesser in other, distant areas. Though, some overvoltages are observed even for buses in distant areas at which during the fault there was no significant voltage dip. These behaviours can be observed from Figure 68.

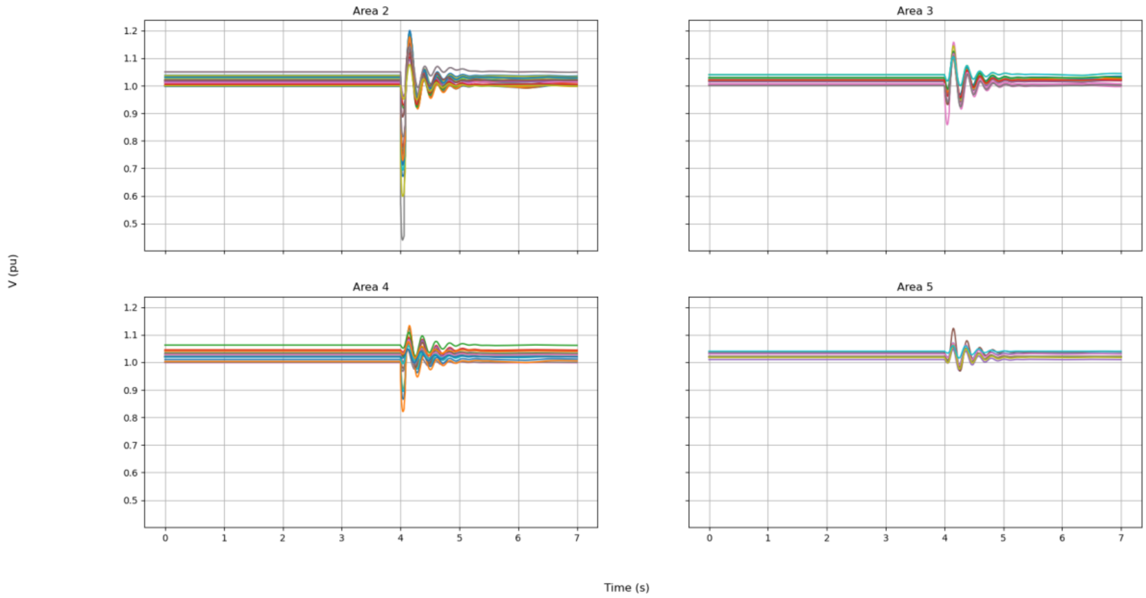


Figure 68 Voltages across the network for the fault in area 2 for 2034 GFM case

- The durations of the voltage dips during the fault remain similar across the years and across GFL and GFM cases. However, the overvoltages tend to be worse for the cases corresponding to later years, and for GFL cases, as observed in Figure 69.

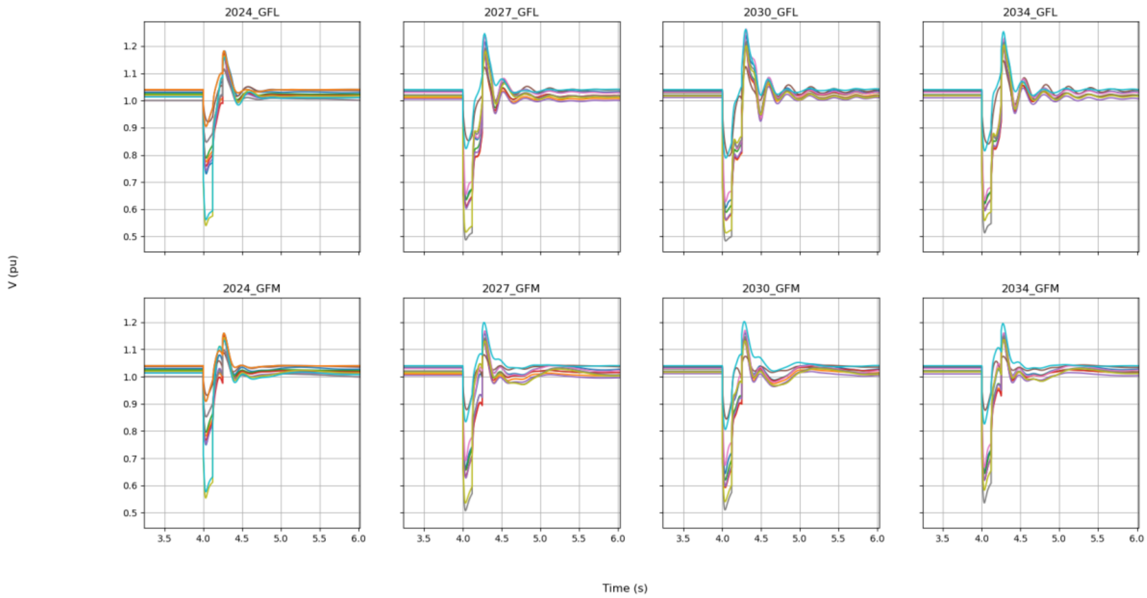


Figure 69 Group 5 voltages for a fault in group 5 across the different year and GFL/GFM cases

- After the fault clears, oscillations are observed in the voltages throughout the network, and these oscillations are more pronounced and slower to damp out in the later years and with BESSs operating in GFL mode. Figure 68 shown before is for 2034 case with BESSs operating in GFM mode, a similar plot for the 2034 case with BESSs operating in GFL mode is plotted in Figure 70. To further illustrate this difference voltages at the terminal of one of the BESSs close to the fault in area 2 is plotted in Figure 71. During the fault, the differences in the voltages are smaller, whereas after the fault is cleared the difference is more pronounced in terms of the difference in damping the oscillations. Note, a system strength analysis using EPRI Grid Strength Assessment Tool [42] assuming an injected MW value of 300.0 at this BESS location (corresponding to Pmax of the BESS device) yielded an SCR of ~9.5 and X/R ratio of approximately ~6 at this location, so this is not a very weak part of the network. The GFL and GFM modes were found to respond similarly in single machine infinite bus voltage and frequency step changes (though the tests were conducted at a different SCR and X/R ratio) (Figure 64), but their behaviour in the network during the disturbance shows greater differences – the reason behind such differences, and the characterization tests needed to capture such differences could be further explored in future efforts. Topic 2 research explores some aspects of characterization/understanding the oscillatory behaviour with high percentage of IBRs (the roadmap for this topic can be found at [43] and the research from stage 3 can be found at [44]).

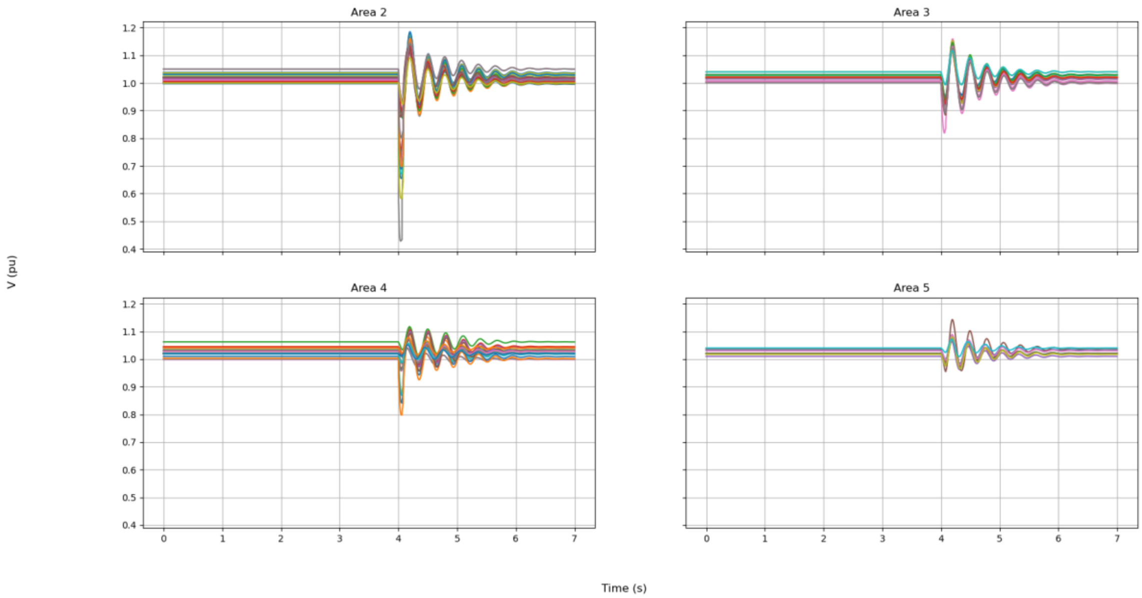


Figure 70 Voltages across the network for the fault in area 2 for 2034 GFL case

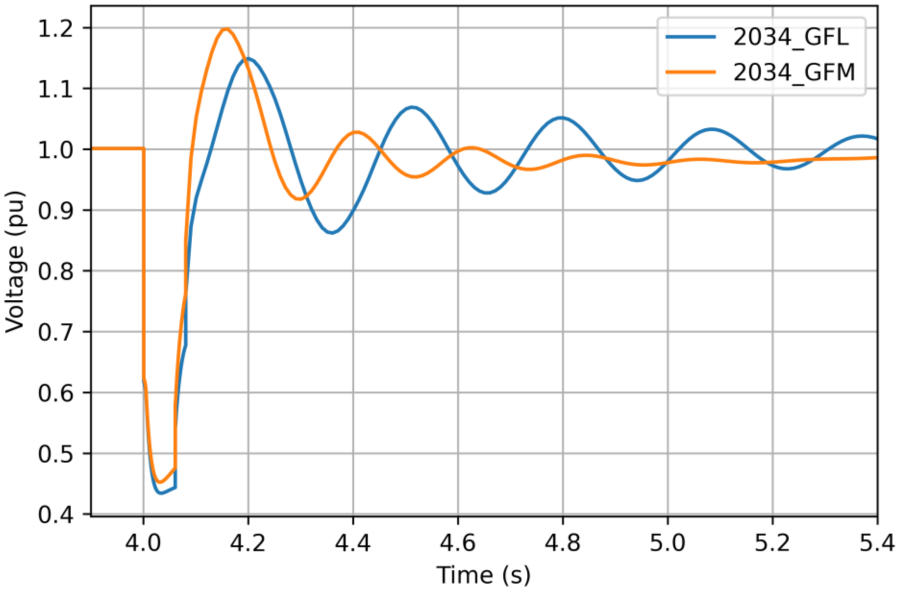


Figure 71 Voltage at the terminal bus for a BESS near the fault in area 2 for the 2034 GFL/GFM cases

- In terms of the changes to active and reactive powers supplied by the different generators, it is observed that the additional reactive power during the fault is primarily supplied by the generators and IBRs in the area with the fault. Generators (synchronous and IBR) in other areas do inject additional reactive powers, but it is much less compared to the additional reactive power from the generators in the area with the fault. One example of this is illustrated in Figure 72, which shows the change in the reactive power supplied by the generators in each area during and after the fault. In terms of differences between the cases, the reactive powers supplied by the generators (including synchronous and IBR generators) in the area with the fault tend to reduce in the later year cases (with increased ratio of IBRs to synchronous generators), and GFLs tend to have slightly lower reactive powers injected into the network than the corresponding GFM cases, but these differences are small.

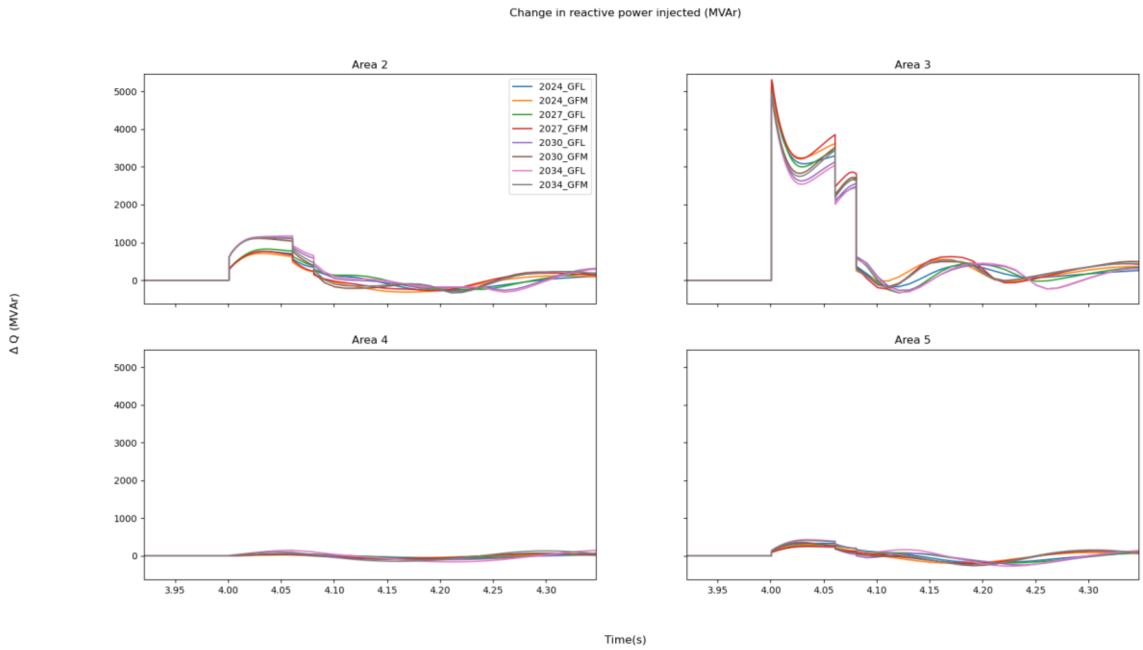


Figure 72 Change in/additional reactive power injection by generators in different areas in response to a fault in area 3 for different cases

- When looking at the response beyond the fault, some oscillations (corresponding to the voltage oscillations) are observed in the reactive powers as well, especially for the GFL cases. These are also observed in the active powers. The changes in the generator active powers and generator reactive powers in each area for a fault in area 2 are plotted in Figure 73 and Figure 74, respectively. Note, these are changes in active and reactive powers compared to the pre-disturbance values, so a negative ΔP does not necessarily mean that the active power is being absorbed.

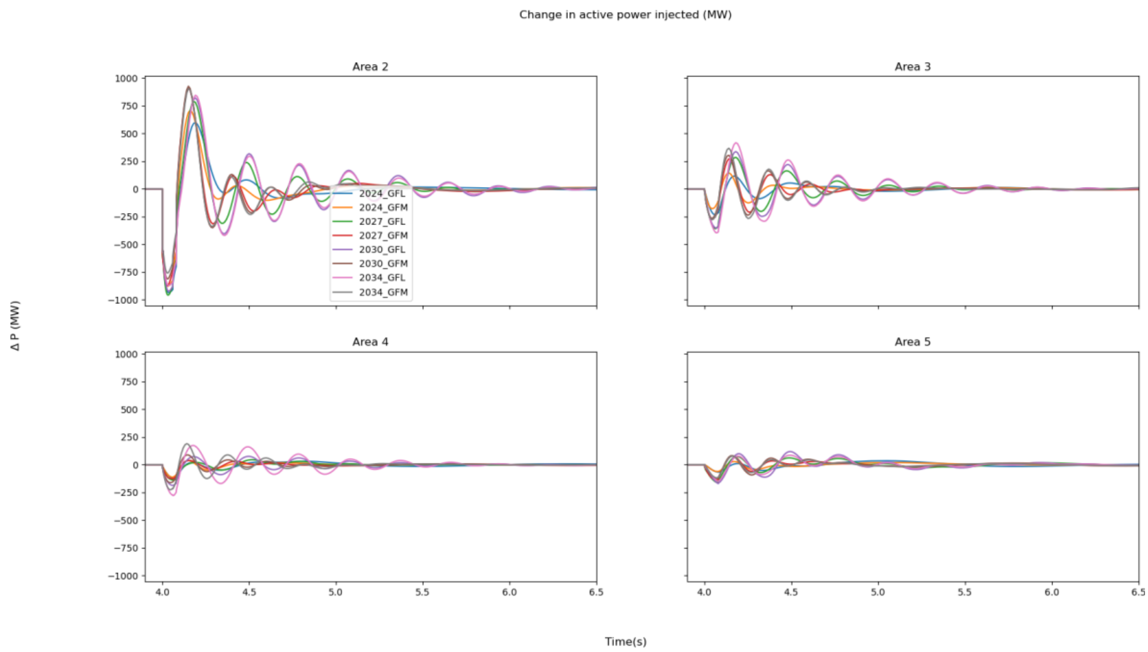


Figure 73 Change in/additional active power injection by generators in different areas in response to a fault in area 2 for different cases

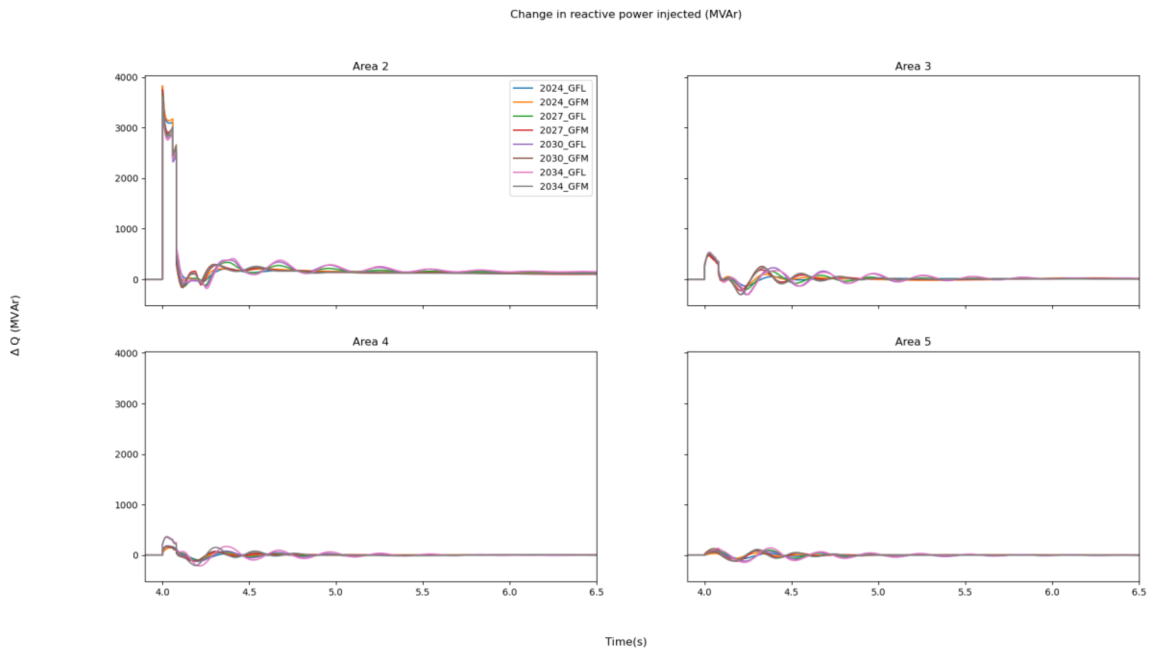


Figure 74 Change in/additional reactive power injection by generators in different areas in response to a fault in area 2 for different cases

- In terms of the phase angle change during the fault observed at the generators, the phase angle changes in the area with the faults are generally larger, while the generators in the other areas have smaller changes. However, the exact trend also depends on the faults, for example, for the fault in area 3, there are some generators in area 2 that also have a phase change comparable to some of the generators in area 3 (Figure 75), while for another fault (fault in area 4) the phase changes in other areas are minimal compared to the phase changes in the generators in area 4 (Figure 76)

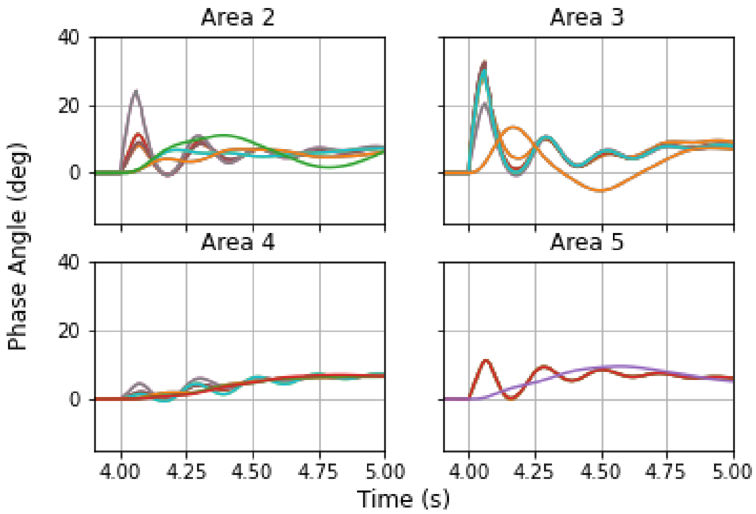


Figure 75 Generator phase angle changes for a fault in area 3 for the 2034 GFM case

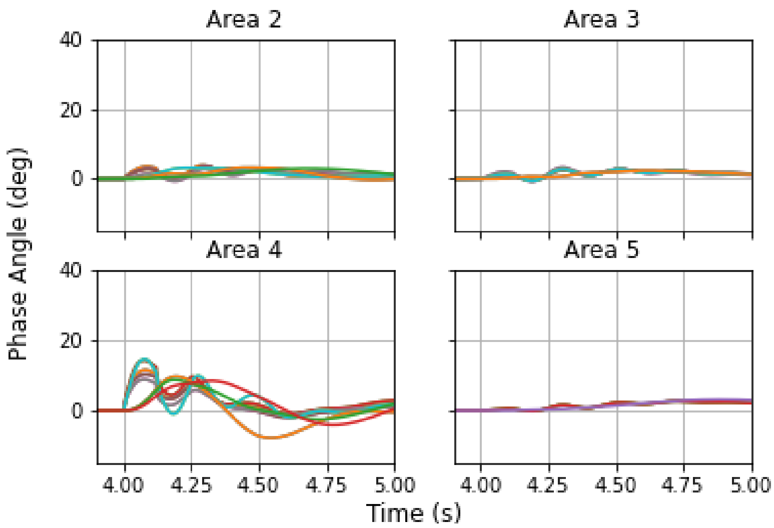


Figure 76 Generator phase angle changes for a fault in area 4 for the 2034 GFM case

- In general, the phase angle changes seem to be larger for the later year cases, and larger for the GFL cases than GFM cases. However, the impact of the case year is more pronounced, as shown in Figure 77.

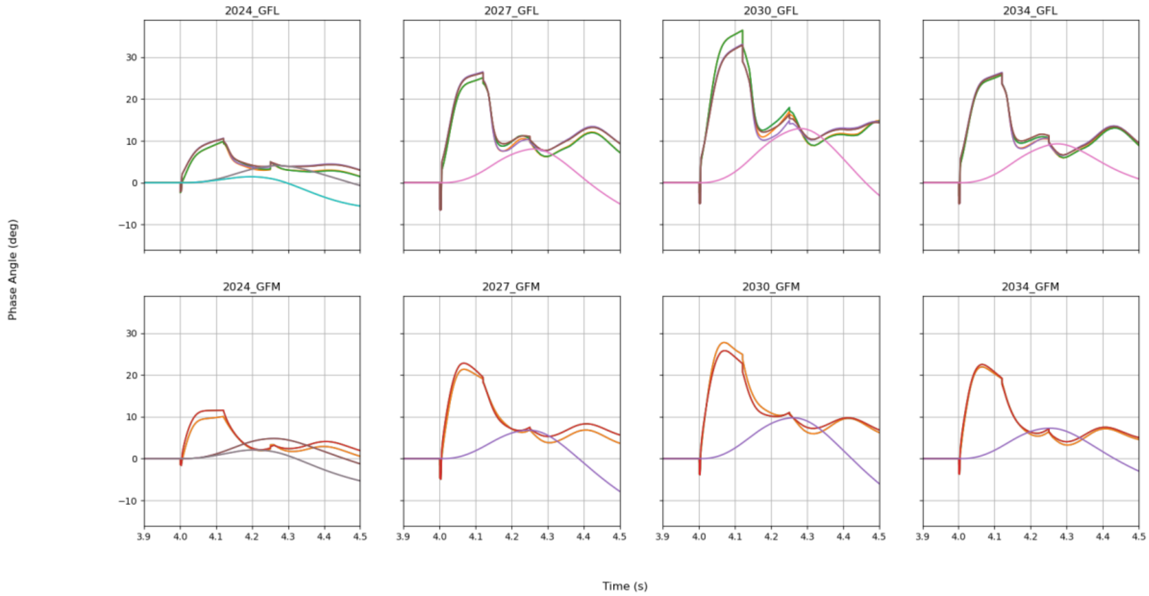


Figure 77 Generator phase angle changes for generators in area 5 for a fault in area 5 across the different cases

High demand fault cases

Similar to low demand cases, high demand cases corresponding to the four years, 2024, 2027, 2030 and 2034 were considered in this case study. For these cases, the reactive part of the loads was kept as 0, since even with a 0.99 lagging power factor, the load-flow solution was not reached. In future, this aspect of the cases can be improved upon. For each year, two cases were studied – one with the BESS IBRs modelled as GFLs and one with the BESS IBRs modelled as GFMs. Note, BESSs represent approximately a third of the IBRs modelled. The same relaxed reactive power limits in the dynamic models as the low demand cases were used.

Table 21 gives an overview of the high demand fault cases – it was observed that unlike EMT cases, the cases with high demand with GFL BESS models showed unstable behaviour for all the fault cases (though a successful flat run was achieved). Even for the cases with GFM BESS models, some of the fault cases resulted in unstable responses (either growing oscillations in the post-fault clearance period or unstable behaviour marked by very low/high voltages and network solution failing), and some cases (fault in area 2 for 2024 and fault followed by islanding for 2024, 2027, 2030 cases) resulted in low voltages in the post-fault clearance period for some buses, indicating potential need for additional reactive power support.

Table 21 Summary of the high demand case fault studies

YEAR/GFL OR GFM	2024 GFL	2024 GFM	2027 GFL	2027 GFM	2030 GFL	2030 GFM	2034 GFL	2034 GFM
Fault in Area 2	Unstable	Stable	Unstable	Stable	Unstable	Stable	Unstable	Stable
Fault in Area 3	Unstable	Stable	Unstable	Stable	Unstable	Stable	Unstable	Stable
Fault in Area 4	Unstable	Unstable	Unstable	Unstable	Unstable	Stable, some poorly damped modes	Unstable	Stable, poor damping
Fault in Area 5	Unstable	Large oscillations before stabilizing	Unstable	Stable	Unstable	Stable	Unstable	Stable
Fault+ islanding in Area 4	Unstable	Stable	Unstable	Stable	Unstable	Stable	Unstable	Stable

The rest of the section describes some key trends observed, and plots are provided if a different trend (compared to the low demand cases) is observed:

- In terms of fault voltages, in qualitative terms, all cases have similar fault voltages for the same fault (including the cases that show unstable behaviour in the post-fault clear period). Similar to low demand cases, small differences can be observed between the different year cases.
- The fault currents are similar between the different year cases for each fault, and different faults have fault currents ranging from 4-8 kA. It is observed that for the same fault, the fault currents are larger for the high demand cases.
- Looking at system-wide voltages, the voltage dips during the fault are observed to be most severe in the area with the fault, with a few buses in neighbouring areas also experiencing some voltage dips during the fault. The duration of voltage dips is similar between the different cases. The same fault impedances as the low demand cases used result in less severe voltage dips compared to the low demand cases.
- After a fault is cleared, the overvoltages are also less severe compared to the low demand cases. Where they do occur, these overvoltages are largest in the area with the fault, and lesser in other, distant areas, similar to the low demand cases. The durations of the voltage dips during the fault remain similar across the years and the overvoltages also tend to be similar across cases corresponding to different years, as shown in Figure 78.

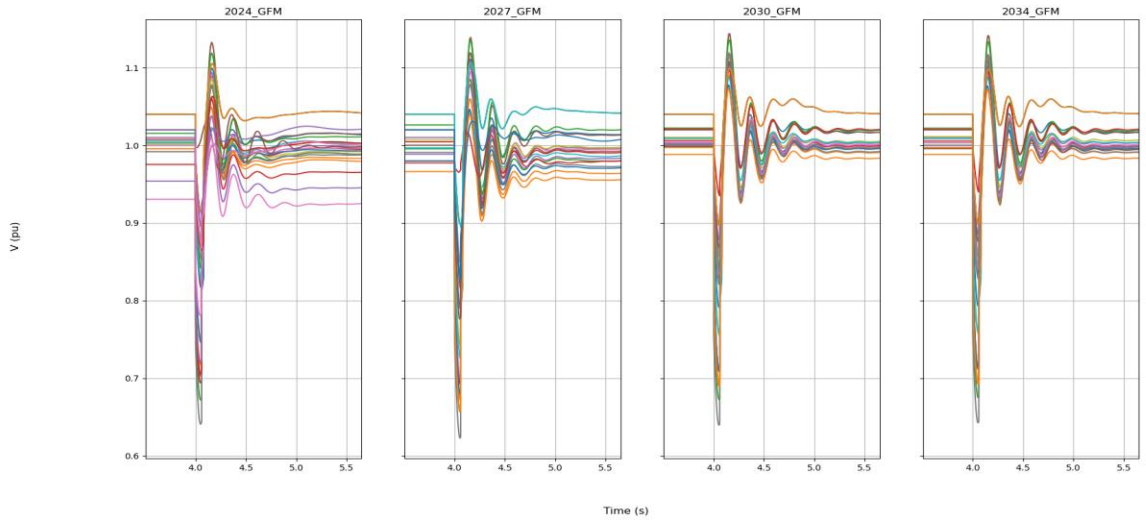


Figure 78 Voltages in area 3 for the fault in area 3 across different cases

- In terms of the changes to active and reactive powers supplied by the different generators, it is observed that the additional reactive power during the fault is primarily supplied by the generators and IBRs in the area with the fault. One example of this is illustrated in Figure 79, which shows the change in the reactive power supplied by the generators in each area during and after the fault. The corresponding active powers are plotted in Figure 80.

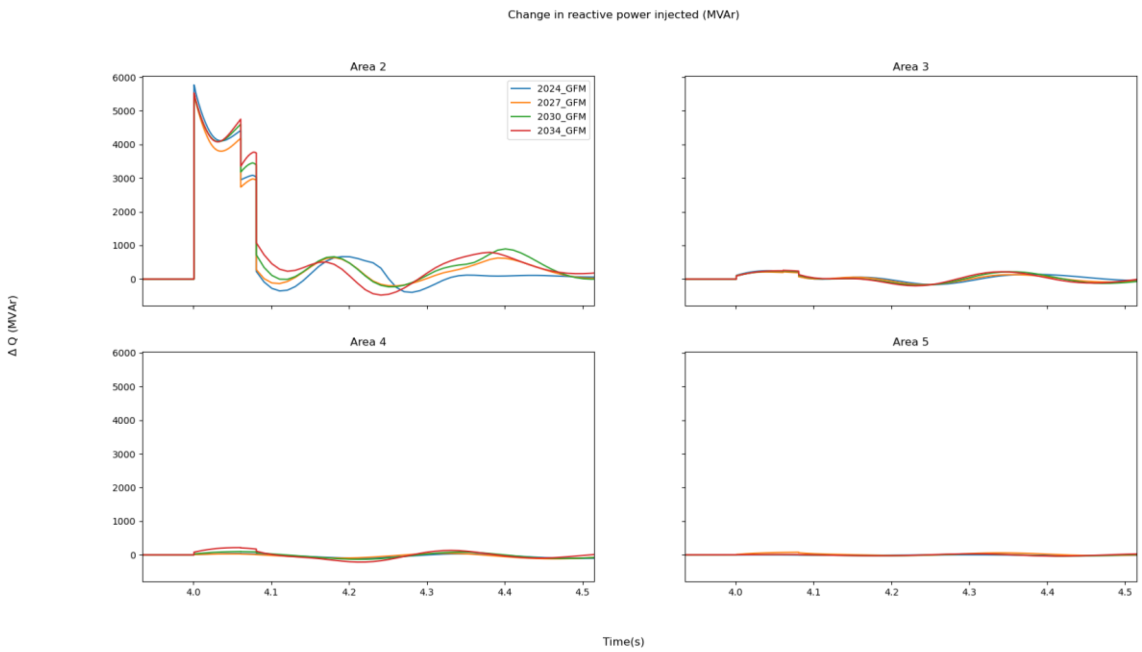


Figure 79 Change in/additional reactive power injection by generators in different areas in response to a fault in area 2 for different cases

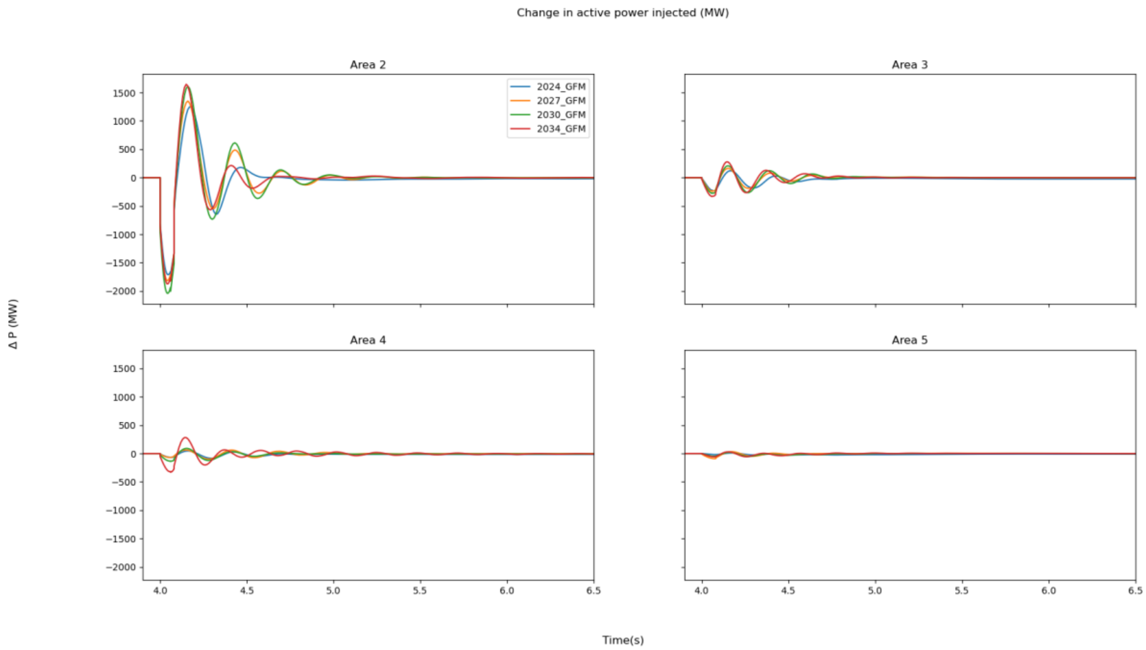


Figure 80 Change in/additional active power injection by generators in different areas in response to a fault in area 2 for different cases

- When looking at the response beyond the fault, the oscillations in active and reactive power are much less compared to the low demand cases (in the low demand cases, GFL cases exhibited larger oscillations, and those cases show growing oscillations/are unstable so not included here)
- In terms of the phase angle change during the fault observed at the generators, similar to the low demand cases, the phase angle changes in the area with the faults are generally larger, while the generators in the other areas have some changes. However, the exact trend also depends on the faults, for example, for the fault in area 3, there are some generators in area 2 that also have a phase change comparable to some of the generators in area 3, while for another fault (fault in area 2) the phase changes in other areas are minimal compared to the phase changes in the generators in area 2. Again, similar to low demand cases, in general, the phase angle changes seem to be larger for the later year cases

From the PDT and EMT cases, there seems to be some differences and some similarities between PDT and EMT responses. The largest difference is in terms of the PDT cases showing unstable behaviour for the fault cases for the high demand cases where the corresponding EMT cases were stable. When dispatch was changed to 100% IBR, again all the fault cases indicated unstable behaviour (regardless of low or high demand) in the form of growing oscillations or network solution being unable to converge in the post-fault condition. This oscillatory behaviour indicates potential converter-related instabilities, but more investigation would be needed to find root causes and multiple factors may also be at play.

While a lot of aspects between the EMT and PDT cases are similar, there are differences as well – one set of differences comes from the different characteristics of the PDT and EMT domain. These include differences such as the differences in network models and presence/absence of the faster dynamics and the absence of negative/zero sequence details in PDT. Some specific differences also exist, for example, the power flow solutions were modified for the PDT simulations from the base network. Due to lack of negative and zero sequence networks, another approximation applied here was to apply a fault resulting in ~0.4-0.45 pu voltage in the dynamic run, but that aspect could also be investigated further. These differences (and potential differences) only highlight the need and importance of improved and increased diligence in matching the PDT and EMT cases across multiple aspects – the steady state or load-flow solution, as well as extensive comparisons of generator and load dynamics under different scenarios and contingencies to identify the region where EMT and PDT simulations match and differ in terms of ranges of load-flow solutions (low/high demand), individual devices connected (for example, increased IBRs).

4.4.2 Synthetic NEM model

After performing the studies for the smaller PDT network, similar fault studies were conducted on synthetic NEM system. This system originally had ~2300 buses and ~256 generators to represent the network on the footprint supplied by NEM network. The work developing the original synthetic network is described in [45], [46] and [47], and this was further modified in previous stages of EPRI's CSIRO funded topic 2 work [48]. Two cases – low and high demand – were selected from the 24 cases developed as a part of the stage 2 work and utilized for testing the fault responses. These cases are based on the broad topology of NSW, VIC, SA, and QLD states. While the original synthetic NEM network also contains TAS representation, it was not represented in detail in the cases modelled in the previous stage reports of topic 2 work, and the same assumption applies here.

Another important factor here is to iterate a similar disclaimer to the reduced network applies to this network as well. While some of the basic topological characteristics are present, this network was constructed using statistically generated data for the lines, transformers etc. and did not include components that were out of service in the base case used for creating the synthetic network (more details in [45], [46] and [47]; and [48]). Further, the network bus names are all obfuscated – hence, new network upgrades are not included in this study.

The low load case was selected to correspond to hour=11 case and has ~12 GW load, while the high load case was selected to correspond to hour=18 case and has ~24 GW load. These cases were created assuming a high renewable resource mix of 34% synchronous generators and 66% GFL IBRs by active power generation (ratios of MVA connected are similar), where most of the synchronous generation is in QNL – where 100% generators in SAU, and 90% generators in NSW and VIC are assumed to be IBRs [48]. This previous stage report also provides for more details regarding the construction of these case and different assumptions. Taking the base case, steps such as voltage optimization were applied to create the dispatches. As discussed in this report, the base cases without any GFM showed small signal oscillations. Hence, GFMs were added in the previous work at locations with low system strength. That case is used as the GFM case for each of the hours selected, and with the GFMs added, the resource mix becomes 28% synchronous generators, 61% GFL and 10% GFMs by connected MVA. GFMs are operated at 0 active power in the power flow (neither charging nor discharging). Note, for this network, area 1 corresponds to New South Wales (NSW), area 2 corresponds to Victoria (VCT), area 3 corresponds to Queensland (QNL), area 4 corresponds to South Australia (SAU), and area 5 (not used) corresponds to Tasmania (TAS). A topological map of the synthetic NEM system is shown in Figure 81.

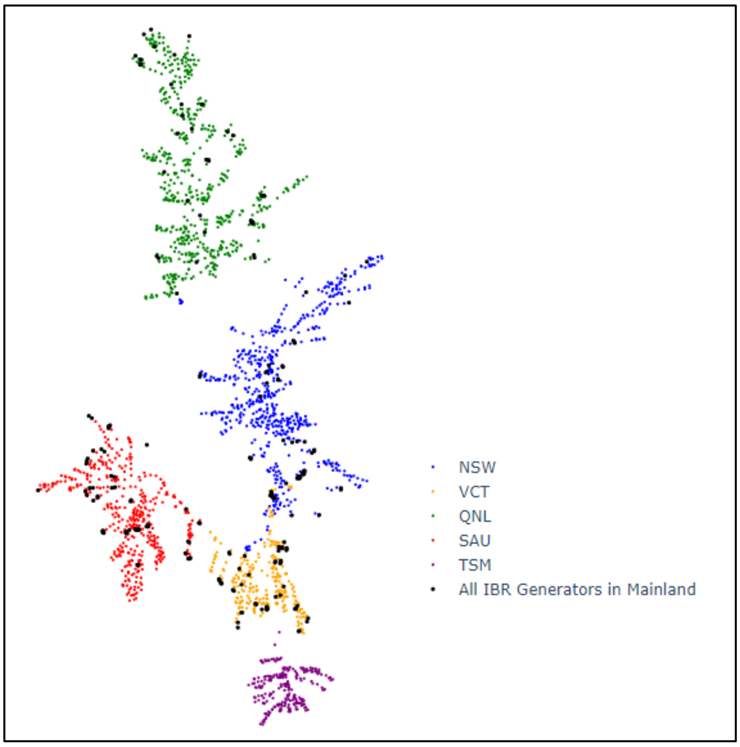


Figure 81 Topological map of the synthetic NEM network

In the dynamic simulations, models and parameters utilized in the stage 2 work [48] were directly used here – the model parameters are available in that report, and the models included the library models from PSS®E 'GENROU', 'ESAC4A' and 'TGOV1' to represent the generator, exciter and governor for the synchronous generators, while IBRs are represented by REGC_C (used in PSS®E v34 here as a user model [49], but in later PSS®E versions this model is available in the PSS®E library), REECCU1 (available in PSS®E model library) for GFLs and EPRI GNRGFM [41] model for representing GFMs. PSS®E v34 was used for this study.

In the dynamic simulations, voltages at buses with 275 kV and above were monitored. For the fault cases, the lines with largest active power flows on lines at/above this voltage level were considered. The details of the faults are given in Table 22. Each fault was applied as a line fault and the fault voltage was ensured to be approximately 0.4-0.45 pu.

Table 22 Synthetic NEM network fault cases

AREA	BUS1	BUS2	KV	FAULT DURATION (S)
1	Bus_1124	Bus_1149	330	0.12
2	Bus_2198	Bus_2199	500	0.1
3	Bus_3602	Bus_3607	275	0.12
4	Bus_4128	Bus_4148	275	0.12

PDT dynamic simulations

The low demand case corresponds to hour=11 case from [48]. In the base case (without GFMs) this case exhibited small signal oscillatory behaviour, as shown in a no-contingency simulation, in Figure 82. After GFMs are implemented, a successful flat run is achieved, and the fault cases are applied to it. High demand (hour=18 case from [48]) achieves a successful flat run even without GFMs, however, poorly damped oscillations are observed after applying the faults, for example Figure 83 shows the voltages after applying fault in area 1 and Figure 84 shows voltages after applying fault in area 3. Different amounts of GFMs added were considered as sensitivity cases – 1840 MVA (indicated in the plots as 'GFM1'), 3534 MVA (indicated in the plots as 'GFM2') and 5348 MVA (indicated in the plots as 'GFM3').

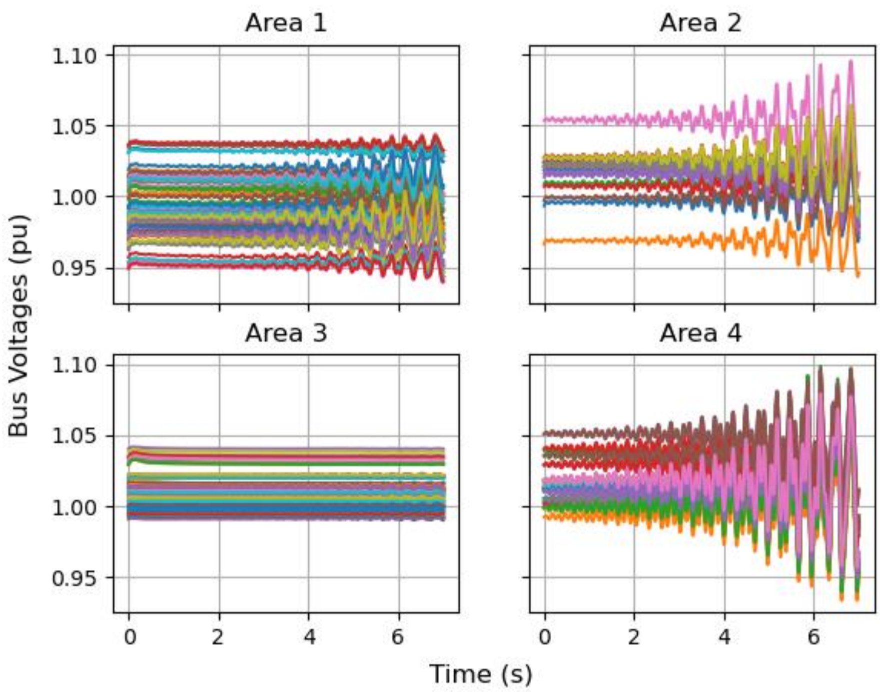


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Figure 82 Voltages in different areas for low demand synthetic NEM network case with no GFMs for a no-contingency run

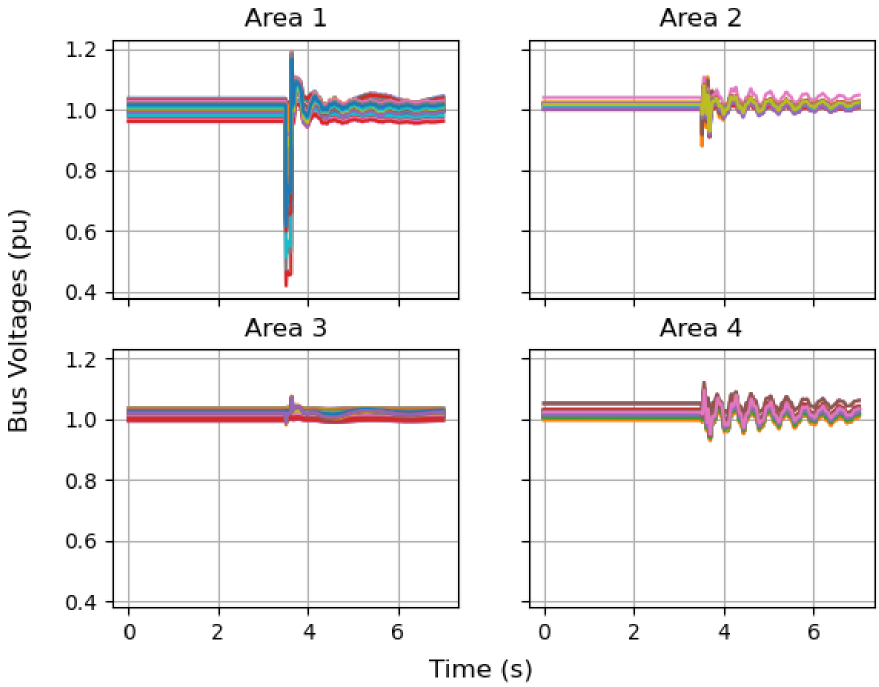

Figure 83 Voltages in different areas for low demand synthetic NEM network case with no GFMs for fault in area 1

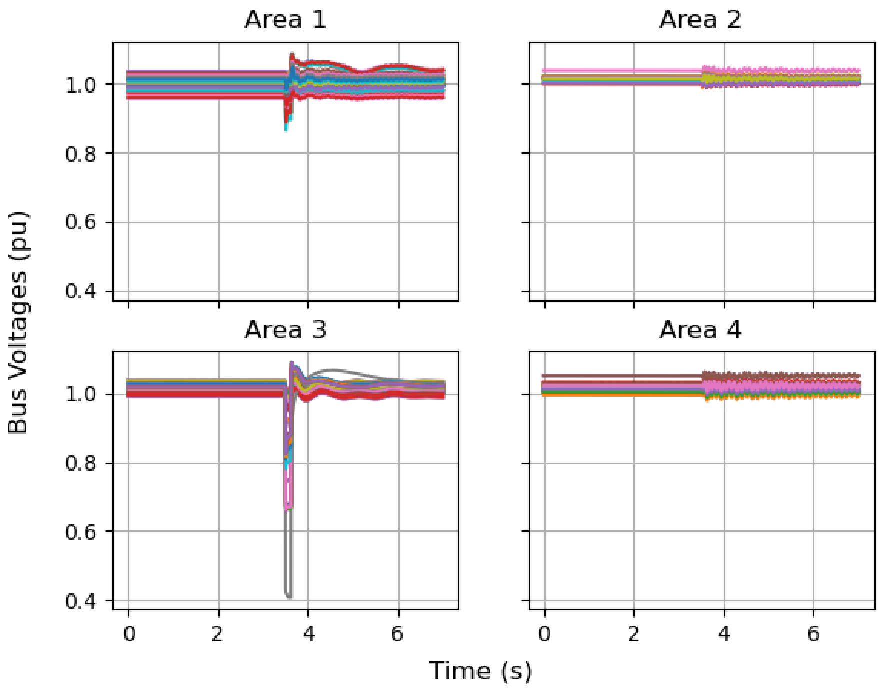

Figure 84 Voltages in different areas for low demand synthetic NEM network case with no GFMs for fault in area 3

The rest of the section describes the key observations from these cases:

- The impact of GFM on the fault voltage depends on the fault – for faults in areas 1 and 4, increased percentage of GFM leads to slightly higher fault voltages, as well as lower post-fault clearance overvoltages at the fault location, for example, in Figure 85. For faults in areas 2 and 3 the changes in GFM lead to minimal to no changes in the voltages during the fault.

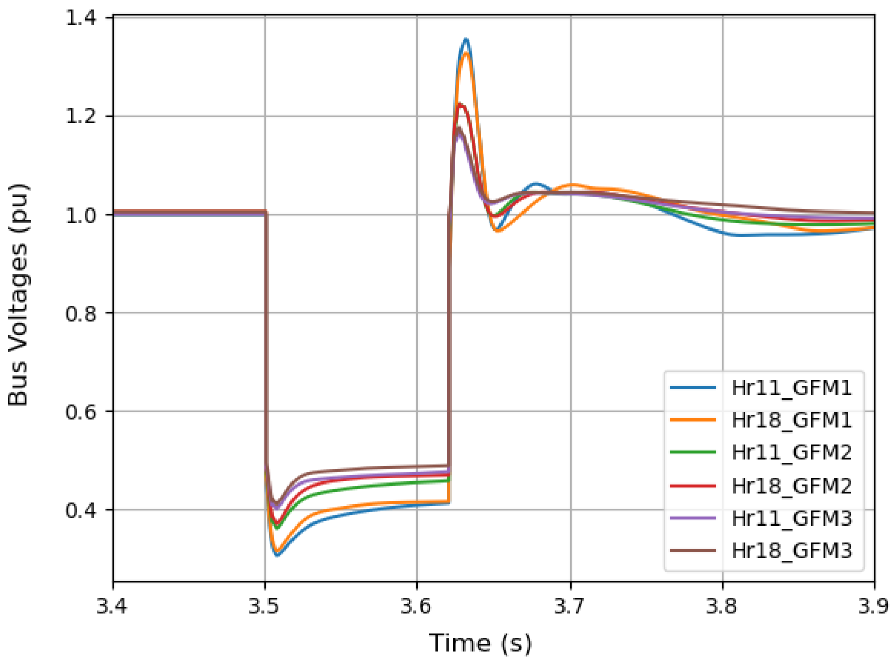

Figure 85 Fault voltages for fault in area 1 for the different synthetic NEM cases

- Similar to the reduced circuit, while some voltage dips are experienced in other areas, this behaviour also depends on the fault – for some of the faults the other (especially distant) areas experience minimal voltage changes, for example, fault in area 2 causes voltage dips in areas 1 and 4 apart from itself, while the area 3 voltages do not dip as much – see Figure 86.

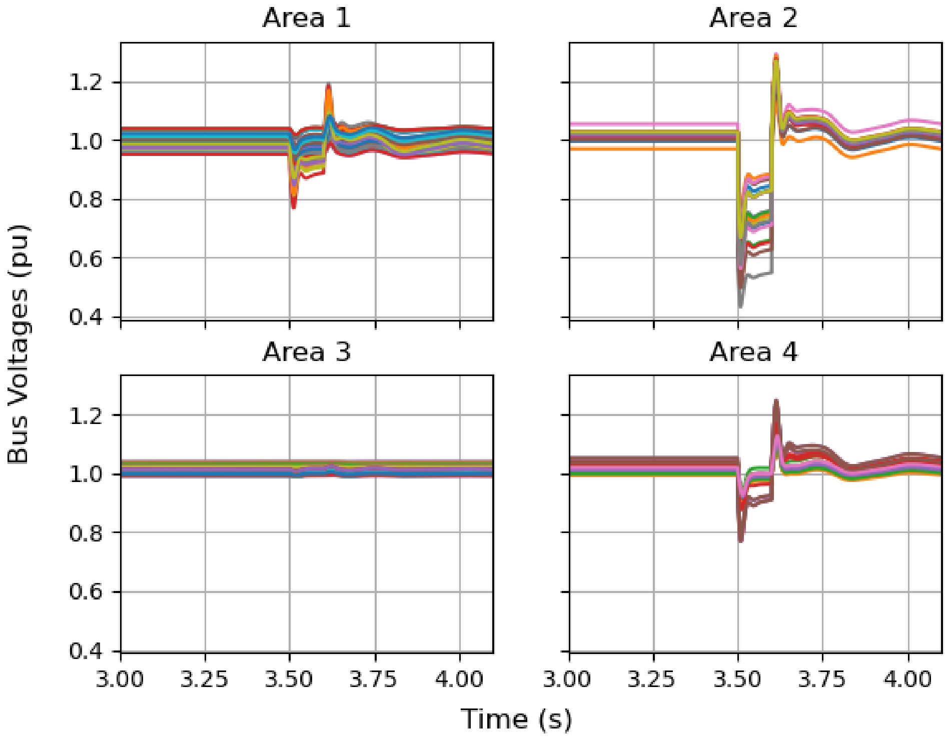

Figure 86 Voltages in different areas for low demand synthetic NEM network GFM1 case for fault in area 2

- However, especially for certain faults, as observed in Figure 86, large overvoltages after clearing the fault are also observed in other areas in addition to the faulted area.
- Similarly to the reduced circuit, most additional reactive power during the fault again comes from the area with the fault, as shown in Figure 87. Generators in other areas do provide some additional reactive power during the fault, but the area with the fault has the largest contribution. Between the low/high demand cases, and between different percentages of GFM, the differences in the additional reactive power provided by the generators in each area is small, similar to the reduced circuit. Note, the image shows a change in the reactive power injected by the generators compared to the pre-fault condition, so a generator could be injecting or absorbing reactive power before the fault occurred and both would be represented as zero in the pre-fault condition for this figure.

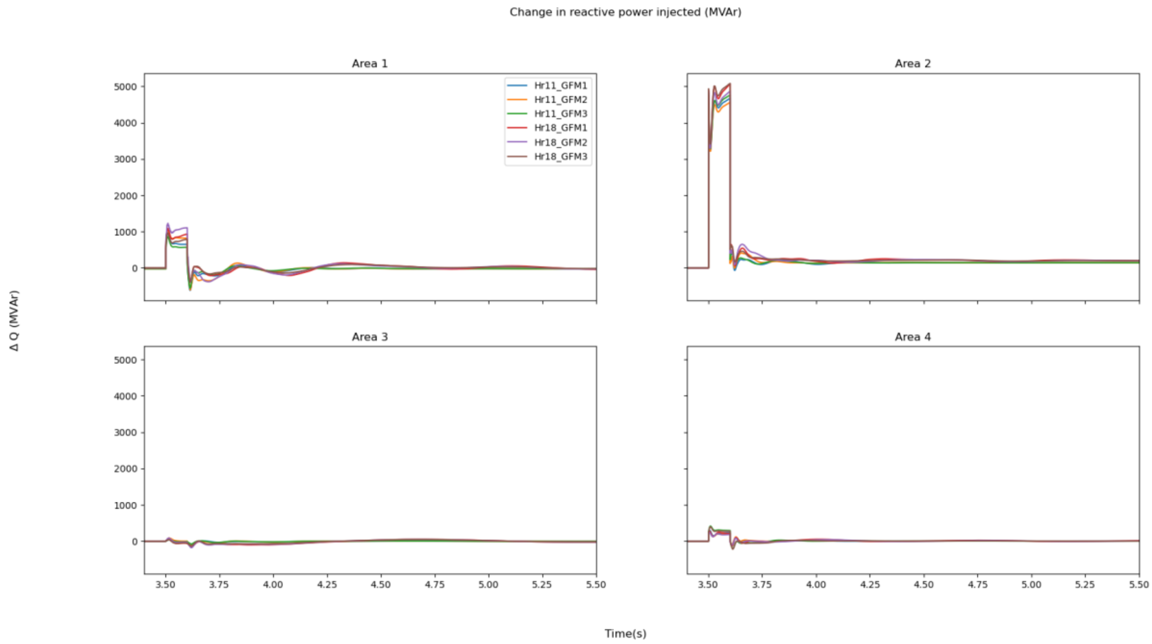

Figure 87 Change in/additional reactive power injection by generators in different areas in response to a fault in area 2 for different cases

- In terms of the generator (synchronous and IBR) active power changes during the fault, the largest change is again observed in the generators in the area with the fault. Figure 88 shows the change in the active power injected by generators in each area. Note again, that this is the change relative to the pre-fault injected active power, so a negative value in this graph does not mean that the generators absorbed active power – just that the injected active power into the network by generators in that area increased or decreased per the amount shown in the graph. For the change in active power, the low and high demand cases have significant differences, and there are smaller differences due to different levels of GFM percentages as well.

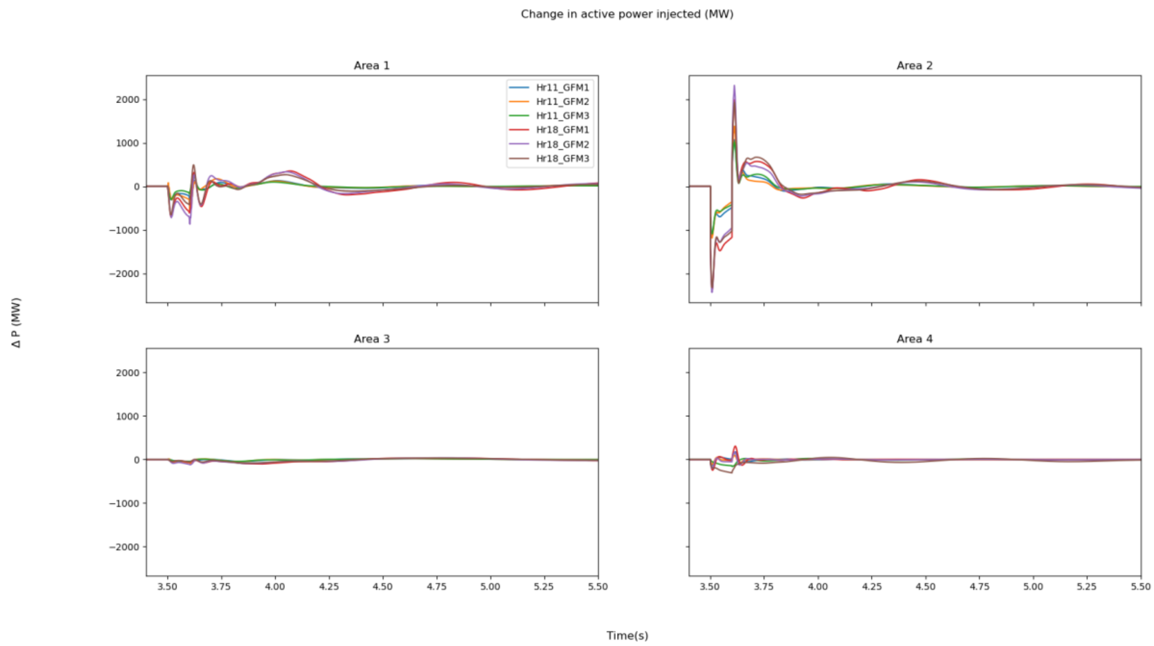

Figure 88 Change in/additional active power injection by generators in different areas in response to a fault in area 2 for different cases

- For the faults applied, the generator phase angle changes are observed to not be as sudden compared to the reduced network – for example Figure 89 shows the changes in the generator angles in the four areas for a fault in area 1. The largest changes in the generator angles are observed for generators in the area with the fault, as for the reduced network, however the extent seems to depend on the fault. For example, in Figure 89 with the fault in area 1, area 1 generators have the largest changes in phase angles, very closely followed by generators in area 2, and generators in area 3 also experience some changes in phase angles. However, as shown in Figure 90, for a fault in area 2, generators in other areas experience much smaller phase angle changes compared to generators in area 2. Finally, Figure 91 explores the impact of low/high demand and of different percentages of GFM on these changes for generators in area 2 for the fault in area 2. Similar to the observation for the reduced network, the changes in phase angles are smaller with GFMs (in this case, more GFMs) for both low and high demand cases.

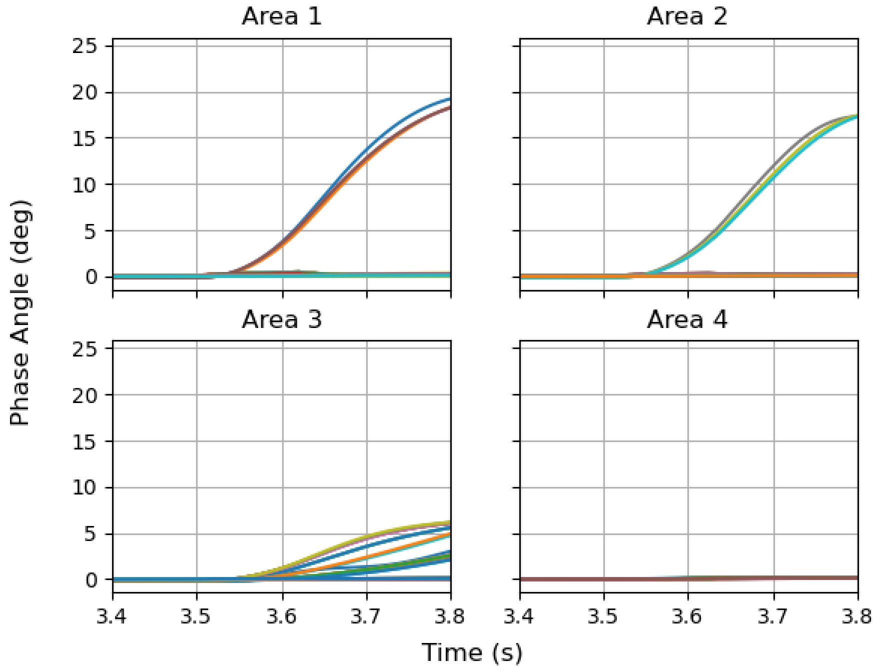

Figure 89 Generator phase angle changes for a fault in area 1 for the high demand GFM1 synthetic NEM network case

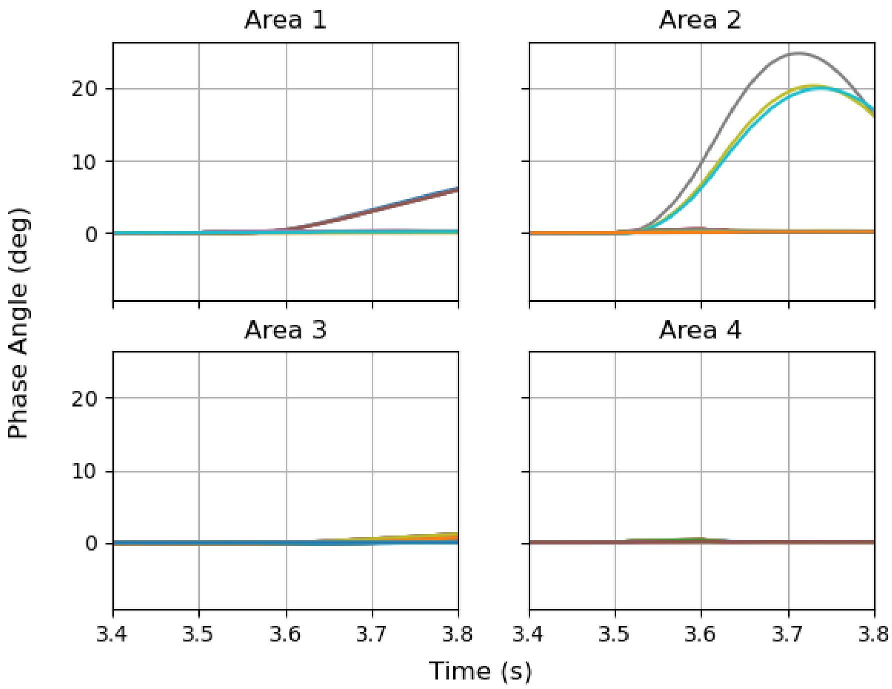

Figure 90 Generator phase angle changes for a fault in area 2 for the high demand GFM1 synthetic NEM network case

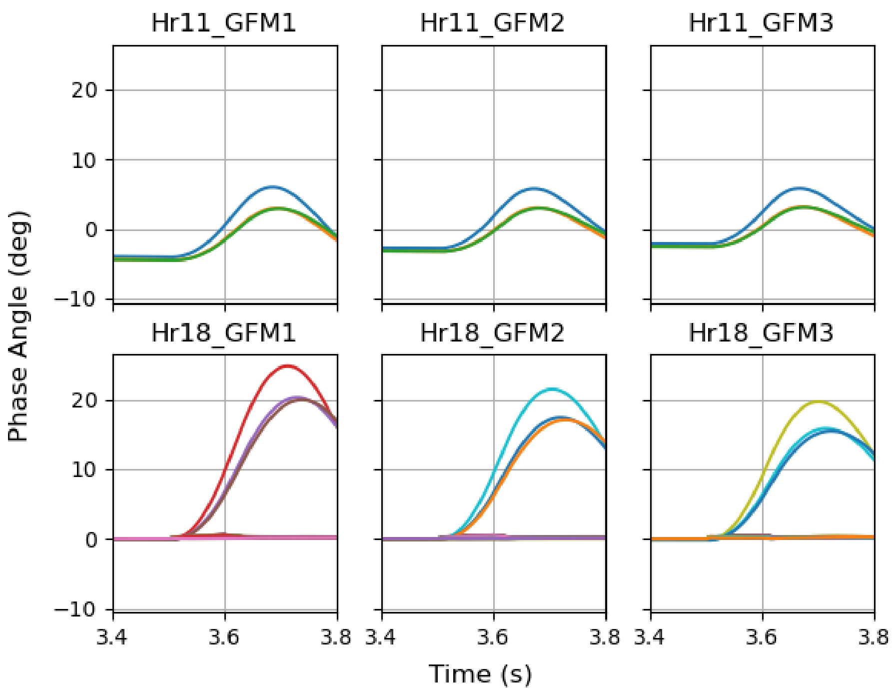

Figure 91 Generator phase angle changes for generators in area 2 for a fault in area 2 across the different cases

4.4.3 Discussion: PDT and EMT simulations, and next steps

In this chapter, PDT simulation setups and key observations for each of the case studies were discussed. The following are some insights based on the results from all these cases:

- Between EMT and PDT simulations, there are some fundamental representation differences (the following list is non-exhaustive):
  - Network model (positive sequence model in PDT versus unbalanced modelling in EMT; and algebraic equation representation in PDT versus differential-algebraic equations represented in EMT)
  - Dynamics and timeframes (faster timeframes are not captured in PDT simulations)
  - Applied contingency – line-to-line-to-ground faults were applied in EMT whereas in PDT a high impedance balanced fault were applied
  - While some effort was taken to align the behaviour of the individual generator models, there do remain differences in terms of model structure and behaviour
- Some key trends from the PDT simulations include:
  - Between the different cases, the fault current levels were similar. This observation is consistent with the observations for the EMT cases, where the fault currents for the same fault remained similar between the different cases for the same fault.
  - Again true for both the small and the larger network, the voltage dip during the fault was largest on the buses in the same area as the fault, and some buses in other

areas also experienced a shallower voltage dip. The extent of the voltage dip experienced in other areas depended on the fault. Unlike the EMT cases, there was no voltage rise during the fault for remote buses, indicating that this aspect may be related to balanced fault applied in PDT as opposed to unbalanced faults – and such voltage rise may also be related to the ability to represent the negative and zero sequence networks during the simulation as well as the coupling between them.

- After the fault was cleared, there a voltage rise temporarily occurred for both the smaller and the larger PDT network, that was most severe in the area with the fault, but in some cases a voltages in other areas also rose, and again in some cases these voltages went above 1.1 pu. Note, no protection devices were modelled in the PDT simulations. Similar to the previous point, in PDT simulations the voltage rise in remote buses (buses from other areas) tended to be shallower, unlike some overvoltages in remote buses in EMT cases.
- For both the small and large network, most of the reactive power support to the fault came from the generators (IBRs as well as synchronous) from the same area. Generators in other areas did contribute, but the magnitude of the added reactive power injections was much higher for the generators in the area with the fault.
- In both EMT and PDT simulations for the small network, there was a similar level of phase angle change observed, in the range of 10-40 degrees within the first 0.05 seconds, especially for buses in the same area as the fault. The other area buses did experience some phase changes, but this extent depended on the exact fault. With larger share of IBRs, this phase angle change tended to be larger. For larger network PDT simulations, the phase angle changes were not as severe and tended to rise slowly. These phase angle changes reduced slightly with more GFMs, as observed in both the small and large PDT network case studies.

As further points of discussion and next steps, the following points may be considered:

- A major difference between the PDT and EMT simulations was in terms of the stable/unstable characteristics. For the smaller network, all cases before 2034 were stable in the EMT studies, whereas certain high demand cases were found to be unstable even for the cases corresponding to the earlier years in PDT. Further, the 100% IBR cases showed unstable behaviours for the fault cases for the small network regardless of the demand level. Within these differences, the PDT cases were more conservative (i.e. in such cases, PDT showed unstable behaviours but EMT did not). Further investigation into the extent to which such differences would be needed to uncover the next steps needed to align PDT and EMT simulations better.
- Some steps in this direction could be more extensive testing and benchmarking of the models – though this step is also applicable to understand PDT simulations with new devices such as IBRs with different technologies better. For example, in single machine infinite bus step tests, BESS units in GFL and GFM modes showed similar

response, but there were clear differences in system-wide studies with BESS units operating in GFL and GFM modes with the same parameterization.

– Future efforts could also look at other aspects of better aligning models and network between EMT and PDT studies, including network models, generator models and load models. One example of different behaviour for PDT and EMT models observed during this stage of the project was the difference due to DC-side modelling. In future work efforts, the impact of modelling DC-side dynamics and controls on the network response in both EMT and PDT domains can be explored. Some representations do exist currently in EMT models, however, for most PDT models of IBRs the DC-side modelling is currently ignored.
– Certain behaviours observed in the studies, for example voltage dip/recovery can vary significantly with different load models, especially if detailed load representation including motor modelling/stalling and DER representation is included. The present study did not have such load models, but this could be an aspect important to include in the future, especially given the large numbers of installations of DER in the Australian network.

5 Insights

What services (technical characteristics to be provided to the power system) are most important from the scenarios considered in this work?

Readers are reminded that due to the extensive number of technical characteristics determined through the Milestone 1 roadmap review, not all could be studied in this stage, and a focus was given to fast characteristics as originally identified in Section 4.1.

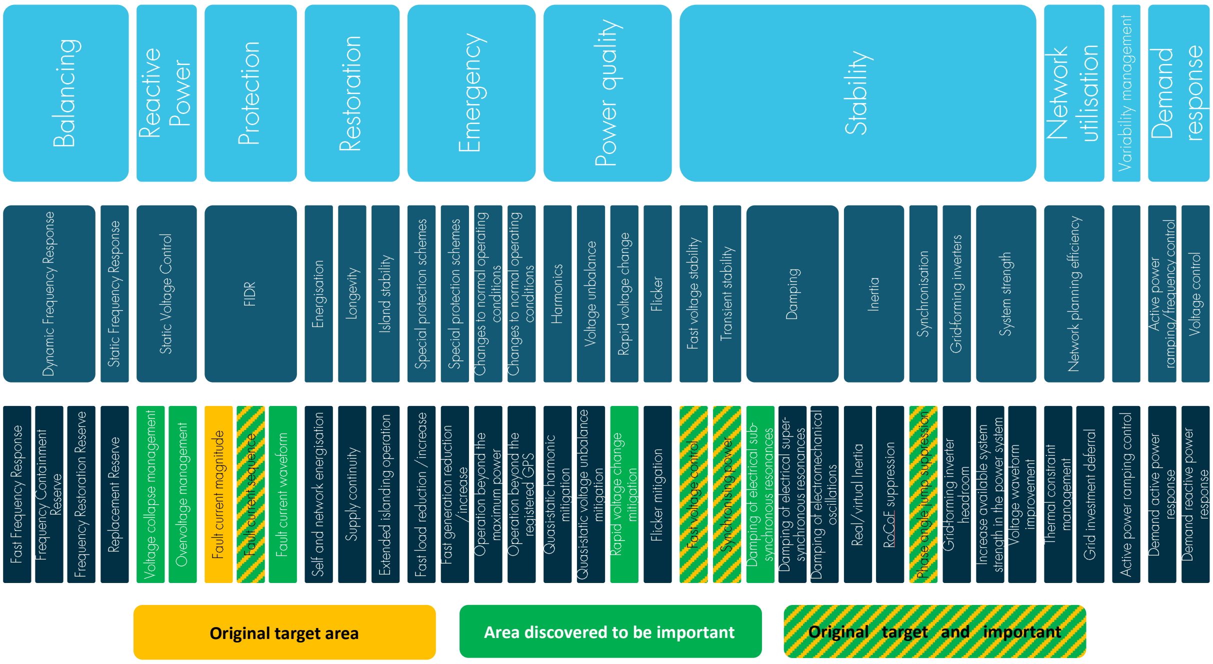

Figure 92 Important services for an evolving mainland NEM

- **Phase angle jump suppression**: A concern as the system shifts to be more IBR dominant. Larger and more wide-spread shifts seen across the system as interconnection impedances decrease and fewer synchronous machines online.
- **Rapid voltage change mitigation:** As synchronous machine dominance decreased and generation was replaced with IBR fleet, the propensity for remote overvoltages during the fault increased.
- **Fast voltage control:** Extended voltage dip times were observed if a minimum amount of GFM IBRs were not available in the system. This appeared to be readily mitigated by increasing the share of GFM IBRs in the system.
- **Fault current waveform & Fault current Sequence:** There was a notable decrease in the quality/distinctness of the positive and negative sequence fault current components in cases with a high IBR penetration, despite overall magnitudes of components not being

significantly altered between scenarios[12]. Whether this will have an impact on the ability of impedance-based protection relays to operate correctly is an area for further research.

- **Synchronising power:** Through studies varying the proportion of GFM IBR technology available in a scenario, it was clearly demonstrated that there is a minimum amount of grid-forming capability (be it from GFM IBRs or synchronous machines) required to allow GFL IBR to remain correctly synchronised to the grid. This was determined to be an absolute minimum of 30% GFM IBR (by MVA rating) for a 100% IBR scenario.
- **Overvoltage management:** The extensive use of 500 kV networks for upcoming network projects introduces distinct voltage management problems during periods of light system loading. In this work it was assumed that each line would be adequately compensated with shunt reactors, however this may be an opportunity for existing plant to provide voltage management services.
- **Voltage collapse management:** The shift in major generation centre locations while major load centres remain unchanged poses a challenge for voltage management during heavy loads. The scenarios studied needed to consider the presence of new bulk static reactive support devices to prevent post-contingency voltage collapse for high-demand scenarios.

How should these services be delivered?

As discussed in the introduction of this work, the intent of this Stage 4 was to identify new technical requirements an evolving NEM may have to ensure that none are missed, and system security is maintained. Determining whether such qualities should be delivered by market mechanisms, and which should be embedded in technical requirements was not part of the scope of this stage. This is to be considered with an economic perspective to the problem.

However, a key factor that must be at the core of the decision to deliver a characteristic as a service is the ability for the provision of that characteristic to be <u>measured</u>, and clearly <u>attributable</u> to a given device. Where this cannot be readily achieved, it is best to provide this characteristic through mandate of technical requirements.

What was different to originally expected?

- There was not the material degradation in fault current expected as synchronous machines closed across the system. From the scenarios considered, fault current magnitudes kept relatively constant, only dropping for the 100% IBR-only 2034 scenario. This is due to the fact that there is a need for a greater MVA amount of IBR devices to be online operating at a lower MW output due to the variable nature of their input energy source, hence reduced IBR fault current on an individual basis is offset by the fact there

[12] Note the discussion in Peak fault current changes, whereby it is explained that the variable output nature of the IBR devices necessitates that more units will be online (albeit at lower active power outputs), and the increased MVA of inverters online compensates for the lower fault current that each unit can provide.

will need to be far more IBR online to deliver the same MW that synchronous machines provide.

- Although unlikely given the number of synchronous-based machines likely to remain online well into the future, the NEM can be run using 100% IBR devices without any synchronous machines online whatsoever, so long as the IBR fleet consists of a minimum of 30% GFM technology.
- Frequency retains its meaning in a 100% IBR system, and energy imbalances do not manifest as local voltage depressions.
- For the IBR models used, the ratios between negative and positive phase sequence kept relatively constant throughout the years, with major changes in ratio more related to the MVA of machines online rather than their generation technology type.
- While the PDT model showed very similar results to the EMT model in terms of total fault current contribution levels, residual voltages during faults and approximate phase-angle changes, there were notable differences in some phenomena observed (e.g., in-fault remote overvoltages not present in PDT) and an increased sensitivity of the PDT model to system loading, with lightly-loaded PDT cases returning optimistically stable results, but heavily loaded cases returning more pessimistic unstable results when compared to EMT simulations.

What needs further investigation?

- Although the raw magnitude numbers do not seem too different from the current system, it is not clear if the change in *quality* of the fault current provision from an IBR-dominant will present a material problem to network protection relays in correctly discriminating fault conditions. Studies with real protection relay algorithms are recommended.
- It is not entirely clear whether the lack of change in the negative to positive sequence fault current is a result of the capability of the generic models used in this work, or if it is genuinely not a material concern. To properly evaluate, a suite of OEM models needs to be benchmarked against one another.
- The dynamic behaviour of loads was not considered in this work, however given the sensitivities seen and expanded voltage dips of cases with high amounts of IBR, the load performance may be pivotal to the overall NEM performance in the future.

6 Future Work Recommendations

Based on this 2024 research roadmap review, the following aspects have a residual importance of "high" for the 2024 work and beyond:

Technical Need	Technology Gap Necessitating Research
Fault current sequence	Current limited nature of all IBRs
Fault current waveform	While this topic warrants significant research, based on experience to date it is unlikely that a GFM fault current waveform will only contain fundamental frequency
Fast load reduction / increase	The capabilities and limitations of demand response are not well known
Operation beyond the maximum power	Technology capability and limitation, including impact on the lifetime, is not well understood at this point
Operation beyond the registered Generator Performance Standards (GPS)	Technology capability and limitation, including impact on the lifetime, is not well understood at this point
Quasi-static harmonic mitigation	Bandwidth limitation of all IBRs
Damping of electrical sub-synchronous resonances	Lack of sufficient understanding if GFM can adversely interact between themselves or with GFL.
Damping of electrical super-synchronous resonances	GFM can suppress super-synchronous up to its bandwidth.
Grid-forming inverter headroom	GFM stability can be degraded if operated current limited. Reserving some headroom below the current rating at all times will ensure that the GFM will not hit the limit during or after the disturbance and can therefore provide its best performance.
Voltage waveform improvement	GFMs are shown to improve the damping of sub-synchronous oscillations. However, the impact will be on frequency components up to its bandwidth and won't be effective on harmonics above ~5-7 order.
Active power ramping control	Wind and solar with better ramping control capability

In addition to the above, further research is recommended to investigate:

- Expansion and further refinement of the wide-area EMT model to consider additional scenarios and ensure its fitness-for-purpose for evaluation of a wider set of system needs / potential system services.
- Expanding technical needs and potential services evaluation studies to additional areas identified in the Topic 6 roadmap review, with priority for:
  - Evaluating the effect of an IBR-dominated system on the operation of protection relay models that rely on specific fault current characteristics (magnitude, waveshape, sequences) to discern fault presence.
  - Evaluating the effect of an IBR-dominated system on stability of aggregated distribution connected Distributed Energy Resources (DER) and Consumer Energy Resources (CER) (e.g., rooftop PV, heat-pumps, EV chargers, residential BESS) from perspectives of:
    - Control system stability

        - Protection activation
    - Evaluation of services DER could provide to an IBR-dominant NEM at bulk supply points.
- Research and consider how any additional identified power system technical needs following this work should be incentivized and maintained, either through technical standards or ancillary market mechanisms.
- How the definition of known offline study stability evaluation metrics and criteria such as damping will evolve as the generation mix changes and what resultant impact it might have on the calculation methodologies used, for example the extent to which Fourier transform can be reliably used?
- Inclusion of impedance-based network protection relays within the case to evaluate whether the reductions in quality of fault current provision due to higher IBR penetration will lead to potential maloperation of network protection relays.
- Evaluation on how manufacturer-specific models compare to generic models used in this work, and any changes to generic models that may be required to better represent current provision limitations.
- Explore the impact of modelling DC-side dynamics and controls on the unique responses seen in a 100% IBR case in both EMT and PDT domains.
- Inclusion of an improved load model to determine the impact of dynamic distribution load and DER on the performance of the system.
    - Inclusion of CER aspects (home BESS and EV charging).
- Investigation of N-1-1 contingencies impact on fault current provision.
    - Intra-regional circuit losses.
    - Synchronous-connected circuit losses.
- Investigation (trends) of how resonant points of the system will change as the system reduces in the number of synchronous machines. Is resonance mitigation a service being lost?

7 Shortened forms

Acronym	Meaning
ACSR	Aluminium Clad, Steel Reinforced
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AR-PST	Australian Power System Renewables Transition
BESS	Battery Energy Storage System
C	Capacitor
CB	Circuit Breaker
CER	Consumer energy resources
CSIRO	Commonwealth Science and Industrial Research Organisation
DC	Direct Current
DER	Distributed Energy Resources
EMT	Electromagnetic Transient
EPRI	Electric Power Research Institute
FFT	Fast Fourier Transform
FRT	Fault Ride-through
GFL	Grid following
GFM	Grid forming
GT	Gas Turbine
HVRT	High-voltage ride-through
IBR	Inverter based loads
kA	kiloamp
kV	kilovolt
kW	kiloWatt
L	Inductor
LV	Low Voltage
LVRT	Low-voltage ride-through
MMIB	Multiple Machine, Infinite Bus
MPPT	Maximum Power-Point Tracking
MV	Medium Voltage
MVA	Mega volt-amp
MVAr	Mega volt-amp reactive
MW	Megawatt
NEM	National Electricity Market
OCGT	Open-cycle Gas Turbine
OEM	Original Equipment Manufacturer
P	Active Power
PDT	Phasor Domain Transient
PLL	Phase-locked loop
PoC	Point of Connection
PPC	Plant Park Control / Park Power Controller

Acronym	Meaning
PSCAD	Power Systems Computer Aided Design
PSS®E	Power Systems Simulator for Engineering
pu	Per-unit
PV	Photovoltaic
Q	Reactive Power
REZ	Renewable Energy Zone
RMS	Root Mean Square
RoCoF	Rate of Change of Frequency
SCR	Short Circuit Ratio
SMIB	Single Machine, Infinite Bus
SRAS	System Restart Ancillary Services
SRS	System Restart Standard
TRX	Transformer
VSM	Virtual Synchronous Machine
WECC	Western Electricity Coordination Council

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Appendix A Roadmap review

The following table describes the technology gaps contemplated as part of the roadmap review.

Technology gap type	Description	Comments
Scalability	The ability to deploy the technology broadly or at the required capacity across the system	Useful when the technology works in theory or at small scale but hasn't been demonstrated under high penetration or wide deployment
Cost-effectiveness	Whether the technology can deliver the service at a competitive cost, considering capex, OPEX, and opportunity costs	Particularly relevant when trade-offs exist between services (e.g. BESS headroom for GFM vs energy arbitrage)
Lack of field demonstration	The technology is technically capable, but lacks widespread, validated deployment for the specific service under real system conditions	Especially applies to HVDC, demand-side response, and some emerging GFM or DER capabilities
Performance uncertainty	The technical performance is not fully characterised or may vary depending on system strength, configuration, or control tuning	Useful when simulations or tests show promise but there is variability in response (e.g. GFM fault current shape)
Integration complexity	Challenges in integrating the technology into existing system operations, protection schemes, or market frameworks	Usually relevant to distributed or demand-side assets that require aggregation, communications, or market mechanisms to be effective

The table below includes the following columns:

1. Service – The specific grid-related or technical service under consideration. This could refer to system support functions like frequency response, voltage control, or inertia.
2. Category – A broad classification of the service, which may indicate whether it pertains to system stability, reliability, security, or market operations.
3. Sub-category – A more detailed breakdown of the service, specifying its technical nature or role within the broader category.
4. Timeframe (Response Time) – The required speed at which the service must respond to be effective in relation to each particular phenomenon. This could range from milliseconds to seconds, minutes, or longer (e.g., reserve services, energy shifting). This helps shortlisting phenomena with faster dynamics in the range of milliseconds to several seconds for the purpose of power system dynamic modelling discussed in this report.
5. Currently provided by – The existing technologies capable of providing this service. This could include traditional synchronous generators, BESS, demand response, or other technologies.
6. Technology gap – Any deficiencies or limitations in current technologies that hinder their ability to provide this service effectively. This may include gaps in performance, cost, scalability, or availability.
7. Other gaps (e.g. network, regulatory) – Additional challenges beyond technology that could impact the service's effectiveness. These may include network constraints, lack of regulatory frameworks, market design issues, or policy barriers.

8. Criticality in Australia – An assessment of how crucial this service is within the Australian NEM, and its known and anticipated challenges.
9. Assessment methodology – The type of dynamic modelling tools, and the extent of the power system needs to be modelled for accurate assessment of each phenomenon.
10. Included in 2021 research – Indicates whether this service was already considered in the 2021 research roadmap. As indicated in the table, many new categories were identified in the 2024 research.
11. Importance for the 2024 research – The relevance and priority of this service in the 2024 research efforts. It reflects whether new developments, challenges, or technology improvements warrant further investigation.
12. Residual importance after the 2024 research – This refers to the extent to which further research will be required beyond the 2024 project. A low residual need indicates that the 2024 research is expected to largely address the knowledge gaps, even though the service itself may continue to be relevant and required in practice.

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
	Capacity						Medium	N/A	No	No	No
	Resilience						Medium	N/A	No	No	No
Balancing	**Fast frequency response**	Dynamic frequency response	< 1 s	GFL BESS GFM BESS PHES (partially)	Wind (performance uncertainty), Solar (performance uncertainty), Demand (lack of field demonstration, integration complexity), FACTS (performance uncertainty), HVDC (lack of field demonstration)	The current limited nature of all IBRs means that this service may not be delivered simultaneous to others especially when there is a combined voltage and frequency disturbance	High	MMIB PDT MMIB EMT	Yes	High	Medium
Balancing	**Frequency containment reserve**	Dynamic frequency response	<1 s up to tens of seconds	GFL BESS GFM BESS SG including PHES	Wind (performance uncertainty), Solar (performance uncertainty), Demand (lack of field demonstration), FACTS (performance uncertainty), HVDC (lack of field demonstration)	The same as above	High	MMIB PDT MMIB EMT Multi-mass PDT (partially)	Yes	Medium	Low
Balancing	**Frequency restoration reserve**	Dynamic frequency response	Tens of seconds up to five minutes	GFL BESS GFM BESS SG including PHES Wind and solar (partially)	None	None	Medium	MMIB PDT MMIB PDT Multi-mass PDT (partially)	Yes	Low	Low
Balancing	**Replacement reserve**	Static frequency response	Tens of minutes to hours	Synchronous generators and IBRs (subject to resource availability)	None	None	Medium	Outside the scope of power system dynamic and load flow studies	Yes	No	Low

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
Demand response	**Demand active power response**	Active power ramping/frequency control	All timeframes	Distributed IBRs CERs Loads (limited)	Inferior capability and control of distributed IBRs relative to large-scale IBRs Lack of technical capability and performance standards for large loads	Large change in active power in metropolitan areas with several GW of distributed IBRs can cause an unintended voltage disturbance.	High	PDT MMIB	Yes	No	Medium
Demand response	**Demand reactive power response**	Voltage control	All timeframes	Distributed IBRs CERs	The same as above	Voltage control mode in distribution systems is not widely used.	Medium	PDMT MMIB	No	No	Medium
Distribution networks	**DNSP level services**						Medium	PDT MMIB	No	No	Low
Emergency	**Operation beyond the maximum power**	Changes to normal operating conditions	Varied and potentially for all time scales	Potentially all technologies	Technology capability and limitation, including impact on the lifetime, is not well understood at this point		High	SMIB PDT SMIB EMT, and MMIB studies may be required depending on particular services intended	No	Low	High
Emergency	**Operation beyond the registered GPS**	Changes to normal operating conditions	Varied and potentially for all time scales	Potentially all technologies	The same as above		High	The same above	No	Low	High
Emergency response	**Fast load reduction /increase**	Special protection schemes	<10 s	BESS PHES (partially) UFLS SIPS Demand response HVDC	The capabilities and limitations of demand response is not well known	Determining how much a change and how fast will be permitted by power system and the potential impact on other forms of system stability	High	MMIB PDT MMIB EMT	No	Low	High
Emergency response	**Fast generation reduction /increase**	Special protection schemes	<10 s	BESS PHES (partially) OFGS SIPS Demand response	The same as above	The same as above	High	MMIB PDT MMIB EMT	No	Medium	Medium

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
				HVDC							
Network utilisation	**Thermal constraint management**	Network operation efficiency	Several minutes/hours	BESS PHES GET, e.g. DLR SIPS	Longer duration storage (cost-effectiveness)	Impact on other revenue streams	High	Load flow	No	No	Medium
Network utilisation	**Grid investment deferral**	Network planning efficiency		BESS PHES (sometimes as by itself it may rely on new transmission networks) GET, e.g. DLR	Longer duration storage (cost-effectiveness)	The potential need to upgrade network protection systems is not	High	Load flow	No	No	Medium
Oscillations	**Damping of electromechanical oscillations**	Damping	Continuous	SG with PSS SC with PSS (less widely used) FACTS with POD GFL/GFM with POD like functions	GFL/GFM with POD like functions have been occasionally implemented in practical applications, however, it is not a common occurrence. Considerations should also be applied on the frequency range for which the damping is required. This is because the broader the frequency range, the more difficult it is to design an effective control system. Currently installed and considered synchronous condensers in the NEM do not have a PSS-like	This problem remains even in a 100% IBR scenario as there will most likely be many online synchronous condensers	High	MMIB PDT Small-signal stability analysis tools	Yes	Low	Medium

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
					function designed.						
Power quality	**Quasi-static harmonic mitigation**	Harmonics	Continuous	Passive and active filters Some IBRs both GFL and GFM SG/SC (limited inherent capability)	Bandwidth limitation of all IBRs Continuous allocation of some of the total current Potential impact on other services	Filters do not provide any other benefits and create anti-resonances. The potential for filter to exacerbate over-voltages	High	Harmonic power flow MMIB EMT to analyse resonances	No	No	High
Power quality	**Quasi-static voltage unbalance mitigation**	Voltage unbalance	Continuous	Some IBRs both GFL and GFM SG/SC (limited inherent capability)	Within the bandwidth of the control system, so it is easier to address with IBR than harmonics		Medium	Harmonic power flow MMIB EMT to analyse resonances	No	No	Medium
Power quality	**Rapid voltage change mitigation**	Rapid voltage change	<10 s	SG/SC GFM (potentially but not assessed in this regard)	None currently identified with regard to the limitations of the source providing the service.	Further work is required to determine if this should be sought as a service rather than mandatory requirements on all plant not to create rapid voltage changes greater than certain magnitude	Medium	MMIB EMT	No	No (partially in Topic 5)	Medium
Power quality	**Flicker mitigation**	Flicker	Continuous	Flicker levels are managed by controlling the emitting source rather than using other devices in the power system.	None	The same as above. Furthermore, any potential adverse impact on other services due to IBR modifications to provide this service is not currently known. Here flicker requirements	Medium	Flicker calculation tools	No	No	Medium

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
						are not considered as a success criterion for the permissible level of low frequency oscillations.					
Protection	**Fault current magnitude**	FDIR	A few cycles	SG SC GFL and GFM (partially, less widely assessed)	Current limited nature of all IBRs Despite providing an at least 100% current during the fault, it may not be always prudent to count IBR's fault current as it might degrade other aspects of fault current such as sequence and waveform	Potential adverse impact on other services Potential adverse impact on the GFM dynamic performance	High	MMIB PDT and EMT including generation, network and protection dynamic models	No	High	Medium
Protection	**Fault current sequence**	FDIR	A few cycles	SG SC GFL and GFM IBR (varies among different designs)	Current limited nature of all IBRs	Potential adverse impact on other services	Medium	SMIB EMT (first stage) MMIB EMT including generation, network and protection dynamic models	No	Low	High
Protection	**Fault current waveform**	FDIR	A few cycles	SG SC GFM (not widely understood)	While this topic warrants significant research, based on experience to date it is unlikely that a GFM fault current waveform will only contain fundamental frequency	Potential adverse impact on GFM stability if the bandwidth becomes limited to reduce the injection of non-fundamental frequency components	Medium	SMIB EMT (first stage) MMIB EMT including generation, network and protection dynamic models	No	Low	High
Reactive power	**Voltage collapse management**	Static voltage control	Several seconds/minutes	All technologies	Simultaneous provision of high P and Q	Long distances in large onshore	Medium	PV/QV analysis	Yes	Medium	Low

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
					especially if other services are also sought	and offshore wind farms Distances between areas of concentration of IBRs and load centres		MMIB PDT if control systems are involved.			
Reactive power	**Over-voltage management**	Static voltage control	Several seconds/minutes	IBRs and synchronous generators	Many existing IBRs have limited reactive power capability at low/no dispatch	The same as above and The impact of transformer saturation and surge arrester withstand capability Added overvoltages due to the harmonic content	High	PDT and EMT SMIB (first stage) PDT and EMT (detailed)	No	Medium	Medium
Restoration	**Self and network energisation**	Energisation	Tens of seconds/minutes	SG GFM GFL (support only)	To be investigated in Topic 5	To be investigated in Topic 5	High	MMIB EMT including generation, network and protection dynamic models	No	No	N/A (Topic 5)
Restoration	**Supply continuity**	Longevity	Tens of minutes/hours	SG GFM (limited)	To be investigated in Topic 5	To be investigated in Topic 5	High	Outside the scope of power system dynamic and load flow studies	Yes	No	N/A (Topic 5)
Restoration	**Extended islanding operation**	Island stability	Milliseconds to tens of second	SG GFM	To be investigated in Topic 5	To be investigated in Topic 5	High	MMIB EMT studies	No	No	N/A (Topic 5)
Stability	**Fast voltage control**	Fast voltage stability	<1 s	Most IBRs, GFL and GFM	None		High	SMIB PDT and EMT (first stage) MMIB PDT and EMT (detailed)	No	High	Medium
Stability	**Synchronising power**	Transient stability	A few cycles	SG SC GFM	Synchronizing power is a clearly defined/quantified term for SG and SC, but not for the GFM. For GFM current limitations and	Proximity to other devices: For SG/SC: the higher the number of synchronous machines, the higher the	High	MMIB PDT and EMT	No	High	Medium

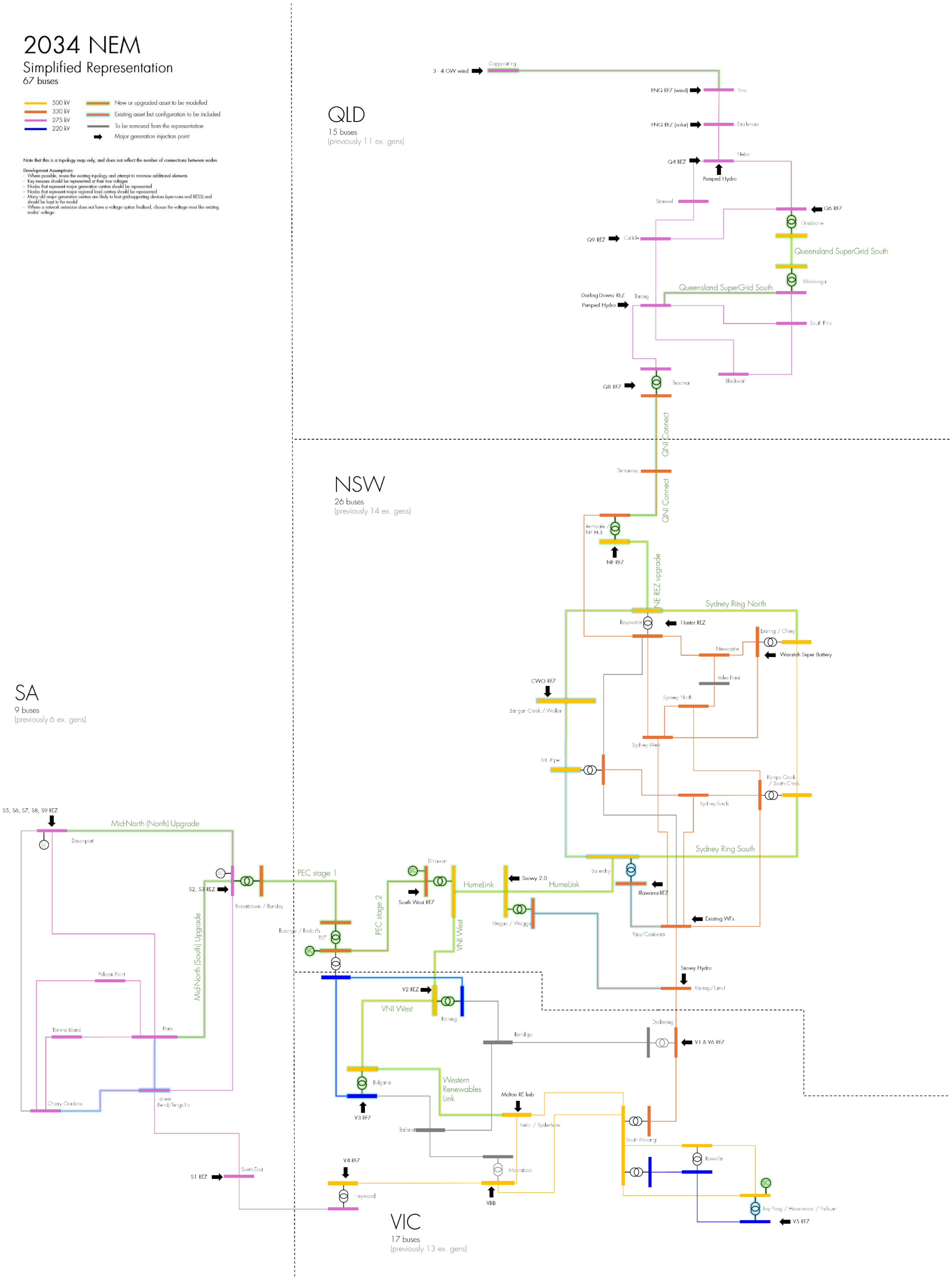
Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
					proximity to other GFM/SG/SC should be studied as potential limitations. Further insights may also be provided in Topic 1.	synchronizing power The inverse is true for GFM					
Stability	**Damping of electrical sub-synchronous resonances**	Damping	A few cycles up to several seconds	SG SC GFM	Lack of sufficient understanding if GFM can adversely interact between themselves or with GFL. Further insights may also be provided in Topic 1.	The success criteria in terms of maximum permissible magnitude and duration of oscillations as function of the dominant frequency of oscillations and the cause is not currently defined.	High	MMIB EMT	No	High	High
Stability	**Real/virtual Inertia**	Inertia	<3 s	SG SC GFM	Potential conflict between the inertia and FFR for a GFM Further insights may also be provided in Topic 1.	Current limited nature of all IBRs means that this service may not be delivered simultaneous to others especially when there is a combined voltage and frequency disturbance Coupling between active and reactive power under low system strength conditions which may result a voltage collapse when providing	High	MMIB PDT MMIB EMT Multi-mass PDT (partially)	Yes	High	Medium

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
						an inertia response					
Stability	**RoCoF suppression**	Inertia	<3 s	SG SC GFM GFL BESS	The same as above. Note that GFL BESS can play a part although they cannot provide inertial contribution. Further insights may also be provided in Topic 1.	The same as above The RoCoF withstand capability of installed SG/SC and GFM is not very well known.	High	MMIB PDT MMIB EMT Multi-mass PDT (partially)	No	High	Medium
Stability	**Phase angle jump suppression**	Synchronisation		SG SC GFM	The capabilities and limitations of GFM is not well known. Further insights may also be provided in Topic 1.	The maximum phase angle jump the plant is expected to withstand or suppress is not known	High	SMIB and MMIB EMT	No	High	Medium
Stability	**Grid-forming inverter headroom**	Grid-forming inverters	All time scales	GFM	GFM stability can be degraded if operated current limited. Reserving some headroom below the current rating at all times will ensure that the GFM will not hit the limit during or after the disturbance, and can therefore provide its best performance. Further insights may also be provided in Topic 1.	Lost revenue from energy market will unlikely be a problem for a BESS but will have a higher impact if GFM wind and solar are developed. Also even for a BESS the impact on other revenue stream requiring a high current provision should be considered.	High	SMIB and MMIB EMT	No	High	High
Stability	**Increase available system strength in the power system**	System strength	A few cycles up to a few tens of seconds	SG SC GFM	Operation of very few and dispersed SG/SC		High	MMIB EMT	Yes	High	Medium

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
Stability	**Voltage waveform improvement**	System strength	All time scales	SG SC GFM (capabilities and limitations are not as well understood)	Operation of many GFM nearby, or GFM, SG and SC, and the impact on GFM is not well understood. Potential control interactions between multiple GFM, or multiple GFL and GFM is not widely understood. GFMs are shown to improve the damping of sub-synchronous oscillations. However, the impact will be on frequency components up to its bandwidth and won't be effective on harmonics above ~5-7 order. Also the conditions where GFM may adversely impact voltage waveform is not widely considered. This may include operation at current limitation, high SCR or other conditions not currently known. Further insights may also be		High	MMIB EMT	Yes	High	High

Category	Service	Sub-category	Timeframe	Currently provided by	Technology gap	Other gaps (e.g. network, regulatory)	Criticality in Australia	Assessment methodology	Included in 2021 research	Importance for the 2024 research	Residual importance after the 2024 research
					provided in Topic 1 and 2.						
Stability/power quality	**Damping of electrical super-synchronous resonances**	Damping	A few cycles up to several seconds	SG SC GFM (partially)	GFM can suppress super-synchronous up to its bandwidth. The bandwidth of GFM controls is 300-400 Hz at most, and often lower. Further insights may also be provided in Topic 1.	The same as above This is a very broad range of frequency where the solution for a 400 Hz oscillation will be very different to 4000 Hz	Medium	MMIB EMT	No	Low	High
Variability management	**Active power ramping control**		Several seconds to hours	BESS PHES	Wind and solar with better ramping control capability (performance uncertainty)	As the system strength declines, the correlation between active and reactive power, hence voltage and frequency will increase. This means that a large and rapid change in active power could disturb the voltages even without a fault.	High	PDT and EMT MMIB	No	Low	High

Appendix B 2034 Simplified NEM Topology



Appendix C Study results

These are supplied in separate files due to their large size.