2023 Inertia Report

December 2023

A report for the National Electricity Market

Important notice

Purpose

The purpose of this publication is to report on the boundaries of the inertia sub-networks, inertia requirements for each inertia sub-network, and AEMO's assessment of any identified inertia shortfalls for the coming five-year period for the National Electricity Market. AEMO publishes this 2023 Inertia Report in accordance with clause 5.20.5 of the National Electricity Rules. This publication is generally based on information available to AEMO as at November 2023 unless otherwise indicated.

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Version control

Version	Release date	Changes
1.0	1/12/2023	Initial release.

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Executive summary

AEMO has assessed inertia needs in the National Electricity Market (NEM) over the coming five years, and has not identified any new shortfalls. The magnitude of several existing shortfalls has been reduced, or shortfalls deferred, and all active shortfalls in the 2023-24 financial year are currently being managed through network support agreements.

Table 1 presents a summary of these findings for each region. AEMO will continue to work closely with each network business to support remediation activities.

Table 1 Summary of inertia shortfalls from the 2023 assessment

Region	Inertia shortfall
New South Wales 	**AEMO has not identified any inertia shortfalls in New South Wales.** Inertia levels are expected to decline, however strong interconnection makes this region unlikely to island. **No shortfalls were identified in a combined New South Wales and Queensland region.** While available inertia declines over the horizon, typical levels remain sufficient to meet secure operating requirements across the five-year outlook period.
Queensland 	**The existing inertia shortfall in Queensland has been deferred by one year**. AEMO is now declaring a shortfall of up to 1,660 megawatts seconds (MWs) from 2027-28. This delay reflects changes to the delivery timing of several major generation, transmission and renewable energy zone (REZ) projects which have combined to increase synchronous generation in the short term.
South Australia 	**Support contracts are in place to address South Australian shortfalls until July 2024.** This reflects approximately 360 megawatts (MW) of Fast Frequency Response (FFR) contracts to in place to address a shortfall declared in the 2022 *Inertia Report*. **A 500 MWs shortfall emerges from 1 July 2024 until Project EnergyConnect (PEC) Stage 2 is operational.** This shortfall could be met by an equivalent quantity of FFR contracts. AEMO does not consider South Australia sufficiently likely to island once PEC Stage 2 is commissioned, and protection is in place to manage a non-credible loss of interconnection.
Tasmania 	**Support contracts are in place to address Tasmanian shortfalls until April 2024.** This reflects 2,350 MWs of support contracts in place to address a previously declared shortfall. **A 1,880 MWs shortfall emerges from 1 April 2024** and climbs to 2,500 MWs across the five-year study period. TasNetworks is progressing further arrangements to cover the period until at least December 2025, while long-term options are being considered.
Victoria 	**AEMO has not identified any inertia shortfalls in Victoria.** Inertia levels are expected to decline, however strong interconnection means Victoria is not sufficiently likely to island. **No shortfalls were identified in a combined Victoria and South Australia region.** The previously identified shortfall for this grouping is no longer expected, following joint planning to better reflect separation modes and their associated network configuration at the border.

This assessment applies the latest modelling insights, frequency standards, and market reforms

AEMO's 2023 inertia studies have built on recent improvements in power system monitoring and analysis to better reflect the behaviour of demand in response to events on the network. These improvements, coupled with recent amendments to the Frequency Operating Standard (FOS), have generally revealed the need for regions to carry more inertia than previously thought.

However, while inertia requirements have become more onerous, and inertia is still expected to decline significantly across all regions in the longer term, the near-term availability of inertia has improved in this report. This represents a short deferral, driven by changed delivery timing for several major generation, transmission, and REZ projects. The changes have driven higher utilisation of synchronous generating units in short-term models; and a correspondingly higher expectation of available inertia.

The 2023 inertia studies also considered the impact of the new, very fast (1-second) frequency control market, which commenced operation on 9 October 2023. As capacity is progressively released into this market, it may further supplement the levels of inertia that must be maintained in each region.

All analysis in the 2023 *Inertia Report* is based on the latest available inputs and results from the Draft 2024 *Integrated System Plan* (ISP) *Step Change* scenario[1].

Proactive and coordinated investment will be critical to delivering sufficient inertia over time

AEMO expects that a variety of solutions may be feasible to address the inertia shortfalls identified in this report, and those that will emerge beyond the current five-year study horizon. These options may include inertia provided by synchronous generating units, FFR providers such as batteries, or by installing high-inertia devices such as synchronous condensers fitted with flywheels.

Investments that are being progressed by transmission network service providers (TNSPs) under the system strength framework may provide a substantial opportunity to deliver inertia using the same technical resource, and at a minimal incremental cost[2]. For example, flywheels could be added to any newly purchased synchronous condensers to deliver both inertia and fault current services, while FFR capabilities may be available from the same grid-forming technology being used to accommodate and stabilise future inverter-based resources (IBR).

While this optimisation is possible under the current planning arrangements, the Australian Energy Market Commission (AEMC) is also considering changes to the inertia framework that may streamline this in future[3].

AEMO will continue to advocate for proactive, efficient, and coordinated investment across all system security services.

AEMO is seeking feedback on key inputs for the 2024 inertia assessment

AEMO takes a consultative approach to reviewing inertia requirements and shortfalls each year and intends to use feedback on each annual report to inform future reports. Stakeholders are welcome to provide feedback to planning@aemo.com.au on the matters considered in this report.

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[1] Final revisions ahead of publishing the Draft 2024 ISP in may result in minor changes compared with the modelling inputs used in this report.

[2] Anecdotally, AEMO understands that the incremental costs of adding a typical 1,000 MWs flywheel to an synchronous condenser are in the order of approximately 3% if the decision is made up front. Retrofitting a flywheel is understood to be substantially more expensive.

[3] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

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1 Introduction

In the context of the power system, inertia describes an immediate and inherent electrical response from connected devices that acts to oppose changes in frequency. Ensuring sufficient levels of inertia are available allows the power system to resist large changes in frequency that can arise following a contingency event.

Each year, AEMO assesses the requirements and projected availability of inertia, and declares inertia shortfalls in response to any requirements that are not expected to be met over the coming five-year outlook period. This assessment is typically conducted on a regional basis, however AEMO also considers potential sub-networks and regional groupings where necessary to capture the most likely separation points on the network.

1.1 Scope of analysis

This report provides AEMO's 2023 assessment of inertia requirements and shortfalls. It covers the five-year period from December 2023 to December 2028 inclusive and has been produced in accordance with the Inertia Requirements Methodology[4].

In completing these assessments, AEMO has reviewed the inertia requirements for each sub-network[5] and then undertaken a suite of market modelling studies to estimate the typical levels of inertia expected under system normal and islanded operating conditions. 'Typical' in this context refers to the 99th percentile level of availability.

AEMO has conducted market modelling on a financial year basis, and all analysis leverages the latest available inputs and results from the *Step Change* scenario of the Draft 2024 *Integrated System Plan* (ISP)[6]. Further details on the market modelling approach are presented in Appendix A2.

Where a shortfall is identified, AEMO has attempted to quantify the relationship between inertia and Fast Frequency Response (FFR) as a means of providing additional flexibility when identifying potential remediation options. Local network service providers (NSPs) must then use reasonable endeavours to deliver services that address any declared shortfall.

Inertia requirements

AEMO assesses inertia shortfalls against two distinct levels of requirement:

- **the minimum threshold level of inertia**, being the minimum level of inertia required to operate an inertia sub-network in a satisfactory operating state when the inertia sub-network is islanded; and
- **the secure operating level of inertia**, being the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.

In determining these requirements, AEMO considers the largest relevant credible contingency event, any consequential demand-side response, the levels of frequency control ancillary services (FCAS) available, and AEMO's operational procedures for periods where regions are islanded or at risk of islanding. Further details are available in Appendix A1.2.

[4] AEMO. Inertia Requirements Methodology. July 2018. At https://aemo.com.au/ /media/files/electricity/nem/security_and_reliability/system-security-market-frameworks review/2018/inertia_requirements_methodology_published.pdf?la=en.

[5] AEMO has not declared any additional inertia sub-networks beyond the existing regional boundaries of the National Electricity Market (NEM).

[6] Final revisions ahead of publishing the Draft 2024 ISP in may result in minor changes compared with the modelling inputs used in this report.

1.2 Trends impacting inertia assessments

The National Electricity Market (NEM) is changing at a speed and scale never before seen, transforming the way electricity is generated, transported, and consumed. The pace of this change is still accelerating, and traditional ways of operating are being challenged, as system security and reliability become increasingly complex.

As the system moves away from a historical dependence on synchronous generation, the energy future is expected to be built on low-cost renewable energy, dynamic firming technology, new network infrastructure, and adaptive operating strategies. This shift will have a significant impact on the severity and timing of inertia requirements, shortfalls, and investment needs.

Changes in synchronous generation and consumer energy resources (CER) are driving inertia requirements and availability

Many critical system security needs were once met by the natural properties of a synchronous generation fleet. These were typically located in centralised locations, were coupled with predictable demand patterns, and allowed the power system to operate comfortably inside its technical envelope. However, the energy transition is increasingly driving the system to operate closer to its boundaries, and the inertia services previously available in abundance from synchronous plant are diminishing as that plant is progressively displaced or withdrawn.

Rapid increases in CER also present challenges for frequency management, both through ramping events (where weather patterns produce sudden change in the demand seen by the transmission network), and through larger contingency sizes (such as where CER trips sympathetically and increase the impact of a nearby network event).

The 2023 inertia studies have been able to build on improved monitoring, modelling, and operational experience to better understand the levels of inertia available on the demand side; and to consider the behaviour of today's demand profile in response to rapid voltage changes on the network. These improvements impact the calculation of inertia requirements, and have generally revealed a need for more inertia than previously anticipated.

New and emerging technologies may reduce the need for synchronous inertia

Inertia is most often associated with synchronous machines, which have large spinning turbines and/or rotors whose rotation is synchronised to the frequency of the power system. These components are heavy, typically weighing tens or hundreds of tonnes, and provide mechanical inertia linked to the energy of their rotating masses.

Inverter-based resources (IBR) are typically interfaced with the power system through electronic devices rather than electro-magnetic coupling, and do not generally supply inertia as an inherent characteristic. However, it is possible for some IBR to provide an emulated inertial response through appropriate designs and controls. This type of synthetic inertial response can include a spectrum of services that differ in how quickly they can accurately detect a frequency disturbance, and the profile of their response to it.

While synthetic inertial response could theoretically replace synchronous inertia for the purposes of frequency management, there is not yet sufficient modelling or real-world experience available to quantify the implications and interactions present in a system or assess whether a system such as the NEM could operate effectively fully reliant on synthetic inertial response or FFR providers.

AEMO's assessment of inertia separately considers the response of synchronous generation (inertia), and the contribution of FFR through contracted providers or the 1-second FCAS market.

Real-time inertia measurement may provide a better understanding of available inertia

AEMO's 2023 inertia studies build on recent improvements in power system modelling and analysis to better reflect the behaviour of demand in response to events on the network. While this captures the impact that demand has on the level of inertia *needed*, there remains limited visibility of the impact that demand has on the expected levels of inertia *available*.

AEMO is exploring options to improve the accuracy of its inertia availability estimates, both operationally and across the planning timeframes. To support this, AEMO is participating in a real-time inertia measurement trial, funded through the Australian Renewable Energy Agency (ARENA)[7]. The trial seeks to measure available inertia by creating small frequency deviations at Neoen's Victorian Big Battery, and then analysing the resulting frequency deviations at different locations. The trial employs processes and devices developed by Reactive Technologies, and is expected to conclude in March 2024.

Findings from the work may inform future inertia shortfall calculations; and support improved power system operations under future low or variable inertia conditions.

New frequency standards, obligations, and markets are now in place

Inertia services are only one in a portfolio of frequency management tools that are currently embedded or being progressed through regulatory reforms. While inertia has long complemented the frequency control markets, new tools and standards have been introduced that also cater to needs in the sub 6-second range, where inertia was previously the primary tool:

- A revised Frequency Operating Standard (FOS) became effective in October 2023, and now specifies a maximum rate of change of frequency (RoCoF) of 1 hertz per second (Hz/s) for the mainland and 3 Hz/s for Tasmania.
- Mandatory primary frequency response (PFR) requirements were introduced that mandate provision of PFR services from generating units with the ability to provide them.
- A new very fast (1-second) frequency control market went live on 9 October 2023, and capacity is being progressively released.

These new services and reforms have acted to offset the levels of inertia otherwise required in each region, and AEMO has considered their impacts when assessing requirements and shortfalls for this 2023 *Inertia Report*.

Further market reforms are underway to improve security frameworks in the NEM

The Australian Energy Market Commission (AEMC) is considering options to improve market arrangements for the provision of security services[8]. The AEMC released an initial draft determination for this project in late 2022, but proposed an alternative direction in May 2023 to deliver more immediate solutions. The AEMC is currently considering submissions on its revised directions paper and expects to publish a final determination in March 2024.

[7] See https://arena.gov.au/projects/reactive-technologies-system-inertia-measurement-demonstration/ and https://aemo.com.au/en/initiatives/trials-and-initiatives/victorian-inertia-measurement-trial.

[8] See https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

1.3 Structure of this report

The 2023 *Inertia Report* contains the following information:

- For each region or combined region, AEMO's assessment of inertia requirements and shortfalls:
  - New South Wales (Section 2.1).
  - Queensland (Section 2.2).
  - South Australia (Section 2.3).
  - Tasmania (Section 2.4).
  - Victoria (Section 2.5).
  - New South Wales and Queensland combined (Section 2.6).
  - South Australia and Victoria combined (Section 2.7).
- An overview of next steps related to the findings in this report (Section 3).
- An overview of the methodology and inputs used to prepare this report (Appendix A1).
- An overview of the market modelling assumptions used in preparing this report (Appendix A2).

2 Inertia assessment

2.1 New South Wales

AEMO has not identified any new inertia shortfalls in New South Wales

AEMO has assessed inertia requirements and expected availability for New South Wales over a five-year outlook period. These assessments are based on inputs and modelling for the Draft 2024 ISP *Step Change* scenario[9]. Appendix A1 provides further detail on the inputs, assumptions, and methodology used. Inertia in New South Wales will decline over the five-year outlook period until expected development in the Central-West Orana Renewable Energy Zone (REZ) adds additional synchronous condensers that may provide additional inertia to the region.

AEMO has also assessed a combined island covering both New South Wales and Queensland[10], but did not identify any additional inertia shortfalls. Further details are presented in Section 2.6.

Inertia assessment for New South Wales

AEMO's inertia assessment for New South Wales is summarised in Table 2. There is an small increase in available inertia in 2024-25 associated with the installation of synchronous condensers as part of Project EnergyConnect (PEC) Stage 2. From then, available inertia generally decreases until 2027-28 when seven 250 megavolt amperes reactive (MVAr) synchronous condensers are expected to be available as part of the Central-West Orana REZ development[11].

The 2022 assessment concluded that an inertia deficit could emerge in New South Wales as early as 2027-28. However, changes in the expected timing of several major generation, transmission, and REZ development projects have increased the modelled levels of synchronous generation being dispatched under typical operating conditions. This has resulted in higher levels of available inertia under a range of operating conditions.

The New South Wales inertia requirements have remained unchanged from those used in the 2022 report.

AEMO has not assessed the remediation relationship between inertia and contracted FFR providers in New South Wales as no deficits have been identified. Curves of this type are available for Queensland in Section 2.2.

Table 2 Inertia projections and requirements for New South Wales

For an islanded New South Wales region	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Minimum threshold level (megawatt seconds (MWs))	10,000	10,000	10,000	10,000	10,000	10,000
Secure operating level (MWs)	12,500	12,500	12,500	12,500	12,500	12,500
Available inertia 99% of the time (MWs)	21,381	22,295	14,697	14,945	26,748	23,223
Calculated inertia deficit (MWs)	0	0	0	0	0	0
Likelihood of islanding	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
Declared inertia shortfall	-	-	-	-	-	-

[9] Final revisions ahead of Draft 2024 ISP publication may result in minor changes compared with the modelling inputs used in this report.

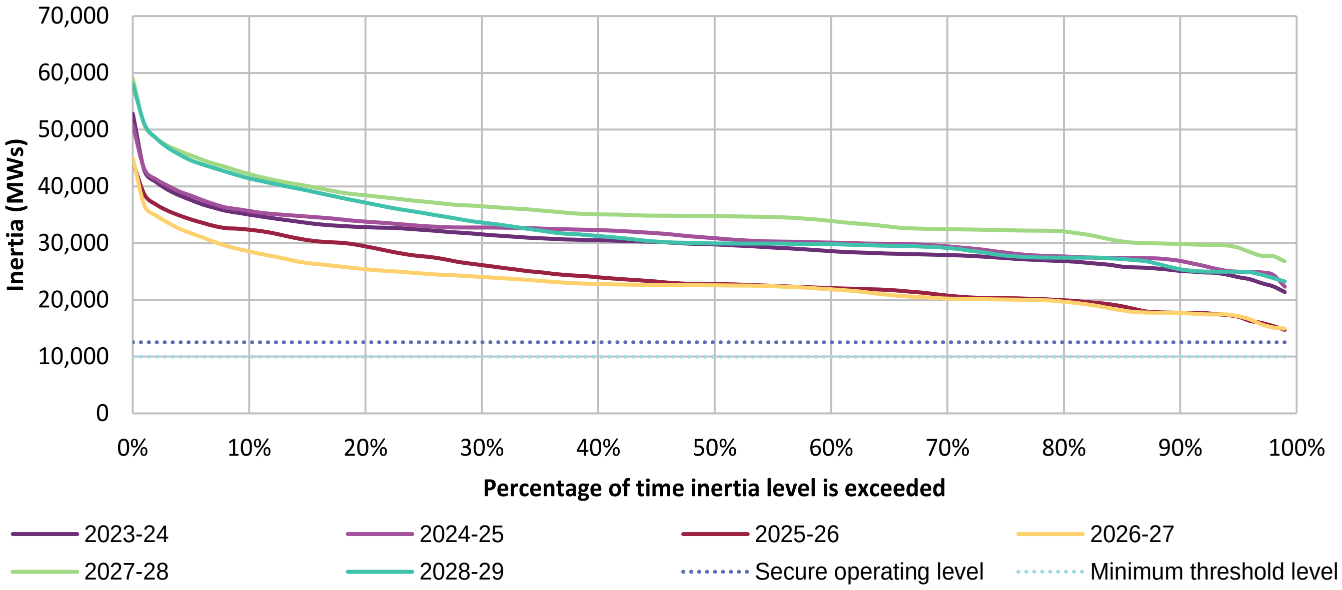
[10] A section of network in south-western New South Wales is considered likely to remain connected to the South Australia and Victoria regions.

[11] AEMO Transmission Augmentation Information. August 2023. At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/transmission-augmentation-information.

Inertia availability results

Figure 1 presents the modelled inertia duration curves for New South Wales over a five-year horizon. This highlights the stepwise decline in the expected levels of available inertia until 2027-28 where available inertia increases with addition of synchronous condensers in Central-West Orana REZ.

Figure 1 Projected levels of inertia available in New South Wales, *Step Change* scenario



2.2 Queensland

AEMO has identified a change in the inertia shortfall previously identified for Queensland, which now occurs from 2027-28 at a level of up to 1,660 megawatt seconds (MWs). This is linked to changes in the announced timing of several major generation and transmission projects, which have impacted expected generation dispatch patterns.

AEMO has assessed inertia requirements and expected availability in Queensland over a five-year outlook period. These assessments are consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario[12]. Appendix A1 provides further detail on the inputs, assumptions, and methodology used.

AEMO has also assessed a combined island covering both New South Wales and Queensland[13], but did not identify any additional inertia shortfalls. Further details are presented in Section 2.6.

Updates to the inertia requirements

As part of the 2023 assessment, AEMO has reviewed the inertia requirements for Queensland, and has increased the minimum operating level, and decreased the secure operating level. This reflects:

- The introduction of more onerous requirements in the FOS, which specifies a 1 Hz/s RoCoF standard for all mainland.
- The commencement of a new 1-second FCAS market, which delivers additional pre-contingent frequency control services that act to decrease the secure operating level.
- The latest models of load and distributed photovoltaic (DPV) generation developed as part of AEMO's power system model development[14] which more accurately describe the dynamic response of these inputs, and impacts results differently in each region.

AEMO has not declared any inertia sub-networks within Queensland, however will continue to work with Powerlink to identify potential intra-regional separation modes that might be candidates for study in future years.

The inertia requirements for Queensland

Since the 2022 *Inertia Report*, a new 1-second FCAS market has commenced operation, and updated delivery timing for several major projects across the NEM have increased the modelled utilisation of synchronous generating units in the near term.

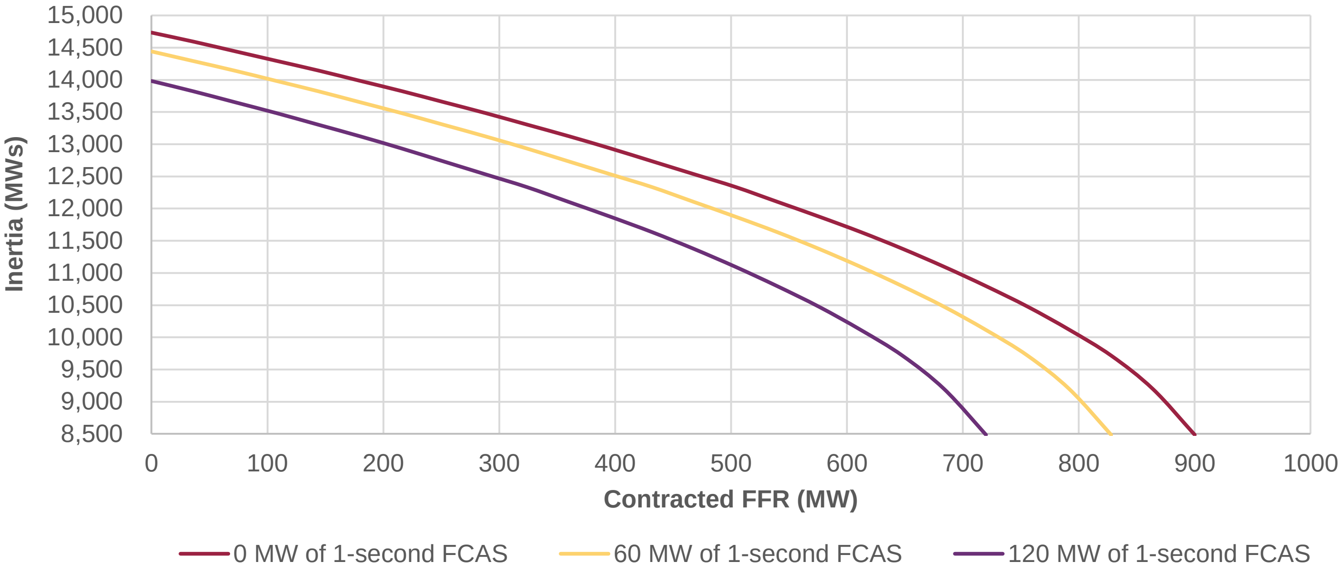
AEMO has considered these changes in updating the secure operating requirements for Queensland. The updated requirements have been defined in terms of inertia, contracted FFR, and available 1-second FCAS, as presented in Figure 2. The curves define a set of operating points that would ensure the system remains in a satisfactory state from a frequency perspective, following a credible contingency, and when specific levels of 1-second FCAS are available.

[12] Final revisions ahead of the Draft 2024 ISP in may result in minor changes compared with the modelling inputs used in this report.

[13] A section of network in south-western New South Wales is considered likely to remain connected to the South Australia and Victoria regions.

[14] AEMO. PSS®E models for load and distributed PV in the NEM. November 2022. At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/power-system-model-development.

Figure 2 Relationship between inertia and fast frequency response in Queensland



The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

When assessing shortfalls in Queensland, an operating point with no contracted FFR, and 60 megawatts (MW) of 1-second FCAS has been assumed – which is the current amount of 1-second raise FCAS currently registered in Queensland. This is equivalent to 77 MW of contracted FFR[15]. Using this operating point reflects that during islanded operation, local FCAS prices are likely to incentivise capacity to become available.

Assuming a lower (or derated) value would increase obligations on the transmission network service provider (TNSP) and require them to either contract with an equivalent amount of FFR outside the market, or procure other inertia services that reduce the demand for 1-second FCAS. In both cases, the amount of derating assumed becomes self fulfilling by reducing either the demand or available providers in the 1-second market.

AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review inertia requirements annually.

Inertia assessment for Queensland

AEMO's 2023 inertia assessment for Queensland is summarised in Table 3. The results identify an expected inertia deficit of between 1,660 MWs and 1,390 MWs in 2027-28 and 2028-29, under conditions where Queensland is operating as an island and 60 MW of 1-second FCAS is available.

The 2022 assessment declared an inertia shortfall of up to 10,352 MWs from 2026 onwards. However, since that report, changes in the expected timing of several major generation, transmission, and REZ development projects have increased the modelled utilisation of synchronous generating units during typical operating conditions over the five-year study period. This represents a deferred onset of the shortfall, rather than a long-term reduction.

[15] See Section A1.4.1 for details on this translation.

Table 3 Inertia projections and requirements for Queensland

For an islanded Queensland region	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Assumed level of 1-second FCAS (MW)	60	60	60	60	60	60
Minimum threshold level of inertia (MWs)	12,700	12,700	12,700	12,700	12,700	12,700
Secure operating level of inertia (MWs)	14,400	14,400	14,400	14,400	14,400	14,400
Available inertia 99% of the time (MWs)	17,811	18,731	19,512	19,147	12,743	13,015
Calculated inertia deficit (MWs)	0	0	0	0	1,657	1,385
Likelihood of islanding	Likely	Likely	Likely	Likely	Likely	Likely
Declarable inertia shortfall (MWs)[A]	-	-	-	-	1,660	1,390

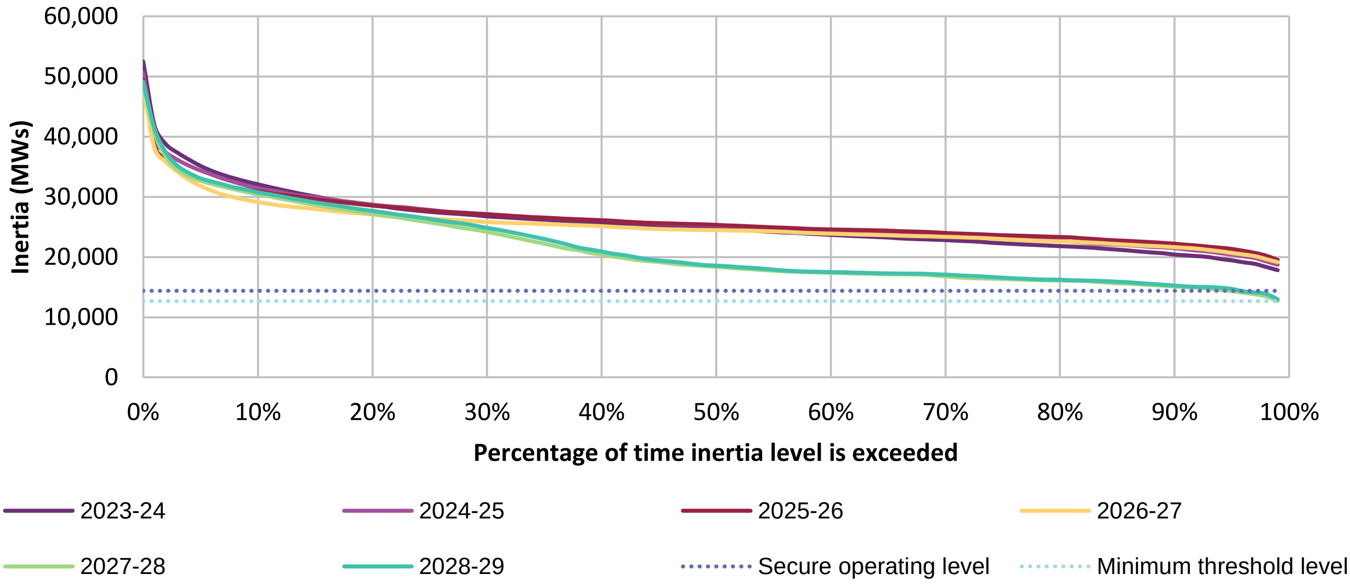
A. Declarable inertia shortfall is the calculated inertia deficit, rounded up to the nearest 10 MWs.

AEMO will continue to work closely with Powerlink to support remediation and explore options to optimise this need alongside existing system strength investment activities.

Inertia availability results

Figure 3 presents the modelled inertia duration curves for Queensland over a five-year horizon. This highlights the general decline in the expected levels of available inertia and identifies that up to 5% of periods may have insufficient local inertia to meet the secure operating level from 2027-28.

Figure 3 Projected levels of inertia available in Queensland, *Step Change* scenario



2.3 South Australia

ElectraNet now has sufficient FFR contracts in place to address existing inertia shortfalls until 1 July 2024. AEMO is declaring a reduced shortfall of 500 MWs from 1 July 2024 until PEC Stage 2 is operational and appropriate control schemes are in place. This shortfall could be met by an equivalent quantity of FFR contracts, or by further registrations in the 1-second FCAS market.

AEMO has assessed inertia requirements and expected availability in South Australia over a five-year outlook period. The assessments are consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario. AEMO no longer considers South Australia sufficiently likely to island once additional interconnection is in place with New South Wales and necessary protection schemes are in place to manage the non-credible loss of either PEC or the Heywood Interconnector.

AEMO has also assessed a combined island covering both Victoria and South Australia, but did not identify any additional inertia shortfalls. Further details are presented in Section 2.7.

Updates to the inertia requirements

As part of the 2023 assessment, AEMO has reviewed the inertia requirements for South Australia, and has increased the minimum operating level, and decreased the secure operating level in response. This reflects:

- The introduction of more onerous requirements in the FOS, which specifies a 1 Hz/s RoCoF standard for all mainland NEM regions and acts to increase both the minimum and secure levels of inertia.
- The commencement of a new 1-second FCAS market, which delivers additional pre-contingent frequency control services that act to decrease the secure operating level.
- The latest models of load and DPV developed as part of AEMO's power system model development[16] which more accurately describe the dynamic response of these inputs, and impacts results differently in each region.

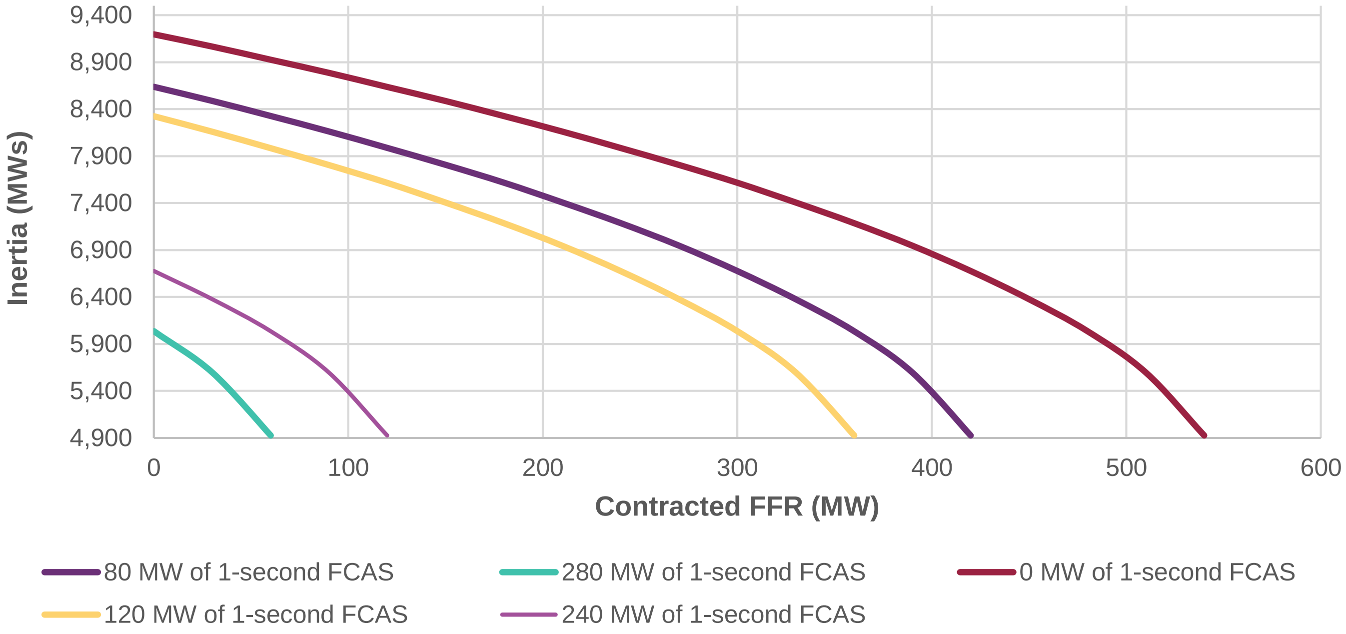
The inertia requirements for South Australia

AEMO has considered the above changes in updating the secure operating requirements for South Australia. The updated requirements have been defined in terms of inertia, contracted FFR, and available 1-second FCAS, as presented in Figure 4. The curves define a set of operating points that would ensure the system remains in a satisfactory state from a frequency perspective, following a credible contingency, and when specific levels of 1-second FCAS are available.

The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

[16] AEMO. PSS®E models for load and distributed PV in the NEM. November 2022. At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/power-system-model-development.

Figure 4 Relationship between inertia and fast frequency response in South Australia



When assessing shortfalls in South Australia, AEMO used two operating points:

- For 2023-24, an operating point with 360 MW of contracted FFR, and 80 MW of 1-second FCAS, was assumed. This represents the existing TNSP contracted capacity, and the volume of uncontracted providers registered in the 1-second raise FCAS market in South Australia[17].
- From 1 July 2024, an operating point with no contracted FFR, and 240 MW of 1-second FCAS, was assumed. This represents the volume of providers registered in the 1-second raise FCAS market, following expiry of ElectraNet's existing contracts. This increases overall from the previous 1-second FCAS assumption as some capacity was registered and contracted in 2023-24.

Inertia requirements from 1 July 2024 onwards could be reduced by extending existing FFR contracts, new proponents registering in the 1-second FCAS market, or the previously contracted parties themselves registering in the 1-second market. AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review inertia requirements annually.

Inertia assessment for South Australia

AEMO's inertia assessment for South Australia is summarised in Table 4, and identifies deficits from 2024-25. This represents a slight increase in magnitude compared with the previous report, and is largely driven by inclusion of the new frequency operating standards, introduction of a 1-second FCAS market, and improved demand side modelling analysis.

ElectraNet has sufficient inertia support contracts in place to address the identified deficit until July 2024, and AEMO does not consider South Australia to be sufficiently likely to island following completion of PEC Stage 2. Therefore, AEMO is only declaring 500 MWs shortfall from July 2024 until PEC Stage 2 is complete and necessary schemes are in place to manage the non-credible loss of either PEC or the Heywood Interconnector.

[17] More details on the translation between contracted FFR and 1-second FCAS contributions is provided in Appendix A1.4.1.

Table 4 Inertia projections and requirements for South Australia

For an islanded South Australia region	2023-24	2024-25 (Early)[A]	2024-25 (Late)[A]	2025-26	2026-27	2027-28	2028-29
Assumed level of 1-second FCAS (MW)	80	240	240	240	240	240	240
Existing contracted FFR (MW)	360	-	-	-	-	-	-
Minimum threshold level of inertia (MWs)	4,600	5,200	5,200	5,200	5,200	5,200	5,200
Secure operating level of inertia (MWs)	6,000	6,700	6,700	6,700	6,700	6,700	6,700
Available inertia 99% of the time (MWs)	6,200	6,200	4,400	4,400	4,400	4,400	4,400
Calculated inertia deficit (MWs)	-	500	2,300	2,300	2,300	2,300	2,300
Likelihood of islanding	Likely	Likely	Unlikely[B]	Unlikely[B]	Unlikely[B]	Unlikely[B]	Unlikely[B]
Declarable inertia shortfall (MWs)	-	500	-	-	-	-	-

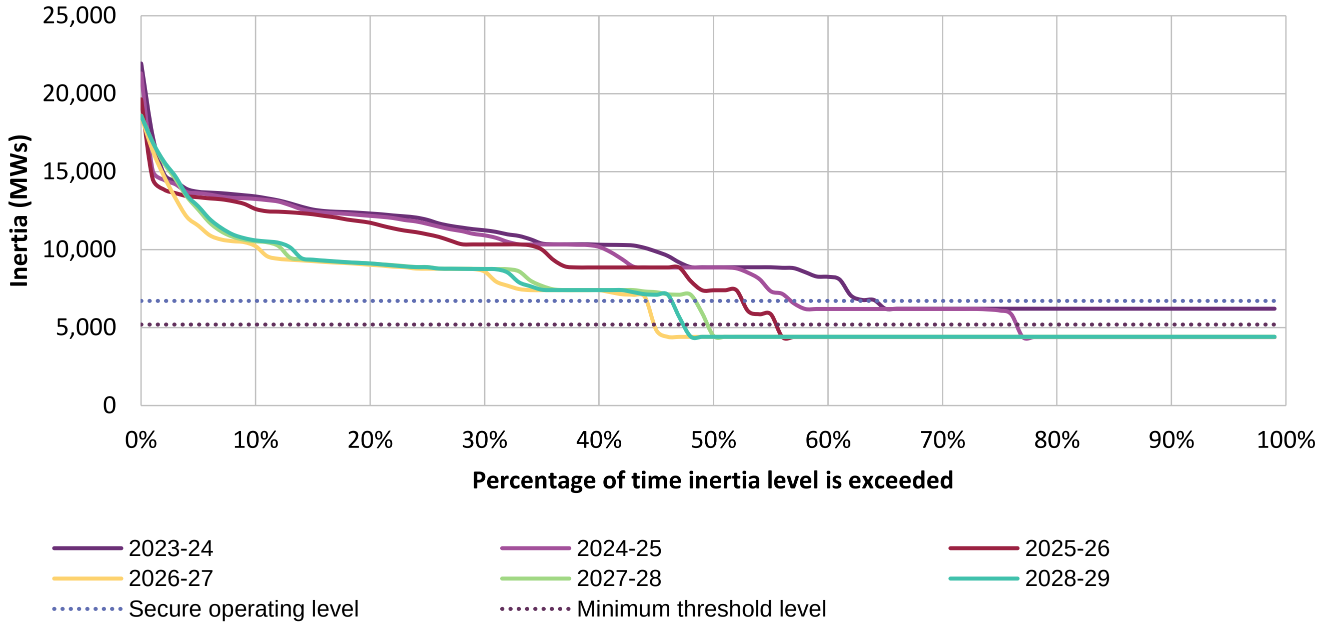
A. A significant transition happens within this year, following the expected commissioning of PEC Stage 2, and associated control schemes. As such, results for 2024-25 have been split into values that apply before and after PEC commissioning.
B. AEMO does not consider South Australia to be sufficiently likely to island following the expected commissioning of PEC Stage 2 and necessary protection schemes are in place to manage the non-credible loss of either PEC itself or the Heywood Interconnector.

AEMO will work closely with ElectraNet to support remediation and explore options to optimise this alongside existing system strength investment activities.

Inertia availability results

Figure 5 presents the modelled inertia duration curves for South Australia over a five-year horizon. This highlights the general decline in the expected levels of available inertia and identifies that over 50% of periods may have insufficient local inertia to meet the secure operating level by 2026-27.

Figure 5 Projected inertia for the five-year outlook, *Step Change* scenario, South Australia[A]



A. This analysis assumes that at least two synchronous generating units will remain online to support other security requirements in South Australia until PEC Stage 2 is commissioned, and a control scheme is in place to manage the non-credible loss of PEC or the Heywood Interconnector.

2.4 Tasmania

TasNetworks has sufficient inertia support contracts in place to address existing inertia shortfalls until April 2024. Beyond that time, a reduced shortfall of 1,880 MWs has been identified for 2024-25, which rises to 2,500 MWs across the five-year period.

AEMO has assessed inertia requirements and expected availability in Tasmania over a five-year outlook period. These assessments are consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario[18]. Appendix A1 provides further detail on the inputs, assumptions, and methodology used.

Inertia assessment for Tasmania

AEMO's inertia assessment for Tasmania is summarised in Table 5. The results identify deficits in all years across the study horizon. The magnitude of these deficits has reduced compared to those in the 2022 *Inertia Report*. This is due to updated delivery timing for several mainland generation, transmission and REZ development projects which have consequently increased the expected dispatch and export of synchronous generation from Tasmania.

TasNetworks has inertia support agreements already in place that are sufficient to cover the identified shortfall until their expiry in April 2024, beyond which a shortfall reappears. TasNetworks is progressing arrangements to cover a period until at least December 2025, while longer-term options are being considered.

The inertia requirements in Tasmania have not been reviewed for this report because the impacts to DPV modelling are less pronounced in Tasmania, and there was no change to the FOS in Tasmania.

AEMO will continue to work closely with TasNetworks to support remediation and explore options to optimise this need with existing system strength investment activities.

Table 5 Inertia projections and requirements for Tasmania

For an islanded Tasmania region	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Minimum threshold level of inertia (MWs)	3,200	3,200	3,200	3,200	3,200	3,200
Secure operating level of inertia (MWs)	3,800	3,800	3,800	3,800	3,800	3,800
Available inertia 99% of the time (MWs)	1,934	1,926	1,965	1,230	1,291	1,291
Calculated inertia deficit (MWs)	1,866	1,874	1,835	2,570	2,509	2,509
Likelihood of islanding	Always	Always	Always	Always	Always	Always
Existing inertia support contracts	2,350	-	-	-	-	-
Declarable inertia shortfall (MWs)[B]	Contracted	1,880	1,840	2,570	2,510	2,510

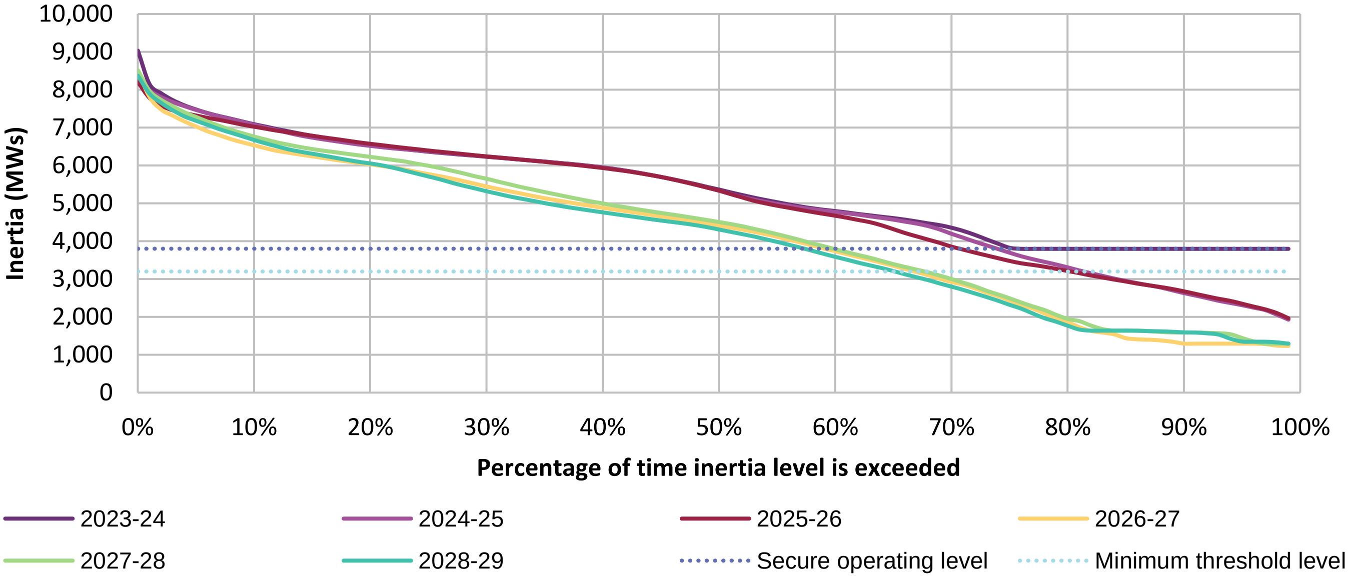
A. Tasmania is always considered an island for inertia because its direct current (DC) interconnection with the mainland NEM does not transport synchronous inertia (although can provide frequency control when sufficient headroom is available).
B. Declarable inertia shortfall is the calculated inertia deficit, rounded up to the nearest 10 MWs.

[18] Final revisions ahead of Draft 2024 ISP publication may result in minor changes compared with the modelling inputs used in this report.

Inertia availability results

Figure 6 presents the modelled inertia duration curves for Tasmania over a five-year horizon. This highlights the decline in the expected levels of available inertia and identifies that up to 42% of periods may have insufficient local inertia to meet the secure operating level by the end of the five-year horizon.

Figure 6 Projected inertia for the five-year outlook, *Step Change* scenario, Tasmania[A]



A. For the dispatch intervals in 2023-24 where the total available inertia falls below the secure operating level, post-processing has been done to indicate that the inertia requirements have been met by the inertia contract in place until April 2024.

2.5 Victoria

AEMO has not identified any inertia shortfalls for Victoria, nor any shortfalls for a combined Victoria and South Australia region.

AEMO has assessed the inertia requirements and expected inertia availability in Victoria over a five-year outlook period. These assessments are consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario[19]. Appendix A1 provides further detail on the inputs, assumptions, and methodology used.

AEMO expects that inertia in Victoria will decline over the five-year outlook period as synchronous generating units withdraw from the market. The region is expected to fall below the secure operating level in over 90% of periods by 2028-29, however no shortfall is being declared because strong interconnection with neighbouring regions means that Victoria is not considered sufficiently likely to island.

AEMO has also assessed a combined island covering both Victoria and South Australia[20], but did not identify any additional inertia shortfalls over the horizon. Further details are presented in Section 2.7.

Updates to the inertia requirements

As part of the 2023 assessment, AEMO has reviewed the inertia requirements for Victoria, and has increased both the minimum operating level and secure operating level in response. This reflects:

- The introduction of more onerous requirements in the FOS, which specifies a 1 Hz/s RoCoF standard for all mainland NEM regions and acts to increase both the minimum and secure levels of inertia.
- The commencement of a new 1-second FCAS market, which delivers additional pre-contingent frequency control services that act to decrease the secure operating level.
- The latest models of load and DPV developed as part of AEMO's power system model development[21] which more accurately describe the dynamic response of these inputs, and impact inertia requirements differently in each region.

The inertia requirements for Victoria

AEMO has considered the above changes in updating the secure operating requirements for Victoria. The updated requirements have been defined in terms of inertia, contracted FFR, and available 1-second FCAS, as presented in Figure 7. The curves define a set of operating points that would ensure the system remains in a satisfactory state from a frequency perspective, following a credible contingency, and when specific levels of 1-second FCAS are available.

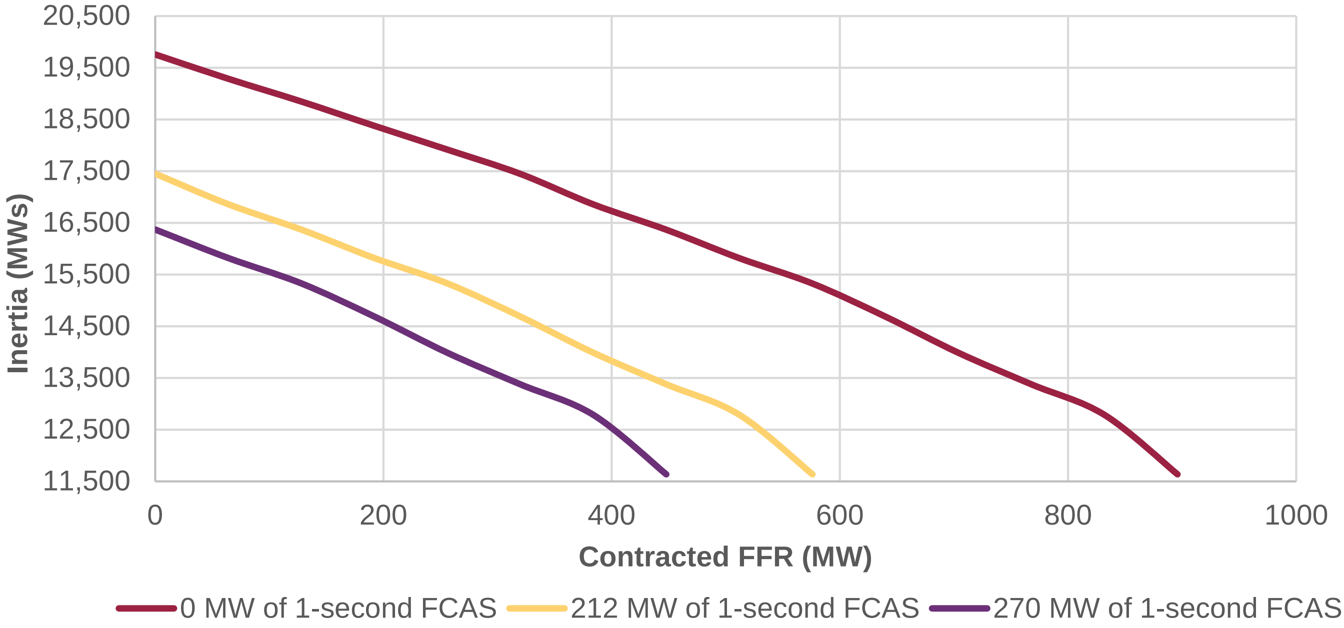
The curves are intended to provide flexibility in the solutions used to address a declared shortfall. For example, an operating point below the curve would indicate a shortfall. This could be remediated by procuring inertia (moving up), contracting FFR services (moving right), or by procuring both services (moving both up and right). The optimal mixture will depend on the size and timing of the shortfall, and the options available in the region.

[19] Final revisions ahead of Draft 2024 ISP publication may result in minor changes compared with the modelling inputs used in this report.

[20] A section of network in south-western New South Wales is considered likely to remain connected to the South Australia and Victoria regions.

[21] AEMO. PSS®E models for load and distributed PV in the NEM. November 2022. At https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/power-system-model-development.

Figure 7 Relationship between inertia and fast frequency response in Victoria



When assessing shortfalls in Victoria, an operating point with no contracted FFR, and 212 MW of 1-second FCAS has been assumed – which is the current amount of 1-second raise FCAS currently registered in Victoria. This is equivalent to 350 MW of contracted FFR[22]. Using this operating point reflects that during islanded operation, local FCAS prices are likely to incentivise capacity to become available.

Assuming a lower (or derated) value would increase obligations on the TNSP and require them to either contract with an equivalent amount of FFR outside the market, or procure other inertia services that reduce the demand for 1-second FCAS. In both cases, the amount of derating assumed becomes self fulfilling by reducing either the demand or available providers in the 1-second market.

AEMO expects that a TNSP should consider the latest amount of registered 1-second FCAS when procuring FFR or inertia services. AEMO will continue to review inertia requirements annually.

Inertia assessment for Victoria

AEMO's inertia assessment for Victoria is summarised in Table 6. The results identify an expected inertia deficit of 7,229 MWs in 2023-24 which grows to 11,288 MWs by 2028-29, under conditions where Victoria is operating as an island and no additional inertia support services are available.

Despite these results, no shortfall is being declared for Victoria because the region is not considered sufficiently likely to island, reflecting both the number and geographic diversity of interconnections between Victoria and neighbouring regions.

[22] See Section A1.4.1 for details on this translation.

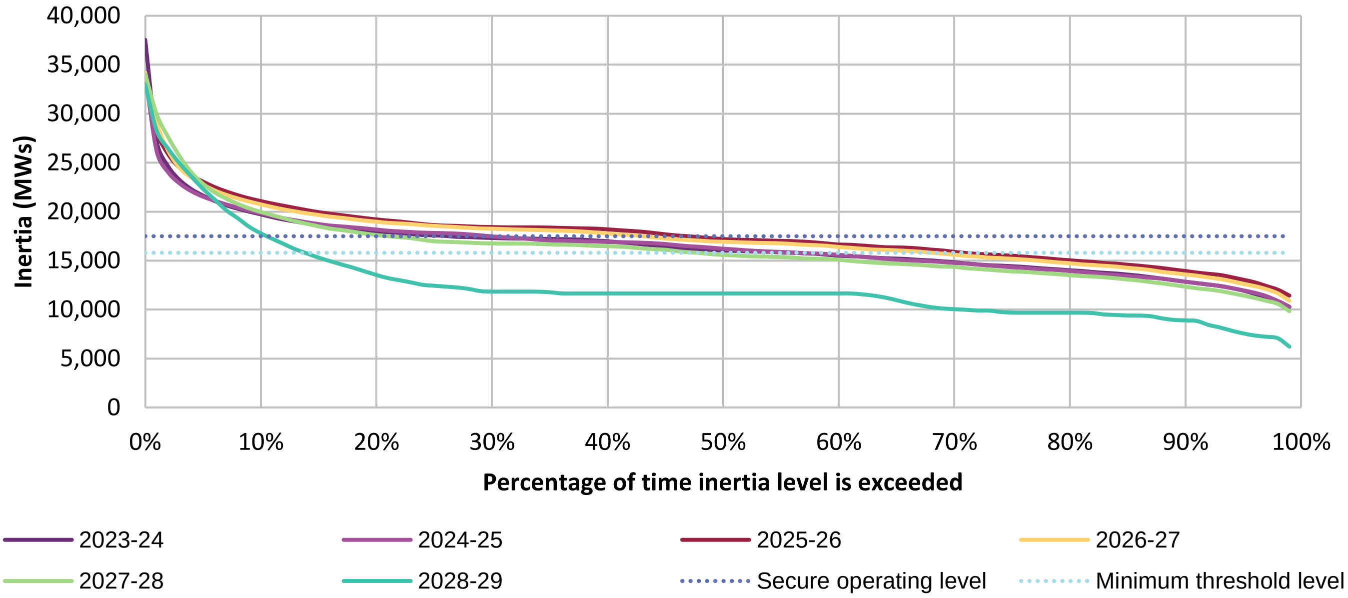
Table 6 Inertia requirements and projections for Victoria

For an islanded Victoria region	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Assumed level of 1-second FCAS (MW)	212	212	212	212	212	212
Minimum threshold level of inertia (MWs)	15,800	15,800	15,800	15,500	15,800	15,800
Secure operating level of inertia (MWs)	17,500	17,500	17,500	17,500	17,500	17,500
Available inertia 99% of the time (MWs)	10,271	10,259	11,428	10,922	9,830	6,212
Calculated inertia deficit (MWs)	7,229	7,241	6,072	6,578	7,670	11,288
Likelihood of islanding	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely	Unlikely
Declarable inertia shortfall	-	-	-	-	-	-

Inertia availability results

Figure 8 presents the modelled inertia duration curves for Victoria over a five-year horizon. This highlights that the region is currently expected to fall below the secure operating level for 73% of the time, increasing to over 90% by 2028-29.

Figure 8 Projected inertia for the five-year outlook, *Step Change* scenario, Victoria



2.6 New South Wales and Queensland

AEMO has not identified any inertia shortfalls for a combined New South Wales and Queensland region.

AEMO has assessed the inertia requirements and expected availability for a combined New South Wales and Queensland region over a five-year outlook period. It remains important to consider these multi-region groupings because several historical separation events have occurred between New South Wales and Victoria, resulting in separate northern and southern islands within the mainland NEM[23].

This assessment is consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario[24], and Appendix A1 provides further detail on the inputs, assumptions, and methodology used.

Inertia assessment for New South Wales and Queensland combined

AEMO's inertia assessment for the combined New South Wales and Queensland region is summarised in Table 7, and does not identify any expected inertia deficits across the outlook period.

While ultimately not relevant in the assessment, AEMO considers that this multi-region grouping would no longer be sufficiently likely to island following commissioning of the HumeLink project near the end of the study horizon.

The inertia requirements for the combined island of New South Wales and Queensland have also been updated aligned with the inertia requirements update for Queensland. Further details can be found in Section 2.2.

Table 7 Inertia requirements and projections for New South Wales and Queensland

For New South Wales and Queensland	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29
Assumed level of 1-second FCAS (MW)	60	60	60	60	60	60
Minimum threshold level of inertia (MWs)	12,700	12,700	12,700	12,700	12,700	12,700
Secure operating level of inertia (MWs)	14,400	14,400	14,400	14,400	14,400	14,400
Available inertia 99% of the time (MWs)	41,466	42,288	34,980	34,309	39,412	36,180
Calculated inertia deficit (MWs)	0	0	0	0	0	0
Likelihood of combined regions islanding	Likely	Likely	Likely	Unlikely[A]		
Declarable inertia shortfall	-	-	-	-		

A. This region combination is no longer considered sufficiently likely to island following HumeLink commissioning when it delivers an additional connection path to the southern NEM regions. Differing assumptions exist for expected completion date, and modelled in-service date for studies from 2026 onwards. Any change in project timing will also affect this change in likelihood.

[23] For example, New South Wales and Victoria separation event on 4 January 2020; see https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separationevent-4-jan-2020.pdf?la=en.

[24] Final revisions ahead of Draft 2024 ISP publication may result in minor changes compared with the modelling inputs used in this report.

2.7 South Australia and Victoria

AEMO has not identified any inertia shortfalls for a combined Victoria and South Australia region. The previously identified shortfall for this group is no longer projected. This follows joint planning work to better reflect likely separation events and their impact on network configuration at the border.

AEMO has assessed the inertia requirements and expected availability for a combined South Australia and Victoria region over a five-year outlook period. It remains important to consider these multi-region groupings because several historical separation events have occurred between New South Wales and Victoria, resulting in separate northern and southern islands within the mainland NEM[25,26]. AEMO considers that this regional group is not sufficiently likely to island following commissioning of the HumeLink project, near the end of the study horizon.

This assessment is consistent with modelling undertaken for the Draft 2024 ISP *Step Change* scenario[27], and Appendix A1 provides further detail on the inputs, assumptions, and methodology used.

Inertia assessment for South Australia and Victoria combined regions islanding

AEMO's inertia assessment for this combined region is summarised in Table 8. The results do not identify any expected inertia shortfalls across the outlook period. AEMO considers that this multi-region grouping would no longer be sufficiently likely to island following commissioning of the HumeLink project near the end of the study horizon which means the identified shortfalls in 2027-28 and 2028-29 are not declared.

Table 8 Inertia requirements and projections for South Australia and Victoria

<table>
<tr><th>For South Australia and Victoria</th><th>2023-24</th><th>2024-25</th><th>2025-26</th><th>2026-27</th><th>2027-28</th><th>2028-29</th></tr>
<tr><td>Assumed level of 1-second FCAS (MW)</td><td>212</td><td>212</td><td>212</td><td>212</td><td>212</td><td>212</td></tr>
<tr><td>Minimum threshold level of inertia (MWs)</td><td>15,800</td><td>15,800</td><td>15,800</td><td>15,800</td><td>15,800</td><td>15,800</td></tr>
<tr><td>Secure operating level of inertia (MWs)</td><td>17,500</td><td>17,500</td><td>17,500</td><td>17,500</td><td>17,500</td><td>17,500</td></tr>
<tr><td>Available inertia 99% of the time (MWs)</td><td>17,598</td><td>17,964</td><td>18,584</td><td>18,032</td><td>17,000</td><td>13,588</td></tr>
<tr><td>Calculated inertia deficit (MWs)</td><td>0</td><td>0</td><td>0</td><td>0</td><td>500</td><td>3,912</td></tr>
<tr><td>Likelihood of combined regions islanding</td><td>Likely</td><td>Likely</td><td>Likely</td><td colspan="3">Unlikely[A]</td></tr>
<tr><td>Declarable inertia shortfall (MWs)</td><td>-</td><td>-</td><td>-</td><td colspan="3">-</td></tr>
</table>

A. This region combination is not considered sufficiently likely to island following HumeLink commissioning when it delivers an additional connection path to the southern NEM regions. Differing assumptions exist for expected completion date, and modelled in-service date for studies from 2026 onwards. Any change in project timing will also affect this change in likelihood.

[25] For example, New South Wales and Victoria separation event on 4 January 2020; see https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separationevent-4-jan-2020.pdf?la=en.

[26] It is likely that part of South West New South Wales would also be part of this Victoria – South Australia island, similar to the event on 4 January 2020.

[27] Final revisions ahead of Draft 2024 ISP publication may result in minor changes compared with the modelling inputs used in this report.

3 Next steps

The 2023 inertia assessment has confirmed previously expected shortfalls, and reduced the magnitude or deferred the timing of others across the five-year outlook period. Table 9 summarises these findings, and AEMO will work closely with the TNSPs to support any remediation activities associated with each shortfall.

AEMO welcomes any comments, questions, or suggestions on this report via planning@aemo.com.au.

Table 9 Summary of new and existing inertia shortfalls

Region	Inertia shortfall
New South Wales 	**AEMO has not identified any inertia shortfalls in New South Wales.** Inertia levels are expected to decline until commissioning of Central-West Orana REZ, however strong interconnection with other regions means New South Wales is not considered sufficiently likely to island. **No shortfalls were identified in a combined New South Wales and Queensland region.** While available inertia declines over the horizon, typical levels remain sufficient to meet secure operating requirements across the five-year outlook period.
Queensland 	**The existing inertia shortfall in Queensland has been reduced and deferred by one year**. AEMO is now declaring a shortfall of up to 1,660 MWs from 2027-28. This delay reflects updates to the delivery timing of several major generation, transmission and REZ development projects which have resulted in utilisation of synchronous generation in the near term.
South Australia 	**Sufficient FFR contracts are in place to address South Australian shortfalls until July 2024.** This reflects that ElectraNet has entered into a range of FFR contracts that total approximately 360 MW. **A 500 MWs shortfall emerges from 1 July 2024 until PEC Stage 2 is operational and necessary protection schemes are in place.** This could be met by an equivalent quantity of FFR contracts, or through increasing levels of registered capacity in the 1-second FCAS market. AEMO does not considers South Australia sufficiently likely to island once PEC Stage 2 is commissioned, and a control scheme is in place to manage the non-credible loss of either PEC itself or the Heywood Interconnector.
Tasmania 	**TasNetworks has addressed existing shortfalls in Tasmania until April 2024.** This relies on existing commercial arrangements capable of delivering approximately 2,350 MWs of inertia. **A shortfall of 1,880 MWs emerges from 1 April 2024** and climbs to over 2,500 MWs across the five-year study period. TasNetworks is progressing further arrangements to cover the period until at least December 2025, while long-term options are being considered.
Victoria 	**AEMO has not identified any inertia shortfalls in Victoria.** Inertia levels are expected to decline substantially across the five-year period, however strong interconnection with neighbouring regions means that Victoria is not considered sufficiently likely to island. **No shortfalls were identified in a combined Victoria and South Australia region.** The previously identified shortfall for this grouping (and allocated to Victoria) is no longer projected. This follows joint planning activities to better reflect separation modes and their associated network configuration at the border. Shortfalls post 2027-28 are not declared on the basis of this islanding event being deemed unlikely after the commissioning of HumeLink.

A1. Inertia methodology and inputs

AEMO has assessed inertia requirements and shortfalls in each region over a five-year outlook period. This appendix provides an overview of the methodology and input data sources used to conduct these studies.

All assessments have been conducted in accordance with the latest Inertia Requirements Methodology[28], and were based on the latest available data at the point where studies were initiated. In most cases, this data cut-off was 1 November 2023. Where possible, all analysis has been based on the latest available inputs and results from the *Step Change* scenario of the Draft 2024 ISP[29].

A1.1 Inertia sub-networks

AEMO must determine boundaries for inertia sub-networks, for which inertia minimum and secure requirements are assessed. AEMO may adjust these boundaries from time to time. Inertia sub-networks must be aligned within the boundaries of a NEM region, or wholly confined within a region[30].

AEMO has not made any adjustments to existing inertia sub-network boundaries, which correspond with the boundaries of NEM regions.

A1.2 Frequency control ancillary services

AEMO's assessment of inertia forecasts and shortfalls accounts for inertia impact from the FCAS markets[31] by assuming that registered participants in the raise and lower 1-second FCAS markets will be available to provide their maximum capability, if they can reasonably be expected to be enabled at the time when the inertia requirements will apply. While it may be considered ambitious to assume the entire 1-second FCAS fleet is available, AEMO considers this is offset by the fact that additional FCAS will be registered over time. Specifics on how the new 1-second FCAS market is included is discussed in A1.4.1

A1.3 Calculating Inertia requirements

Under National Electricity Rules (NER) 5.20B.2, AEMO assesses inertia shortfalls against two distinct levels of requirement:

- **the minimum threshold level of inertia**, being the minimum level of inertia required to operate an inertia sub-network in a satisfactory operating state when the inertia sub-network is islanded; and
- **the secure operating level of inertia**, being the minimum level of inertia required to operate an inertia sub-network in a secure operating state when the inertia sub-network is islanded.

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28 AEMO. Inertia Requirements Methodology. July 2018. At https://aemo.com.au/ /media/files/electricity/nem/security_and_reliability/system-security-market-frameworks review/2018/inertia_requirements_methodology_published.pdf?la=en.

29 Final revisions ahead of publishing the Draft 2024 ISP may result in minor changes compared with the modelling inputs used in this report.

30 NER 5.20B.1

31 For information about the FCAS markets in the NEM, see AEMO's website at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services.

In determining these requirements, AEMO considers the largest relevant credible contingency event, any consequential demand-side response, the levels of FCAS available, and AEMO's operational procedures for periods where regions are islanded or at risk of islanding.

In 2023, the inertia requirements have been reviewed to accommodate several changes:

- Updated DPV/load models which also capture momentary cessation characteristics as well as overall disconnection after a fault.
- New 1-second FCAS market which can take the place of contracted FFR in inertia.
- New FOS including 1 Hz/s RoCoF for islanded conditions for NEM mainland and 3 Hz/s for Tasmania.
- More large-scale IBR susceptible to fault ride-through[32].

A two-stage approach is used to determine the new inertia requirements:

- Stage 1 is using PSS®E dynamic studies to determine the critical contingencies and the impact of voltage sensitivity phenomenon including large scale IBR fault ride through, momentary DPV cessation, and load response.
- Stage 2 is to use a single mass model (SMM) to perform multiple simulations where the inertia is varied. This is tuned to include the impact of voltage sensitive phenomenon.

Success Criteria

The following conditions must be met for an islanded region to be considered as having sufficient inertia:

- Following a credible contingency event, the RoCoF for an islanded region in the mainland and islanded Tasmania must not be greater than 1 Hz/s measured over any 500ms period and 3 Hz/s measured over any 250 milliseconds (ms) period respectively.
- The tables below summarise the critical frequency outcomes that were measured against in the new inertia requirements study. Further information on the new FOS and definitions can be found on the AEMC website[33].

Table 10 Mainland system frequency outcomes for an island within the mainland other than during system restoration.

Condition	Containment band (Hz)	Stabilisation band (Hz)	Recovery band (Hz)
No contingency event or load event	49.5 – 50.5	N/A	
Generation event, load event or network event	49.0 – 51.0	49.5 – 50.5 within 5 minutes	

Table 11 Tasmania system frequency outcomes where an island is formed within Tasmania.

Condition	Containment band (Hz)	Stabilisation band (Hz)	Recovery band (Hz)
No contingency event or load event	49.0 – 51.0	N/A	
Generation event, load event or network event	48.0 – 52.0	49.0 – 51.0 within 10 minutes	

32 During a fault, IBR may cease real power production for a short period of time, and have a period of active power recovery (typically around 100-300 ms).

33 For more information about the new frequency operating standards, see the AEMC website at https://www.aemc.gov.au/news-centre/media-releases/final-determination-frequency-operating-standard#:~:text=The%20revised%20FOS%20will%20come,which%20provide%20fast%20frequency%20response.

- Following a contingency, the islanded region must be able to find a new stable operating point. This includes:
  - Voltages in the high voltage transmission network returned to nominal voltages.
  - No automatic load (underfrequency load shedding (UFLS)) or generation shedding (over frequency generation shedding (OFGS)) occurred.
  - All in-service generation remain connected and returned to new steady-state conditions, except generators that are part of the contingency considered or included in any special control or protection scheme.

Stage 1: PSS®E Dynamic Studies

The critical contingencies considered in the PSS®E dynamic studies include the loss of a generating unit, system or load that results in the highest RoCoF in the inertia sub-network. The loss of a generating unit or system can be the result of a fault on a network element and the subsequent disconnection of generation.

An important change in the methodology of this new inertia requirements study is the inclusion of AEMO's updated DPV and composite load models[34] to accurately represent load and DPV behaviours during power system disturbances.

AEMO's historical approach to load modelling is to use a ZIP load model, which is a polynomial static load model with real (Np) and reactive power (Nq) voltage indexes of 1.0 and 3.0 respectively. Recently, AEMO has developed a composite load model (CMLD) which incorporates both static and dynamic load model components. The CMLD provides a more accurate representation of voltage and frequency responses of different types of load and its tripping behaviour.

DPV was not modelled in previous annual inertia studies. When the effects of a DPV trip were to be tested, it was represented by a step increase in metropolitan loads. The new model captures the voltage, frequency, and RoCoF response of DPV, providing an accurate representation of DPV momentary cessation and DPV tripping behaviour.

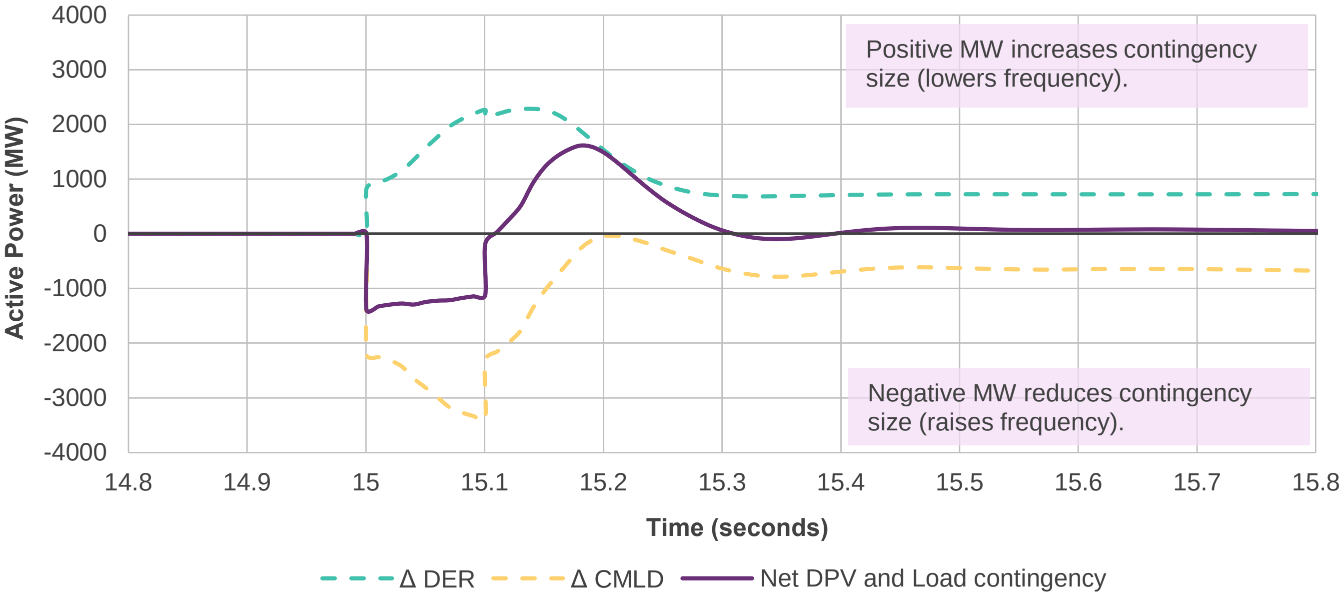
Preliminary studies have shown that the accurate modelling of such load and DPV behaviours can have significant impacts on frequency outcomes. The study results of a Queensland islanded case are included below to illustrate the significance of these behaviours. In this example study, the contingency applied is a two phase-to-ground fault at the 275 kilovolts (kV) end of Tarong North Power Station generator transformer at 15.0 seconds for 100 ms, followed by a trip of the transformer and Tarong North generator which was operating at 180 MW.

Figure 9 below shows the impact of DPV, load, and a combination of both on the contingency size. After fault clearance, the slower recovery[35] of DPV compared to load resulted in an increase in contingency size by approximately 1,500 MW.

[34] AEMO. PSS®E models for load and distributed PV in the NEM. November 2022. At https://aemo.com.au/-/media/files/initiatives/der/2022/psse-models-for-load-and-distributed-pv-in-the-nem.pdf?la=en.

[35] The distributed energy resources (DER) model parameters continuously evolve with the installation of new inverters into the NEM. The parameters used are representative of the study snapshots. In addition, AEMO is undertaking further work to better understand and improve the representation of the transient behaviour of DER and loads.

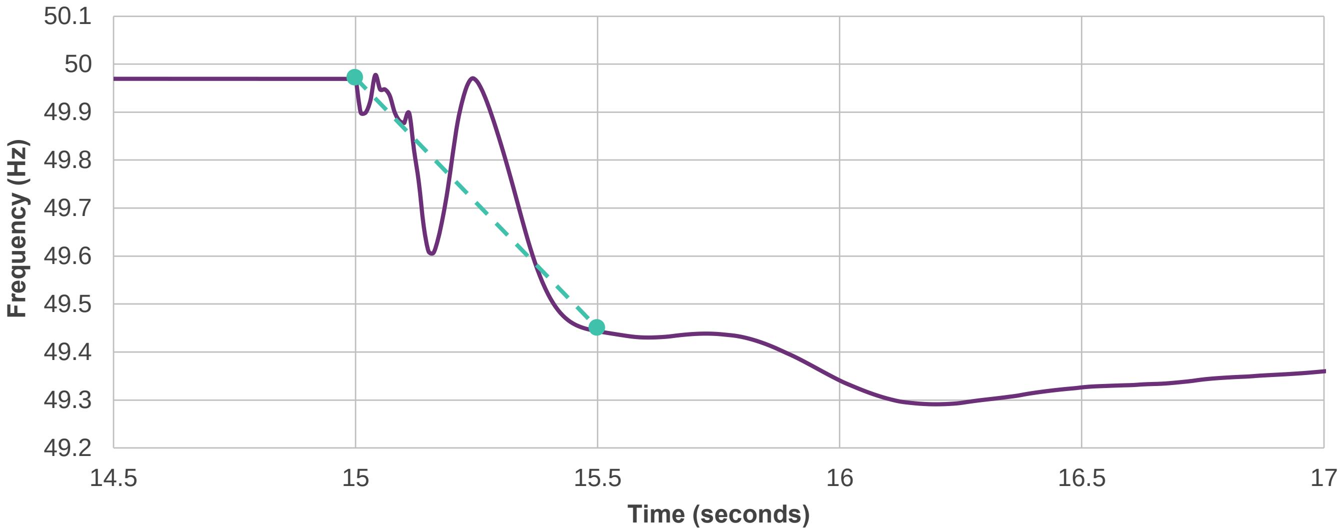
Figure 9 Net load and distributed PV response to Tarong North 180 MW contingency in an islanded Queensland



In Stage 1 studies, FFR is assumed to be wholly provided by existing batteries in the network and their response is modelled on their provided PSS®E models. When additional FFR capability was to be modelled, committed or anticipated battery energy storage system (BESS) projects were used.

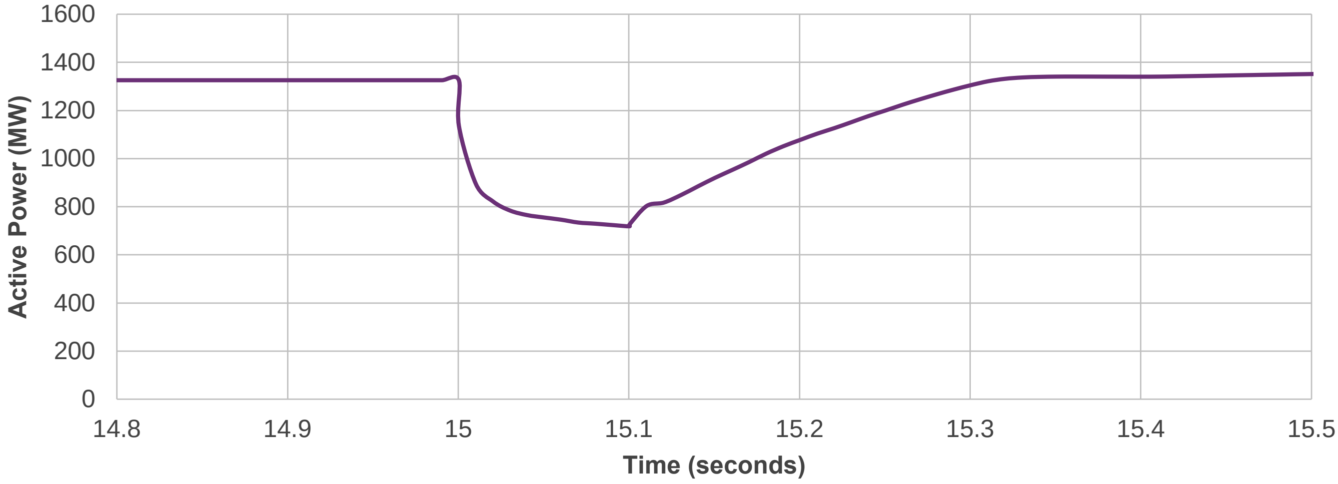
Furthermore, the new FOS specifies a RoCoF limit of 1 Hz/s measured over any 500 ms period for an islanded condition in the NEM mainland, and 3 Hz/s measured over any 250 ms period for Tasmania. The RoCoF is measured by averaging the frequency at all buses with voltage greater than or equal to 275 kV, and short-term transients are disregarded. This can be seen in Figure 10.

Figure 10 Rate of change of frequency measurement over 500 ms period



The installed capacities of large scale IBR have increased over recent years. During faults, these IBR may enter fault ride-through mode which involves reducing active power output to inject reactive power for voltage support. The fault ride-through characteristics of large scale IBR will impact frequency outcomes as the reduction in generation can be significant. Figure 11 shows the total solar farm generation in the above Queensland study. The total solar farm active power output reduced by approximately 46%, which equates to 607 MW.

Figure 11 Total solar farm generation in a Queensland islanded case under the Tarong North contingency



Stage 2: Single Mass Model

The SMM represents multiple generating units with various inertia as a single generating unit with equivalent inertia, and effectively solves the energy balance of the power system over time given the relationship between real power, frequency and inertia. The SMM is based on the swing equation of the power system and iteratively solves a set of equations for frequency to model the behaviour of the system. In Stage 1, the IBR fault ride-through, load response, and DPV response to a given contingency under a particular NEM island condition are derived from the PSS®E dynamic studies.

Given that the SMM does not model concepts such as network topology or voltage, the output data from the PSS®E studies in Stage 1 are used to modify the SMM to account for load, DPV and IBR responses to contingencies. The correct functioning of these responses, as well as all success criteria listed above, need to be checked during the PSS®E dynamic studies to ensure that the SMM can provide accurate frequency results. When solving the SMM in Stage 2, these responses are represented as additional contingencies with regards to the swing equation. The output data from Stage 1 is used to tune the SMM representation to ensure that the energy delivered across the first 500 ms after the fault is equal across PSS®E and SMM. As these responses are considered to be additional contingencies in the SMM, a positive MW change indicates a loss of MW generation or an increase in contingency size. The red curves in the figures below show examples of how the IBR fault ride-through, DPV, and load responses are simplified into linear representations and modelled in the SMM.

Figure 12 Example inverter-based resources fault ride-through representation in Single Mass Model

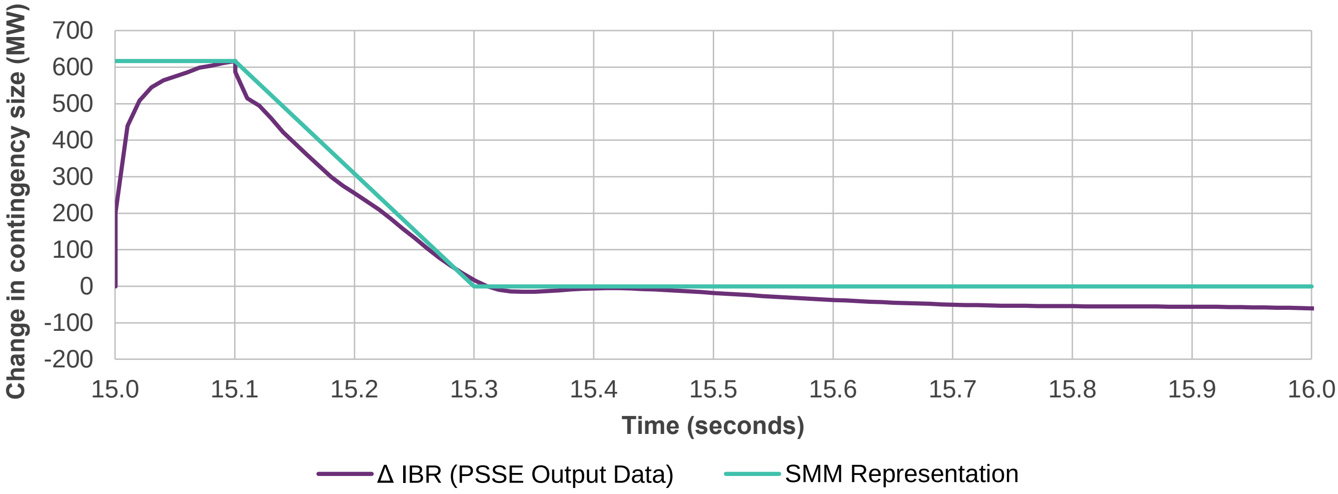


Figure 13 Example distributed PV momentary cessation and trip representation in Single Mass Model

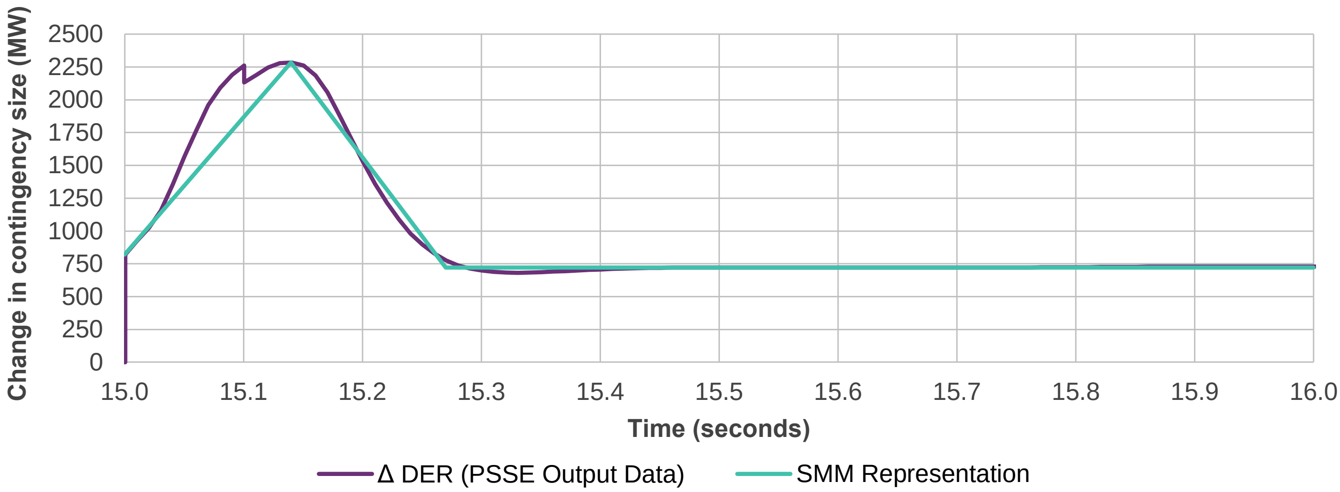
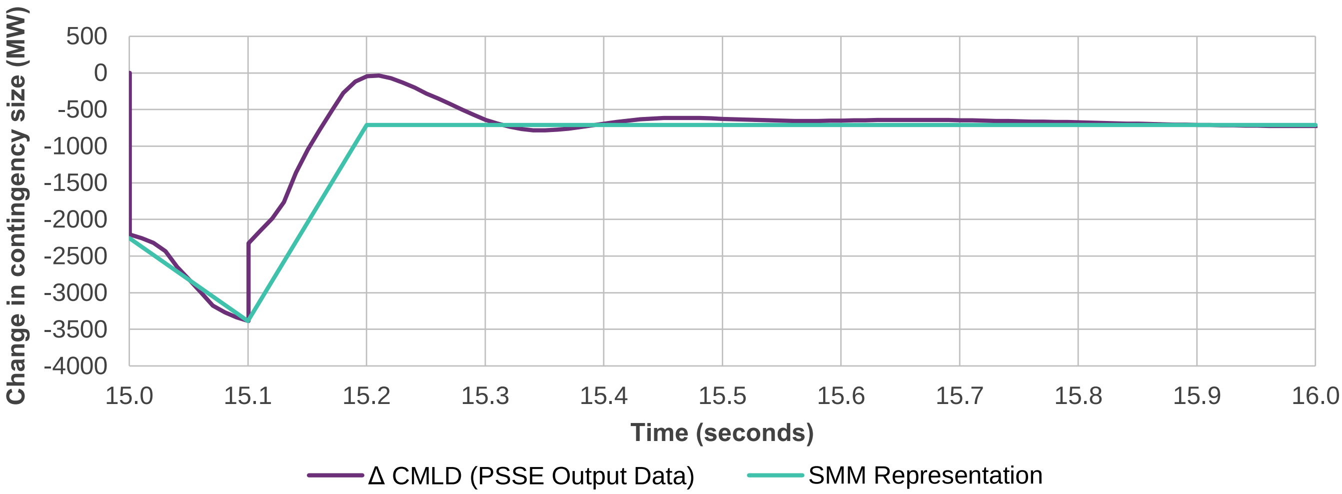


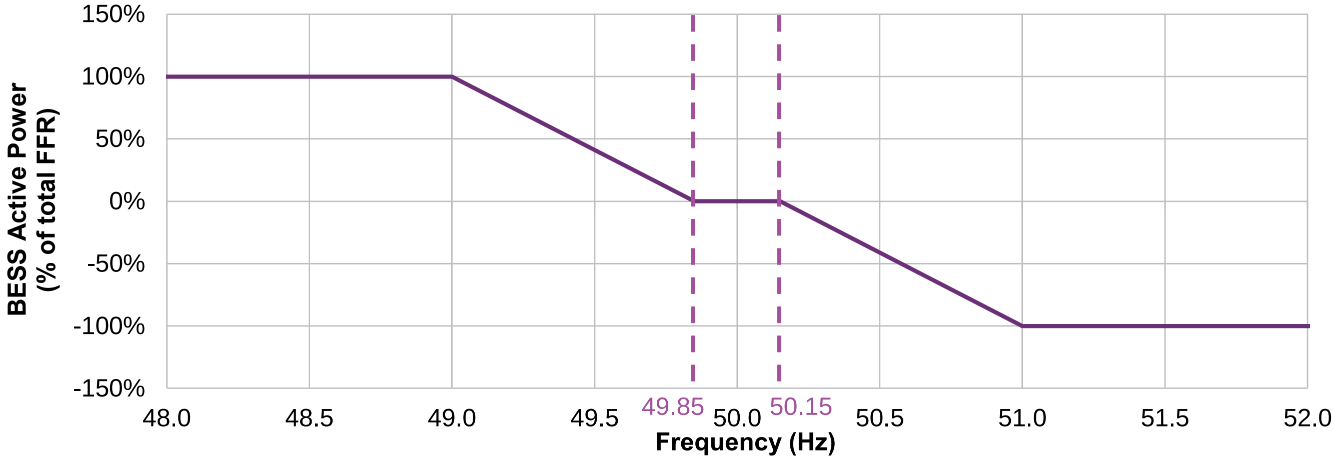
Figure 14 Example load undervoltage response and trip representation in Single Mass Model



The SMM is tuned by first calculating the areas under the SMM linear graphs and the PSS®E output data for the first 500 ms after the fault. The MW values used in the SMM representation, except for the trip amounts, are then scaled by the ratio PSS®E area : SMM area until the SMM area matches the PSS®E area.

In the SMM, the BESS provides a frequency-active power droop[36] response, as shown in Figure 15 below. As frequency drops from 49.85 Hz to 49.0 Hz, the BESS active power output increases linearly from 0% to 100% of total FFR. Similarly, as frequency increases from 50.15 Hz to 51.0 Hz, the BESS active power output drops linearly from 0% to -100% of total FFR.

Figure 15 Single Mass Model default battery energy storage system droop response in an islanded mainland region



A1.4 Defining inertia requirements as a function of fast frequency response

The secure operating level of inertia for a region is sensitive to the FFR capability available. AEMO does not model FFR as providing inertia explicitly, and instead accounts for FFR through adjustments to the inertia requirements themselves.

The relationship between inertia and FFR is typically non-linear and unique to the system conditions in each region. This reflects a spectrum of service response times – acknowledging that inertia is uniquely effective at instantaneous frequency control, while FFR is able to respond substantially within the first few hundred milliseconds.

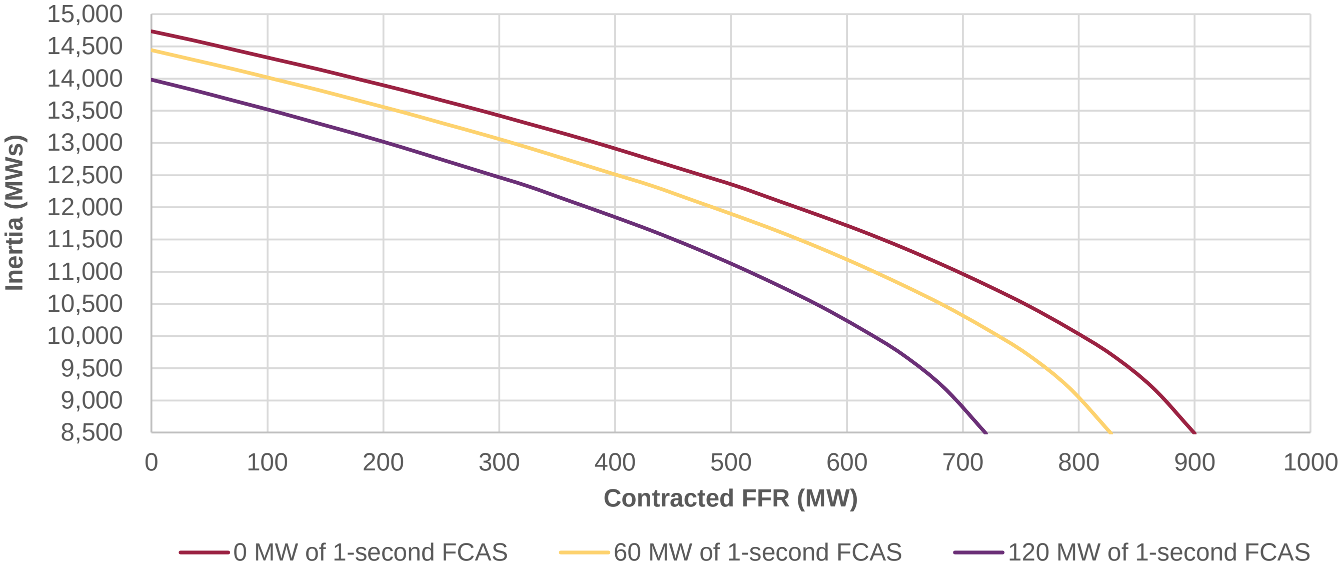
For example the relationship between inertia and FFR capability for Queensland is presented in Figure 16, where the curve defines a set of operating points that would deliver a secure level of frequency control, sufficient to meet RoCoF requirements for all credible contingency events in the region. Note, to validate the requirement, PSS®E is used to check against the other success criteria such as voltage.

The curve divides the space into acceptable and unacceptable regions and provides an opportunity for flexible solutions in addressing any declared shortfalls. For example, a projected operating point that falls below the curve (shortfall), could be returned to the curve (remediated) by moving it up (procuring inertia), or right (procuring FFR),

[36] This droop response reflects the physical response of BESS with frequency droop controllers. This response is typically faster than the response which is represented by ideal triangles in the FCAS markets. In addition, these plants typically have greater MW capability than its registered R1 and L1 capabilities.

or both up and right (procuring both inertia and FFR). The optimal mixture of remediation services will depend on both the size and timing of the shortfall.

Figure 16 Relationship between inertia and fast frequency response in Queensland



A1.4.1 How the FFR capability translates to the 1-second FCAS market

For this year, services provided by 1-second FCAS markets have been included in the modelling, however it is important to understand that for BESS providing 1-second FCAS, there is a definitional distinction between their total FFR capability, and the MW capacity registered in the 1-second FCAS market:

- FFR capability represents the total physical response available from the plant due to its nameplate capacity and control systems, typically a frequency droop controller.
- In contrast, registered 1-second FCAS capacity is based on the *peak active power* in response to a 0.5 Hz change in frequency, which is almost always less than the maximum FFR capability of a BESS.

Peak active power is a term defined in the market ancillary service specification, being the change in power due to its droop setting at the lower or raise reference frequency[37]. For a typical droop setting of 1.7%, this works out as a 1-second FCAS capacity of about 57% of FFR capability[38].

Essentially, if the frequency continues to fall below 49.5 Hz, the battery will continue to increase its output until it reaches the limit set by its droop characteristic, typically at or above 49 Hz.

Because of this difference, this document has defined the inertia requirements in terms of FFR capability, rather than 1-second FCAS capacity. There needs to be a translation between the two to accurately account for how much FFR capability results from the 1-second FCAS registration. This translation will continue to be evaluated as the 1-second FCAS market behaviour becomes more understood, including how much headroom can be expected from 1-second FCAS providers, and any change to droop settings.

[37] Lower reference frequency and raise reference frequency are 50.5 Hz and 49.5 Hz respectively (for NEM mainland).

[38] For more info, see Battery Energy Storage System guide to Contingency FCAS – Version 8, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf

Note, this translation between 1-second FCAS capacity and contracted FFR capability does not apply to switched controllers, as these do not implement a droop control response. Switched controllers must switch all the load off before frequency reaches 49.5 Hz, and do not increase response further as frequency falls further towards 49 Hz, so the translation between 1-second FCAS capacity and contracted FFR capability is 1 to 1 for these technologies.

Worked example

A region with the following 1-second FCAS registrations has approximately 92 MW of FFR capability:

Station Name	Bid Type	Registered Max Cap (MW)	Controller	Calculated FFR
BESS 1	Raise1sec	40	Droop (1.7%)	40/0.57 = 70
Switched Load A	Raise1sec	10	Switched	10
Switched Load B	Raise1sec	12	Switched	12
			Total FFR	**92**

A1.5 Likelihood of combined regions islanding

In addition to its usual consideration of the likelihood of inertia sub-networks islanding individually, AEMO has conducted additional inertia assessments of cases where two or more inertia sub-networks are at risk of forming a combined island. These assessments were performed for a New South Wales (excluding south-western New South Wales) and Queensland island, and a South Australia and Victoria (including south-western New South Wales) island (Tasmania is excluded as it provides no inertial support to Victoria).

In assessing the groupings of NEM regions that presented the highest likelihood of islanding together, AEMO considered that the greatest risk is presented for the transmission network lines connecting the Snowy area to south-western New South Wales and Victoria. The power system has been separated at this flow path on two previous occasions – in January 2007 and January 2020 – resulting in synchronous separation between the New South Wales region and the Victoria region[39].

AEMO considers it prudent for Inertia Service Providers[40] to plan for their region islanding through a range of different possible network conditions. This could include completely islanding with part or all of their adjacent region(s), or islanding with only part of their own region.

A1.6 Inertia shortfalls

When assessing an inertia shortfall, AEMO compares the levels of inertia typically available in each region of the NEM against that region's inertia requirements. Consistent with the 2022 *Inertia Report*, AEMO has assessed shortfalls based on the 99th percentile results of the selected market modelling projection, rather than results one standard deviation from the mean as outlined in the 2018 Inertia Requirements Methodology. Given the spread of

[39] Non-credible contingency events resulting in the separation of Victoria from New South Wales have been previously analysed in the 2018 Power System Frequency Risk Review (PSFRR) and more recently in the 2020 Stage 1 PSFRR. The 2022 PSFRR was published in July 2022 and considers the contingency of Loss of the Victoria – New South Wales Interconnector (VNI). AEMO's PSFRR documents are at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/general-power-system-risk-review/power-system-frequency-risk-review.

[40] As defined in NER 5.20B.4(a).

market dispatch and results, AEMO considers the 99th percentile is a more appropriate threshold to meet the NER requirements for declaring shortfalls against typical patterns of dispatched generation.

Shortfall declarations in this report are made for the five-year period from December 2023 to December 2028. However, the inertia projections presented in this report are based on market modelling using financial years, so inertia projection data is presented for 2023-24 to 2028-29.

When considering the potential for inertia shortfalls in the event of combined islands (New South Wales and Queensland, and Victoria and South Australia), AEMO compared the combined inertia level projection across the two sub-networks against the secure operating level and minimum threshold level of inertia of the sub-network with the largest credible contingency size.

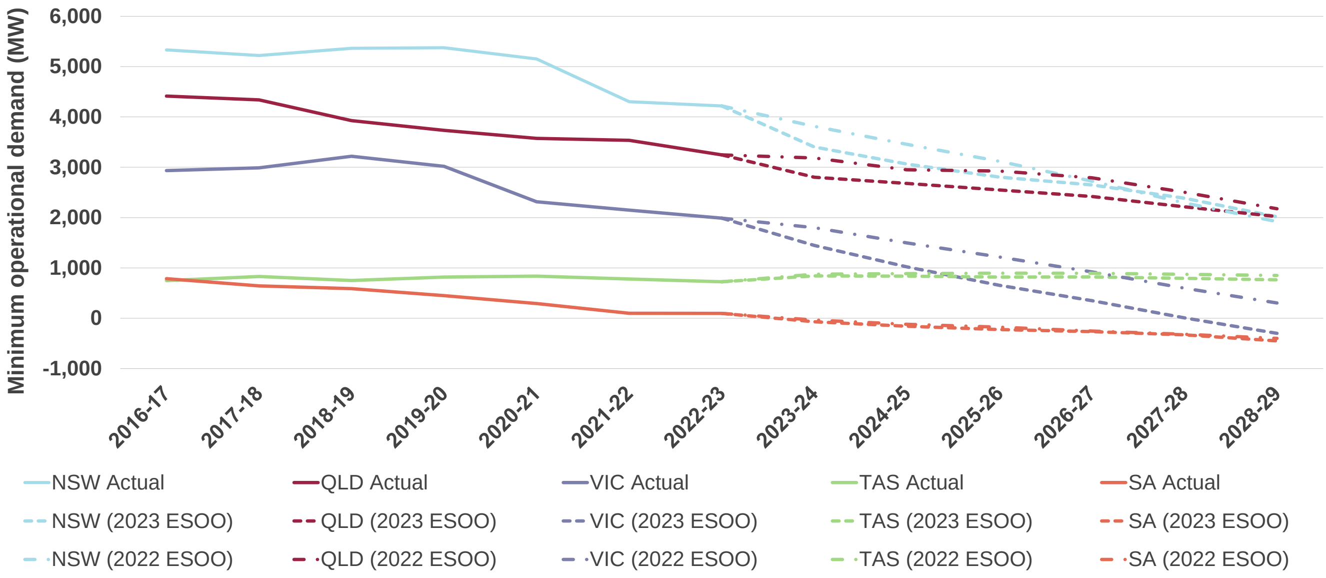
A2. Generator, network and market modelling assumptions

A2.1 Demand outlook

The inertia assessments have been prepared using the latest 2023 *Electricity Statement of Opportunities* (ESOO) Central scenario 50% probability of exceedance (POE) minimum demand projections[41].

The 2023 ESOO projects declining minimum demand values for many regions of the NEM. However, the 2023 Central scenario has a higher underlying demand across many regions compared with the previous year's forecast. Figure 17 below shows the differences in the minimum demand projections used in the 2022 and 2023 inertia assessments.

Figure 17 Minimum demand projections used in 2022 and 2023 inertia reviews



A2.2 Generator assumptions

Committed and anticipated generation projects

The inertia forecasts provided in this report consider existing generators already in service as well as any committed and committed* scheduled and semi scheduled generation projects. These projections for 2023-24 to 2028-29 incorporate projects from the September 2023 NEM Generation Information[42].

[41] AEMO National Electricity and Gas Forecasting portal at http://forecasting.aemo.com.au/Electricity/MinimumDemand/Operational.

[42] AEMO. September 2023 NEM Generation Information is available under the Archive section of AEMO's Generation information webpage, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information. Criteria for committed and committed* and anticipated are explained in the Background Information tab of the spreadsheet.

The inertia forecasts also consider anticipated projects captured in the September 2023 NEM Generation Information consistent with the references in the paragraph above, as well as any new generation forecast to be built under the market modelling results for the *Step Change* scenario prepared for the Draft 2024 ISP[43,44].

Appendix A2.4 has more details about how projects have been incorporated in the market modelling results used in this report.

Generation withdrawal and operation

The inertia forecasts in this report are aligned with the generator withdrawals and operation in the *Step Change* scenario of the Draft 2024 ISP[42].

A2.3 Transmission network augmentations

Table 12 provides the details and modelling date for the large committed, anticipated and actionable ISP transmission network augmentation projects included in the inertia forecasts in this report. These projects were not included in the assessment of the minimum threshold levels of inertia or the secure operating levels of inertia. These projects are modelled consistent with the latest information provided by TNSPs, where timing permitted.

Table 12 Large transmission network upgrades included in each assessment

	Augmentation detail	Project Status	Modelling date (Calendar year)
Project EnergyConnect	**Stage 1:** • A new Robertstown to Bundey 275 kV double circuit line. • A new Bundey to Buronga 330 kV double circuit line with one circuit connected initially. • A new 330/275 kV substation and 3x400 megavolt amperes (MVA) 275/330 kV transformers at Bundey. • A new 330/220 kV substation, 1x200 MVA 330/220 kV transformer and 1x200 MVA 330 kV phase shifting transformer at Buronga. • 1x60 MVAr 330 kV line reactor at Bundey. • 1x60 MVAr 330 kV bus connected reactor at Bundey. • 1x100 MVAr 275 kV bus connected capacitor at Bundey. • 1x50 MVAr 330 kV line reactor at Buronga. • 2x52 MVAr 330 kV capacitors at Buronga. • 1x100 MVA 330 kV connected synchronous condenser at Buronga. • An inter-trip protection scheme to trip the Project EnergyConnect interconnector if South Australia becomes separated from Victoria via the Heywood Interconnector. **Stage 2:** • Second 330 kV circuit closed on the Bundey–Buronga 330 kV double circuit line (including 1 x 60 MVAr line reactor at Bundey and 1 x 50 MVAr line reactor at Buronga of each circuit). • A new Buronga to Red Cliffs 220 kV double circuit line. • A new 330 kV double-circuit line from Dinawan to Buronga (including 50 MVAr line reactors at both ends of each circuit). • A new 500 kV double-circuit line from Dinawan to Wagga Wagga operating at 330 kV (including 50 MVAr line reactors at the Dinawan end on each circuit). • A new 330 kV switching station at Dinawan.	Committed	Stage 1 2024 [A] Stage 2 2025 [B]

[43] Final revisions ahead of publishing the Draft 2024 ISP in may result in minor changes compared with the modelling inputs used in this report.

[44] Aligned with the Draft 2024 ISP modelling assumptions, additional generation projects are included where policy frameworks include them.

	Augmentation detail	Project Status	Modelling date (Calendar year)
	• Additional 4x200 MVA 330 kV phase shifting transformers at Buronga. • Additional 2x200 MVA 330/220 kV transformers at Buronga. • An additional 1x100 MVA 330 kV connected synchronous condenser at Buronga. • New 2x100 MVA 330 kV connected synchronous condenser at Dinawan. • New 2x52 MVAr 330 kV capacitor banks at Dinawan. • Turning the existing 275 kV line between Para and Robertstown into Tungkillo. • A special protection scheme to detect and manage the loss of either of the AC interconnectors connecting to South Australia.		
Waratah Super Battery project D	• Uprate of Bannaby – Sydney West 330 kV transmission lines. • Substation works at Bannaby, Sydney West, Newcastle, Tomago, Liddell, Muswellbrook, Tamworth, Armidale, Dumaresq and Sapphire substations. • Link tendered paired generation to Waratah Super Battery with Special Integrity Protection Scheme (SIPS) control scheme. • SIPS control delivered by Transgrid. • Uprate of Yass – Collector, Collector – Marulan and Yass – Marulan 330 kV transmission lines. • Substation works at Upper Tumut, Lower Tumut, Yass, Collector, Marulan and Macarthur substations.	Committed	2025
Mortlake Turn-in	• Installing four new 500 kV circuit breakers and associated equipment to fully populate one the existing 500 kV bays and establish a new additional 500 kV bay at Mortlake Power Station. • Connecting the existing Haunted Gully to Tarrone 500 kV circuit, of the Moorabool – Heywood 500 kV double circuit line, into Mortlake Terminal Station to establish a Haunted Gully – Mortlake 500 kV circuit and a Mortlake to Tarrone 500 kV circuit.	Anticipated	2025
Victorian REZ Development Plan – Western REZ project	A 250 MVA synchronous condenser next to the Ararat Terminal Station.	Anticipated	2025
Koorangie Energy Storage System (KESS)	• Establishing a new 220 kV terminal station, located approximately 15 km north-west of the existing Kerang Terminal Station, connecting into the existing Kerang – Wemen 220 kV line. • A 185 MW big battery and grid forming inverter technology near Kerang to provide system strength services.	Anticipated	2025
Western Renewables Link	• A new 500 kV double circuit transmission line from Sydenham Terminal Station to Bulgana Terminal Station with switched shunt line reactors at the end of each circuit (approximately 70 MVAr). • Extension of the 500 kV Sydenham Terminal Station by two breaker and a half switched bays. • Additional 100 MVAr at 500 kV switched bus reactor at Sydenham Terminal Station. • Rerouting of the existing No. 1 Sydenham to South Morang and Sydenham to Keilor 500 kV transmission lines to terminate into new bays. • Construction of new 220 kV circuit breakers and a second 220 kV bus at Bulgana Terminal Station. • A new 500 kV switchyard at Bulgana Terminal Station with two new 500/220 kV 1,000 MVA transformers, transmission line realignment, site provisioning and line cut in works for the existing Bulgana to Horsham 220 kV transmission line and Crowlands to Bulgana 220kV transmission line. • Cut-in, termination and switching of the existing Ballarat to Moorabool No.2 220 kV transmission line at Elaine Terminal Station, forming Ballarat to Elaine No.2 line and Elaine to Moorabool No.2 line. • Re-alignment and switching of the existing Ballarat to Elaine transmission line and Elaine to Moorabool transmission lines at Elaine Terminal Station and renaming them to Ballarat to Elaine No.3 line and Elaine to Moorabool No.3 line. • Implement new Special Control Schemes and/or amend some existing ones at multiple stations.	Anticipated	2027

	Augmentation detail	Project Status	Modelling date (Calendar year)
	• Validation of the capabilities of the existing earthing systems at multiple stations and the connected 220 kV transmission lines optic ground wire and/or earth wire.		
Central-West Orana REZ Transmission Link [C]	The Central West Orana REZ link includes extension of the 500 kV and 330 kV network in the Central-West Orana region of New South Wales. This REZ will also include some system strength remediation as part of the build.	Anticipated	2027
HumeLink	A 500 kV transmission upgrade connecting Project EnergyConnect and the Snowy Mountains Hydroelectric Scheme to Bannaby.	Actionable ISP	2027
New England REZ	The New England REZ augmentations include additional 330 kV and 500 kV transmission network cutting in between Armidale and Tamworth, connecting renewable generation to Sydney.	Actionable NSW	2028
Sydney Ring Northern Loop	New 500 kV loop: • A new 500 kV substation near Eraring. • A new 500 kV double circuit line between substation near Eraring and Bayswater substation. Two 500/330 kV 1,500 MVA transformers either at Eraring substation or new substation near Eraring.	Actionable NSW	2028

A. Consistent with the ISP this timing is when full capacity is expected to be available following commissioning and interconnector testing. However, construction and first energisation is expected in the second half of 2023, with commissioning activities and inter-network testing scheduled to follow first energisation. Network for PEC Stage 1 (including one synchronous condenser) is modelled from in-service date in December 2023.
B. Consistent with the ISP this timing is when full capacity is expected to be available following commissioning and interconnector testing. However, construction and first energisation is expected in the second half of 2024, with commissioning activities and inter-network testing scheduled to follow first energisation. It is expected that Project EnergyConnect will progressively release transfer capacity from July 2024 onwards.
C. EnergyCo will build system strength remediation in some form for the CWO REZ. AEMO has included latest information on this remediation.
D. As per NSW Government's announcement, at https://www.energyco.nsw.gov.au/waratah-super-battery-munmorah-site.

A2.4 Market modelling of generator dispatch method

AEMO undertakes integrated energy market modelling to forecast future investment in and operation of electricity generation, storage and transmission in the NEM[45].

Projected generation and storage investment and dispatch from the *Step Change* scenario results for the early results in the Draft 2024 ISP have been used for inertia forecasts in this report, with some updates to reflect the latest information. These market modelling results:

- Cover the financial years from 2023-24 to 2028-29.
- Are based on the *Step Change* scenario generator, storage and transmission build outcomes for the Draft 2024 ISP[46].
- Include generator dispatch projections from a time-sequential model using the 'bidding behaviour model' for realistic generator dispatch results given the generation and build outcomes. The bidding behaviour model uses historical analysis of actual generator bidding data and back-cast approaches for the purposes of calibrating projected dispatch[47].
- Apply the *Step Change* scenario 50% POE demand projection from the 2023 ESOO.

[45] Information about AEMO's energy market modelling can be found in the July 2020 Market Modelling Methodologies report as well as the 2021 ISP Methodology, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en and https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/isp-methodology respectively.

[46] Final revisions ahead of publishing the Draft 2024 ISP in may result in minor changes compared with the modelling inputs used in this report.

[47] Details for the bidding behaviour model are provided in AEMO's Market Modelling Methodologies report. AEMO, Market Modelling Methodologies, July 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptionsmethodologies/2020/market-modelling-methodology-paper-jul-20.pdf?la=en.

- Apply projections of generation outages based on Monte Carlo simulation.
- Apply projections of planned maintenance. Maintenance events are assumed to be distributed throughout the year such that they minimise planned outages at times when it is most required when consumer demand is high, to avoid exacerbating reliability risks.
- Incorporate a range of market modelling iterations for each year of the study period, capturing multiple generator outage patterns. This better captures the variability in generator outage patterns, and hence gives better regard of typical dispatch patterns.

When applying the market modelling results to assess the inertia projections, some post model adjustments were made where necessary based on industry knowledge and known operational practices.