Inertia Requirements Methodology

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Note: There is a full version history at the end of this document.

1. Introduction

1.1. Purpose and scope

This is the *Inertia Requirements Methodology (Methodology)* made under clause 5.20.4 of the National Electricity Rules (NER).

This Methodology has effect only for the purposes set out in the NER. The NER and the *National Electricity Law* (NEL) prevail over this Methodology to the extent of any inconsistency.

This Methodology provides the process AEMO uses to determine the *inertia requirements* for each *region* of the National Electricity Market (NEM). This includes:

- Description of the modelling and analysis methodologies AEMO will use to determine the *system-wide inertia level*.
- Overview of *inertia sub-networks* and the process to declare them.
- Description of the methodology AEMO will use to allocate the *system-wide inertia level* to each *inertia sub-network*.
- Description of the modelling and analysis methodologies AEMO will use to determine the *satisfactory inertia level* for *each inertia sub-network.*
- Description of the modelling and analysis methodologies AEMO will use to determine the *secure inertia level* for each *inertia sub-network.*
- Description of the methodology AEMO will use to determine the *sub-network islanding risk* for each *inertia sub-network*.
- Information on the types of *inertia support activities* that AEMO will consider if requested by an *Inertia Service Provider*.
- Description of each kind of *inertia network service*, the relevant performance parameters and requirements, and the process and requirements for AEMO to approve the equipment through an *inertia network services specification*.

1.2. Glossary and interpretation

1.2.1. Glossary

Terms defined in the *National Electricity Law* and the NER have the same meanings in this Methodology unless otherwise specified in this clause. Terms defined in the NER are intended to be identified in this Methodology by italicising them, but failure to italicise a defined term does not affect its meaning.

In addition, the words, phrases and abbreviations in the table below have the meanings set out opposite them when used in this Methodology.

Term	Definition
1s FCAS	1-second FCAS markets, also referred to very fast FCAS (VFFCAS)
AC	alternating current

Term	Definition
Acceptable Frequency	The *frequency* at all energised *busbars* of the *power system* is within the *normal operating frequency band*, except for brief excursions outside the *normal operating frequency band* which remain within the *normal operating frequency excursion band*
AEMC	Australian Energy Market Commission
Amending Rule	National Electricity Amendment (Improving security frameworks for the energy transition) Rule 2024 No. 9[1]. All rules references in the document are as per this amendment.
AVR	automatic *voltage* control
BESS	battery energy storage system/s
CMLD	composite *load* model
Contingency FCAS	Each of the following: • *Very fast raise service.* • *Very fast lower service.* • *Fast raise service.* • *Fast lower service.* • *Slow raise service.* • *Slow lower service.* • *Delayed raise service.* • *Delayed lower service.*
DC	direct current
DMAT	dynamic model acceptance test
DPV	distributed photovoltaics
EMT	electromagnetic transient
ESOO	Electricity Statement of Opportunities
Fast FCAS	*fast raise service* and *fast lower service*
FCAS	*frequency* control ancillary service/s
FFR	fast *frequency* response
FOS	frequency operating standard
FRT	fault ride-through
Generation event	Any of the following events: 1. A synchronisation of a *generating unit* of more than the *generation* event threshold of: a) for the Mainland: 50 megawatts (MW). b) for Tasmania: 20 MW. 2. An event that results in the sudden, unexpected and significant increase or decrease in the *generation* of one or more generating systems totalling more than the *generation* event threshold for the *region* in aggregate within no more than 30 seconds. 3. The *disconnection* of *generation* as the result of a *credible contingency event* (not arising from a *load* event, a *network* event, a separation event or part of a multiple *contingency event*), in respect of either a single generating system or a single dedicated *connection* asset providing *connection* to one or more generating systems.
HIL testing	Hardware-in-the-loop testing. Physical testing of a device that involves placing the device in a controlled bench test where its outputs are observed and measured.
Hz	hertz

[1] AEMC, 'Improving security frameworks for the energy transition', at https://www.aemc.gov.au/rule-changes/improving-security-frameworks-energy-transition.

Term	Definition
IBR	inverter-based resource/s
Island	A part of the *power system* that includes *generation*, *networks*, and *load*, for which all of its alternating current *network connections* with other parts of the *power system* have been disconnected.
ISP	Integrated System Plan
Load event	For the Mainland: *connection* or *disconnection* of more than 50 MW of *load* not resulting from a *network* event, *generation* event, separation event or part of a multiple *contingency event*. For Tasmania: either a change of more than 20 MW of *load*, or a rapid change of flow by a high *voltage* direct current *interconnector* to or from 0 MW to start, stop or reverse its power flow, not arising from a *network* event, *generation* event, separation event or part of a multiple *contingency event*.
Mainland	The Queensland, New South Wales, Victoria and South Australia *regions*
MASS	*Market Ancillary Service Specification*
Methodology	AEMO's Inertia Requirements Methodology
ms	millisecond/s
MW	megawatt/s
MWh	megawatt-hour/s
MWs	megawatt-second/s
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rule.
Network event	A credible *contingency event* other than a *generation* event, *load* event, separation event or part of a multiple *contingency event*
Non-synchronous equipment	Equipment that is not a synchronous production unit or a synchronous condenser
NSCAS	*network* support and control ancillary service/s
NSP	Network Service Provider
NSW	New South Wales
OEM	original equipment manufacturer
OFGS	over-*frequency generation* shedding
PSCAD™/EMTDC™	Power System Computer Aided Simulation / Electromagnetic Transient with Direct Current
PSS	*power system* stabiliser
PSS®E	Power System Simulator for Engineering
pu	per unit
RAS	remedial action scheme
RoCoF	rate of change of *frequency*
s	second/s
SA	South Australia
Separation event	A *credible contingency event* affecting a *transmission* element that results in an *island*
SMM	single mass model
SSSP	System Strength Service Provider
STATCOM	static compensator
Synchronous Machine	*Synchronous generating units* and *synchronous condensers*

Term	Definition
Synthetic inertial response	The emulated inertial response from an inverter-based resource that is inherently initiated in response to a *power system* disturbance, and sufficiently fast and large enough to help manage RoCoF
TNSP	*Transmission Network Service Provider*
UFLS	under-*frequency load shedding*

1.2.2. Interpretation

This Methodology is subject to the principles of interpretation set out in Schedule 2 of the *National Electricity Law*.

1.3. Related documents

Title	Location
System Strength Requirements Methodology	https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en
NSCAS description and quantity procedure	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2021/nscas-description-and-quantity-procedure-v2-2.pdf?la=en
Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System – Preliminary Report	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf?la=en
Voluntary Specification for Grid-forming Inverters	https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf?la=en
Voluntary Specification for Grid-forming Inverters: Core Requirements Test Framework	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf?la=en
Inertia in the NEM explained	https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en
Frequency Operating Standard	https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20%E2%80%8COperating%20Standard.pdf

1.4. Overview of Methodology

The remaining sections of this Methodology are structured as follows:

- Section 2 provides background information, including the principles that underpin the Methodology.
- Section 3 describes the NER requirements for *inertia network services* and *inertia support activities*.
- Section 4 defines the relevant methodology terminology and sets out the assessment method for calculating the *inertia requirements*.

2. Background

2.1. Inertia and related concepts

2.1.1. Inertia definition and inertia support activities

Inertia is defined in the NER[2] as:

Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, bidirectional unit, network element or other equipment.

An inertial response is the immediate, inherent, electrical power exchange from a device on the *power system* in response to a *frequency* disturbance. *Power system inertia* is the aggregate equivalent *inertia* of all devices on the *power system* capable of providing an inertial response[3].

A response is considered inherent if it is initiated by the device resisting a change to the *voltage* angle at its point of *connection* that occurs during a change in system *frequency*. The response may or may not then be shaped over a short timeframe by control system action such as primary *frequency* response, *frequency* control ancillary services (FCAS), or action to keep device output within limits.

Inertia support activities are activities approved by AEMO under the NER which adjust the *binding inertia levels*, but are not strictly *inertia network services*[4]. These are also discussed in this section as they are important in determining the *inertia requirements* under the NER[5].

2.1.2. Why inertia is important in the NEM

Historically, the NEM *power system* did not require *Registered Participants* to provide *inertia* because there was always an abundance of *synchronous generating units* online.

A decrease in the proportion of online *synchronous generation* has resulted in a reduction of the *inertia* inherently available to the *power system*.

While it has historically been common to consider *power system inertia* as a global parameter at a system level, the exchange of *active power* involving multiple inertial responses is limited by available *network* capacity for power transfer. During a disturbance, if the distribution of *power system inertia* is concentrated in an area of the *network* with insufficient capacity to carry the resultant power flows out to the rest of the system, the impacts of exceeding transfer limits and other flow-on effects must be considered. This is particularly true for large, sparse *networks* such as the NEM. Consequently, it is critical to ensure a geographically diverse distribution of *power system inertia* across the NEM.

With any loss of transfer capacity for *active power*, for example resulting from a separation event, *inertia* that is not electrically connected[6] to the alternating current (AC) *power system inertia sub-*

[2] NER Chapter 10 Glossary

[3] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/inertia-in-the-nem-explained.pdf?la=en.

[4] NER 5.20B.5(a)

[5] NER 5.20B.2

[6] As *active power* across direct current (DC) *interconnectors* is controlled, inertial responses across DC connected systems are only possible if the converters of the DC *interconnectors* are designed to provide synthetic inertial response.

network of interest has no effect on that *inertia sub-network*. This means each *inertia sub-network* in the *power system* needs to maintain a minimum level of *power system inertia* in case of total *islanding*.

2.1.3. Rate of change of frequency (RoCoF)

In a *power system*, *inertia* and *frequency* are closely related. *Power systems* with large *inertia* can resist large changes in *power system frequency* arising from a contingency that leads to an imbalance in supply and demand. Conversely, lower levels of *inertia* increase the susceptibility of the *power system* to rapid changes in frequency because of such an imbalance.

Immediately after a *contingency event* that leads to a supply-demand mismatch, *power system frequency* changes. For a very short time following a *contingency event*, the RoCoF largely depends on the *power system* conditions prior to the *contingency event*. Prior to the occurrence of a *contingency event*, the following measures can be taken to reduce post-contingent RoCoF:

(a) reduce the size of the largest *credible contingency event* by reducing *generation* output, *load* consumption or limiting *interconnector* flow for the relevant credible contingency elements;

(b) increase the *inertia*; or

(c) do both (a) and (b).

Limiting RoCoF only increases the time before frequency moves outside the normal operating *frequency band*. Table 1 shows the time required for the frequency to reach the under-frequency *load shedding* threshold for various RoCoFs.

Table 1 RoCoF and time to reach 49 hertz (Hz)

RoCoF (hertz per second (Hz/s))	Time to reach 49 Hz* (seconds)
4	0.25
2	0.5
1	1
0.5	2

* Starting from 50 Hz.

2.1.4. Frequency control market ancillary services (FCAS)

Inertia by itself cannot arrest a fall in *power system frequency* indefinitely or bring it back to be within the normal operating *frequency band*; it can only reduce the rate at which frequency changes. The *power system* needs additional measures to bring frequency back within its normal operating *frequency band*. AEMO currently uses Contingency FCAS for this purpose.

Contingency FCAS is a type of frequency control ancillary service (FCAS) that helps correct the frequency after a *contingency event*. Currently, this service is mainly provided by *synchronous generation* and batteries. *Synchronous generation* uses the speed of the turbine as a proxy for *power system frequency*. There is a close relationship between the speed of a *synchronous* machine and *power system frequency*, but the two quantities are not directly interchangeable when it comes to controls.

One-second (1s) FCAS can help reduce RoCoF, when measured over a 500 milliseconds (ms) window, due to its fast response time. However, it has limited ability to resist RoCoF in the sub transient timeframe.

2.1.5. Fast frequency response (FFR) and 1-second FCAS

This Methodology uses FFR as the term to describe the total physical capability of devices to quickly measure and respond to a frequency event. Typically, these devices are batteries. For FFR-like services to be procured, a new very fast (1s) FCAS market commenced on 9 October 2023.

For battery energy storage systems (BESS) providing 1s FCAS, there is a definitional distinction between their total FFR capability and the megawatt (MW) capacity registered in the 1s FCAS market[7]:

- 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 1s FCAS capacity is based on the peak *active power* in response to a 0.5 hertz (Hz) change in frequency, which is almost always less than the maximum FFR capability of a BESS.
- For further information on how AEMO distinguishes between FFR and 1s FCAS in this Methodology, refer to Appendix C.

FFR and 1s FCAS are typically *inertia support activities*.

2.1.6. Remedial action schemes

A fast balance between supply and demand post-contingency can also be achieved by rapidly controlling *generation* or *load*. Depending on the circumstances, this might need to occur considerably faster than any *market ancillary service* if *power system security* is to be maintained in accordance with the NER.

This can be achieved using remedial action schemes (RAS). They can be:

- 'Event-based', providing coverage for a small number of specific events (possibly even just one) via dedicated triggering mechanisms, or
- 'Measurement-based', providing coverage for a broad range of events based on observable metrics, such as *frequency*, *voltage*, or power flow.

2.1.7. Contracting for inertia support activities

Contracting with *Generators* with large *generating units* to reduce their operating levels, thereby reducing the size of the loss of *generation* following a *contingency event*, would reduce the level of *inertia* required to maintain the *power system* in a *secure operating state*. These services can be contracted as *inertia support activities*.

2.1.8. Synchronous generation

Historically, it was not necessary to consider *inertia* as a necessary service to achieve *power system security*, because there were many *synchronous* generating systems connected to the *power system*, and these provided *inertia* as a matter of course.

[7] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

Synchronous generation technologies, such as coal, gas and hydro, all operate large spinning turbines and rotors that are synchronised to the *frequency* of the *power system*. They are typically heavy, weighing in the tens and hundreds of tonnes, and naturally provide *inertia* to the *power system*.

When a sudden imbalance between supply and demand occurs, the kinetic energy stored in the rotating mass of the turbine immediately starts to flow into or out of the *power system* to fill the gap in power and restore balance. Hence, *power systems* with large numbers of online *synchronous* generating machines will have a greater ability to resist changes in *power system frequency* than those that do not.

These are devices which provide an *inertia network service*.

2.1.9. Non-synchronous equipment providing an inertial response

Non-synchronous equipment , such as modern wind turbines, solar inverters and batteries, 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 inverter-based resources (IBR) to provide a synthetic inertial response through appropriate designs and controls. This type of response can include a spectrum of services that differ in how they achieve this response.

Synthetic inertia is still an emerging area, and industry has not yet reached consensus on its definition. To aid this process, AEMO has *published* a voluntary specification for grid-forming inverters[8].

Under the framework these are tested through the *inertia network services specification* in Appendix A.

2.1.10. Synchronous condensers

Synchronous condensers are rotating machines *synchronously* connected to the *power system*, to provide services such as system strength, *voltage* control and inertia. However, they do not have the ability to *generate* or consume[9] *active power* beyond their inertial response and therefore do not provide FCAS.

These are devices which provide an *inertia network service.*

2.1.11. Loads

There is a significant amount of *inertia* from demand side and distributed energy sources present on the NEM[10]. This can come from any induction machine or other device, right down to consumer devices. AEMO acknowledges this, however this inertial contribution will be considered when comparing the amount of *inertia* in the system against the requirements, rather than including it as part of the *inertia requirements*.

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[8] AEMO. Voluntary Specification for Grid-forming Inverters, May 2023, at https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2023/gfm-voluntary-spec.pdf.

[9] Except for consuming a small constant amount of power to keep them rotating.

[10] Arena. Reactive Technologies, System Inertia Measurement Demonstration Lessons Learnt Report 2, at https://arena.gov.au/assets/2024/01/Reactive-System-Inertia-Measurement-Demonstration-Lessons-Learned-Report-2.pdf.

2.1.12. Direct current (DC) interconnection

At present no DC *interconnection* in the NEM is able to provide inertia, however this may change in the future. It will be considered if this technology is deployed in the NEM.

2.2. Relationship between inertia requirements and other documents

2.2.1. Frequency Operating Standard (FOS)

Inertia is measured by reference to AEMO's ability to operate an *inertia sub-network* in a *satisfactory operating state* or a *secure operating state* when the *inertia sub-network* is *islanded*. AEMO must also be able to operate the mainland NEM in a *secure operating state* where no *inertia sub-network* is *islanded*. These parameters depend, among other things, on AEMO's ability to maintain *power system frequency* within certain parameters[11].

Although referred to as the Frequency Operating Standard, there are, in fact, two standards: one for the mainland *region*s and one for Tasmania. The FOS[12] specifies the *frequency bands* and timeframes in which *power system frequency* must be restored following different events, but does not set out how frequency is to be managed.

A revised FOS became effective in October 2023, and now specifies a maximum RoCoF for a credible contingency event of 1 hertz per second (Hz/s) for the mainland and 3 Hz/s for Tasmania[13].

2.2.2. System strength requirements methodology, system strength requirements and network support and control ancillary services (NSCAS)

In October 2021, the Australian Energy Market Commission (AEMC) changed the previous system strength framework to drive more proactivity in the provision of system strength services, deliver a streamlined *connection* process, and leverage economies of scale in larger, centralised investments[14]. A new mechanism was also introduced to allow *connection* applicants to decide between procuring their own system strength assets or contributing towards a fleet of centrally provided services.

Each NEM *region's* jurisdictional planning body is the System Strength Service Provider (SSSP) in accordance with the NER[15]. The SSSP must plan, design, maintain and operate its *transmission network*, or make system strength services available to AEMO, to meet NER requirements including to meet the *minimum three phase fault level* and the *efficient level of system strength* in the *system strength standard specification* in accordance with NER S5.1.14[16]. The *system strength standard specification* is

[11] NER 4.2.2(a)

[12] AEMC, Frequency Operating Standard, 9 October 2023, at https://www.aemc.gov.au/sites/default/files/2024-01/Frequency%20%E2%80%8COperating%20Standard.pdf

[13] AEMC, Review of the Frequence Operating Standard 2022, at https://www.aemc.gov.au/market-reviews-advice/review-frequency-operating-standard-2022.

[14] AEMC, Efficient management of system strength of the *power system*, at https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system.

[15] NER 5.20C.3

[16] NER S5.1.14

determined by the *system strength requirements published* by AEMO under the *system strength requirements methodology*[17]. AEMO *publishes* a 10-year projection of *system strength requirements* each year.

System strength and *inertia* are related because they can both refer to different aspects of the *power system's* ability to inherently resist a change in the *voltage* waveform. Services that provide one type of service often provide some amount of the other as a byproduct, depending on the design. For example, higher *inertia synchronous* machines tend to have a higher damping factor, which is beneficial for reducing *voltage* oscillations[18] associated with low system strength. A certain amount of *inertia* will invariably be available in each *region* because of the implementation of the system strength requirements.

Under the Amending Rule, the system strength and *inertia* procurement timeframes have been aligned, to allow for co-optimised security investment. The Amending Rule includes a form of backstop procurement by AEMO in specified circumstances when AEMO declares *inertia* and system strength *shortfalls* through the NSCAS framework within a three-year period[19].

2.2.3. Power System Model Guidelines

The *Power System Model Guidelines* detail AEMO's requirements for data and models from Applicants and facilitate access to the technical information and modelling data necessary to perform the required analysis.

Submission of accurate models in an appropriate format facilitates a robust analysis of the *power system*, leading to confidence in the assessment and determination of the *inertia requirements*.

[17] AEMO, System Strength Requirements Methodology, 1 December 2022 at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-strength-requirements/system-strength-requirements-methodology.pdf?la=en.

[18] See page 30, https://www.transgrid.com.au/media/fo0maqsh/2406-transgrid_meeting-system-strength-requirements-in-nsw-padr.pdf.

[19] NER 5.20.3(c1) and 5.20.3(c2)

3. Defining inertia sub-networks and islanding risk

3.1. Inertia sub-network boundaries

NER 5.20B.1(a) requires AEMO to divide the national grid into *inertia sub-networks*.

For the purpose of determining the required levels of *inertia* in the national grid, the connected *transmission* systems forming part of the national grid are to be divided into *inertia sub-networks*. Under clause 5.20B.1(c) of the NER, the boundaries of an *inertia sub-network* must be aligned with the boundaries of a *region* or wholly confined within a *region*.

AEMO may adjust the boundaries of *inertia sub-networks* from time to time, including adjustments that result in new *inertia sub-networks*, in accordance with clause 5.20B.1(b) and the Rules consultation procedures. In making this determination, regard shall be had to the *synchronous connections* between *sub-networks* and adjacent parts of the grid, and the criticality and practicality of satisfying each *inertia sub-network's inertia requirements*.

AEMO confirms that the *inertia sub-networks* remain aligned with *regions*[20,21].

3.2. Approach for determining likelihood of inertia sub-network islanding risk

NER clause 5.20.4(d2) requires that this Methodology describe how AEMO determines the likelihood of an *inertia sub-network islanding risk*.

AEMO considers the list of factors from NER 5.20B.2(d) when determining and forecasting the likelihood of a *sub-network islanding*. The list includes matters that AEMO reasonably considers relevant in making its assessment. AEMO considers it is relevant to consider evidence from historical *islanding* events, and the frequency or likelihood of specific non-credible events being reclassified as credible in operational timeframes.

AEMO assesses all listed factors for each *inertia sub-network* as part of the annual Inertia Report. On a case by case basis, AEMO may consider additional matters it reasonably considers relevant to the assessment, and will justify these in the annual Inertia Report where applied. AEMO will classify the resulting likelihood of a *sub-network islanding risk* as either 'plausible' or 'not plausible' for the purposes of applying any calculated *sub-network inertia requirements*.

Combined islands

There may be *regions* that are unlikely to *island* individually, due to the number and strength of *connections* they have with adjacent *regions*, but are at risk of forming a combined *island*. As such, in addition to its usual consideration of the likelihood of *inertia sub-networks islanding* individually, AEMO

[20] A region in the NEM is an area determined by the Australian Energy Market Commission (AEMC) as being an area served by a particular part of the transmission network containing one or more major load centres or generation centres or both. The current regions in the NEM are largely based on Australian jurisdictional boundaries - New South Wales, Queensland, Tasmania, Victoria and South Australia."

[21] NER 11.100.2

conducts additional *inertia* assessments of cases where two or more *inertia sub-networks* are at risk of forming a combined *island*.

AEMO undertakes a consistent assessment methodology for determining any multi-region *islanding* risks as for the individual *sub-network islanding risks*. For a combined *island*, the *inertia requirement* for the combined *island* will be the highest *binding inertia requirement* for each individual *inertia sub-network*.

Example assessments

Table 2 shows an example of how AEMO presents the results of its *inertia sub-network islanding risk* determination in the Inertia Report. This table is presented as an example only and does not contain comprehensive or accurate assessment of the *regions*.

Table 2 Inertia sub-network islanding risk criteria with New South Wales and South Australia examples

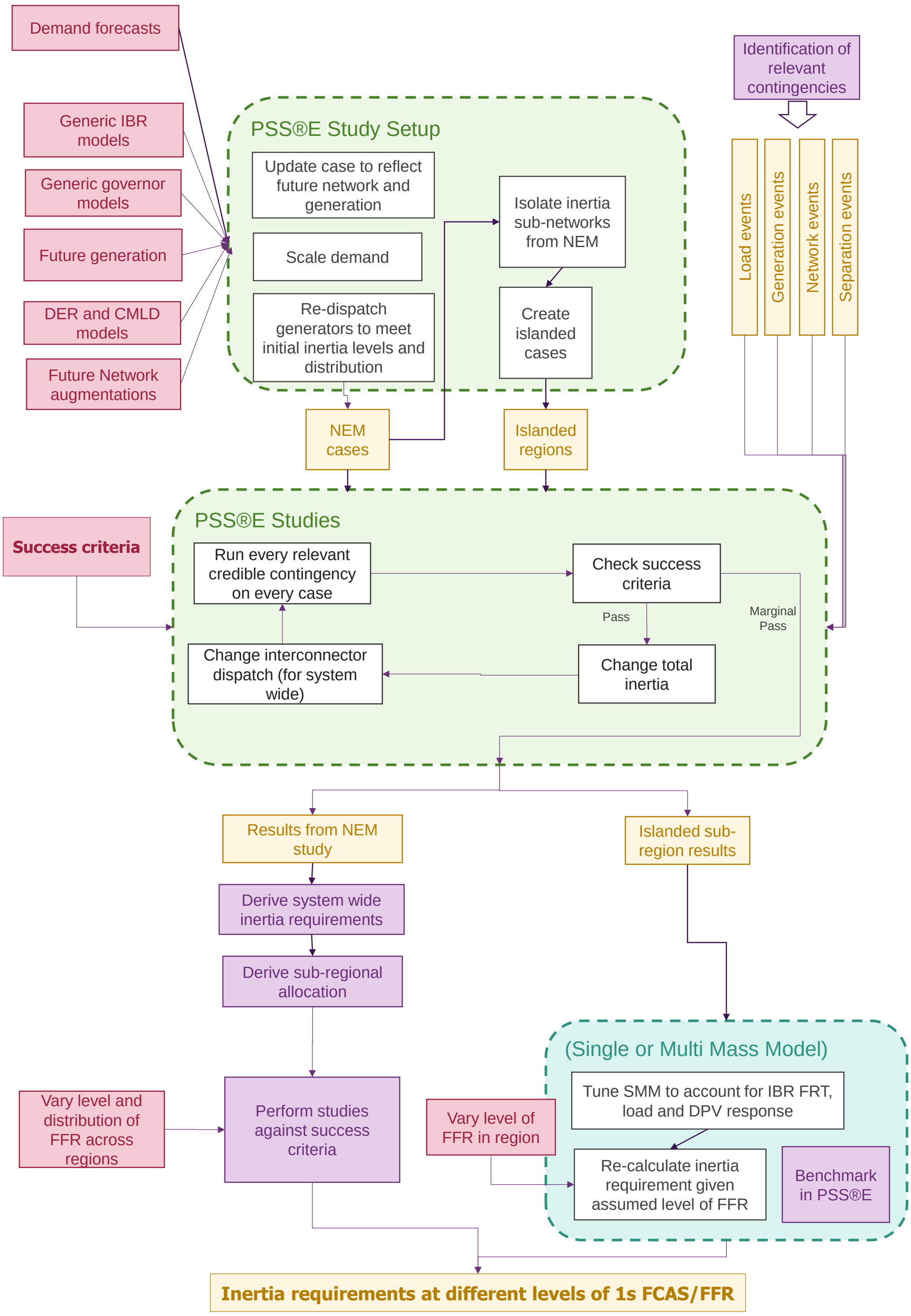
Criterion	New South Wales	South Australia	...
Inertia levels typically provided	22,295 MWs	4,400 MWs	...
Inertia levels compared to secure inertia level	*Inertia* levels forecast to be above the *secure inertia level* at all times until FY2029.	*Inertia* levels forecast to be 2,300 MWs below the *secure inertia level* 24% of the time in FY2025, which may increase to approximately 53% of the time by FY2029.	
Inertia sub-network allocation (example)	9,000 MWs	1,000 MWs	
Existing interconnections	• One 220 kV and three 330 kV AC *connections* to Victoria. • One 330 kV AC double-circuit and one DC link *connection* to Queensland.	• One 275 kV AC double-circuit to Victoria. • One DC link to Victoria. •	
Future interconnections and status	• PEC: 330 kV double-circuit to South Australia and 220 kV double-circuit to Victoria (Stage 1: 2024, Stage 2: 2027). • VNI West: 500 kV double-circuit to Victoria (2029). • QNI Connect: 330 kV double circuit to Queensland (2033).	• PEC: 330 kV double-circuit to New South Wales (Stage 1: 2024, Stage 2: 2027).	
History of islanding	N/A	• November 2022 • March 2020 • January 2020 • November 2019 • August 2018 • December 2016 • September 2016 • November 2015	
Applicable control schemes	TBC	TBC	
Likelihood of islanding after contingency event	Not likely	Plausible until PEC is commissioned	

MWs: megawatt-second/s.

4. Determining inertia requirements

AEMO will determine the *system-wide inertia level*, *satisfactory inertia level* and *secure inertia level* using the approach in this section, to comply with NER clauses 5.20B.2(b)(1), 5.20B.2(b)(3), and 5.20B.2(b)(4). An overview of the approach is provided in Figure 1, followed by detailed descriptions of the various stages.

Figure 1 Overview of approach to determining inertia requirements



4.1. Setting key assumptions, inputs and information

Power system models

The *power system* model is based on a NEM *load* flow case with dynamic information[22]. This is then updated with changes considered significant and relevant within the next 10 years when calculating the *inertia requirements*, which can include:

- Committed and anticipated *generation*, and *generator* retirement.
- Future *network* development.
- Demand forecasts.
- Latest Composite Load Model (CMLD) and distributed photovoltaics (DPV) models as developed by AEMO[23].

Where needed, this can draw on the Integrated System Plan (ISP) and the NEM Electricity Statement of Opportunities (ESOO). AEMO will utilise appropriate generic dynamic models where specific information is not available. This includes in-house generic governor models for *synchronous* machines and best available generic models for IBR, such as the REGC_*[24].

All BESS are assumed to be online and *dispatching* in the initial case. This assumption will be varied in section 4.7, to ensure the provision of FFR from BESS is reflected in the requirements. Actual models will be used where available, however appropriate generic models will be used if needed.

AEMO will update the PSS®E to case to include these updates. AEMO will develop *islanded* sub *network* cases by taking *interconnectors* out of service and *re-dispatching generation* within the *region*.

The *binding inertia requirements* are for t+3 years out, and these will only use committed projects unless stated in the inertia report.

4.2. Identifying the most significant credible contingencies

To determine the most significant credible contingency, AEMO will perform *power system* analysis to model the largest RoCoF impact from credible contingencies considering the contingency size, the *inertia* lost as a result of the contingency, the momentary cessation in IBR output due to the *voltage* dip as a result of the contingency, and the *load* response as a result of the contingency. Each of these is detailed below.

Contingency size

This step identifies all relevant *credible contingency events* to be tested in the *power system* simulation studies, which can include events such as:

- ***Generation* contingency** – typically a large *generator* with high *inertia*.

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[22] Typically, a PSS®E case from 'AEMO Modelling Platform'.

[23] AEMO. Power system model development, at https://aemo.com.au/en/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations/power-system-model-development.

[24] EPRI. User Guide for Generic Renewable Energy System Models , at https://restservice.epri.com/publicdownload/000000003002027129/0/Product.

- ***Load* contingency** – generally, the largest *load* in an *inertia sub-network* or the NEM would be an industrial *load*, such as a smelter or potline, the size of which is largely uncontrollable via the central *dispatch* process.
- **Separation event** – a credible contingency affecting a *transmission* element that results in an *island*.

Constraint equations that could reasonably be invoked in an *islanded inertia sub-network* or the *power system* to achieve a *secure operating state* will be considered in the maximum contingency size calculation. Examples could be a *constraint* limiting a *generator's* output to manage the largest contingency in the *island*, or restricting *interconnector* flow when a *region* is at credible risk of separation.

Identifying generation contingency

The loss of a *generating unit* with the highest *inertia* will not necessarily result in the *Generation* Contingency that produces the highest RoCoF in the *inertia sub-network*.

When a *contingency event* results in the loss of a *synchronous generating unit*, the effect is two-fold, in that, along with the loss of *generation*, the *inertia sub-network* also loses the *inertia* associated with that *synchronous generating unit*. Likewise, the DPV and *load* reduction as a result of the fault can impact the largest contingency.

Table 3 shows four different *contingency events* affecting four different *synchronous generating units* and RoCoFs. In this example, the pre-contingent *inertia* and demand in the *inertia sub-network* is 15,000 megawatt-seconds (MWs) and 4,100 MW, respectively.

Table 3 Generation and inertia outcomes

Contingency event number	Contingent inertia (MWs)	Loss of generation (MW)	RoCoF (Hz/s)
1	2,500	150	0.30
2	3,200	150	0.32
3	500	175	0.30
4	3,200	100	0.21

Table 3 demonstrates that the highest loss of *inertia* does not always result in the highest RoCoF, and the largest loss of *generation* does not always result in the highest RoCoF. A contingency that leads to the highest RoCoF is the most onerous contingency.

It is also possible that the most significant contingency will be the trip of a large source of FFR, such as BESS. This will also be considered when identifying the most significant *generation* contingency.

Identifying the load contingency

This is typically the largest *load* in the *region* which can be disconnected following a credible contingency disconnecting, usually a smelter.

It is also possible that the most significant contingency will be the trip of a large source of FFR, such as BESS. This will also be considered when identifying the most *load generation* contingency.

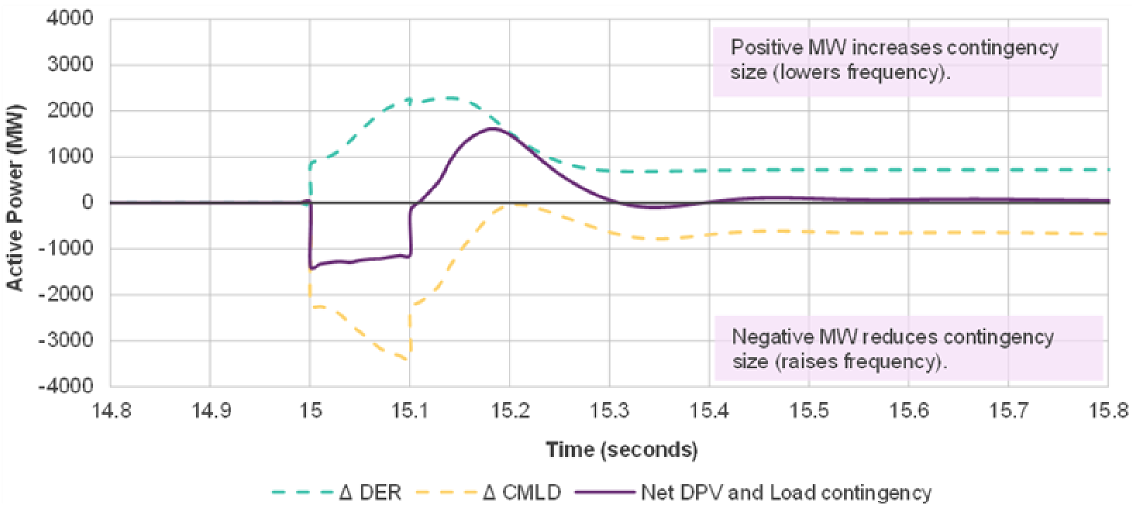
Modelling the DPV and load response

AEMO has developed a 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, compared to previously used static *load* models. AEMO has also developed a DPV model which captures the *voltage*, frequency, and RoCoF response of DPV, providing an accurate representation of DPV momentary cessation and DPV tripping behaviour.

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 2 below shows the impact of DPV, *load*, and a combination of both on the contingency size. After fault clearance, the slower recovery[25] of DPV compared to *load* resulted in an increase in contingency size by approximately 1,500 MW.

Figure 2 Net load and distributed PV response to Tarong North 180 MW contingency in an islanded Queensland



Modelling and quantifying IBR fault ride-through (FRT) response

The installed capacities of large-scale IBR have increased over recent years. During faults, these IBR may enter FRT mode, which involves reducing *active power* output to inject *reactive power* for *voltage* support. The FRT characteristics of large-scale IBR will impact frequency outcomes as the reduction in *generation* can be significant.

Figure 3 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.

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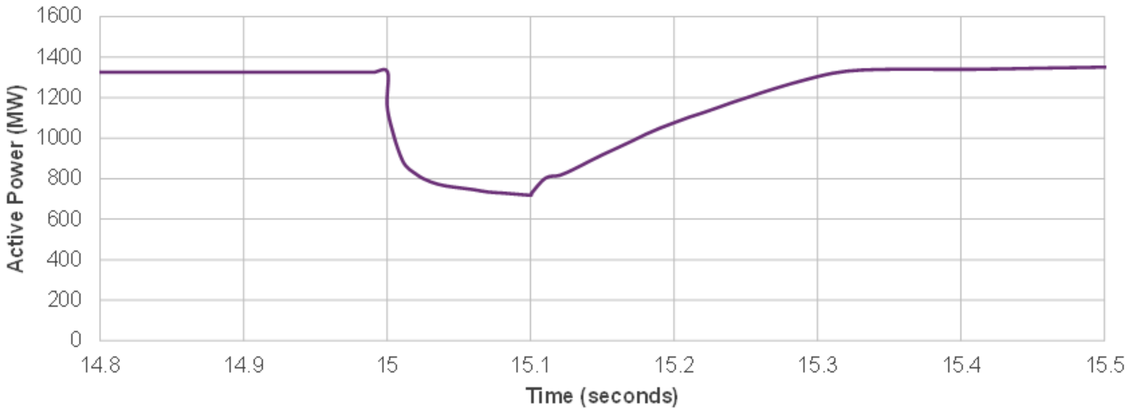
[25] The distributed energy resources (DER) model parameters continuously evolve with the installation of new inverters into the NEM. The parameters used are representative of the study snapshots. In addition, AEMO is undertaking further work to better understand and improve the representation of the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

AEMO uses PSS®E to determine the MW reduction due to fault ride-through. This will be benchmarked against PSCAD™ studies, and any real events, from time to time to ensure accuracy.

Figure 3 Total solar farm generation in a Queensland islanded case under the Tarong North contingency



4.3. Success criteria

The success criteria are conditions that must be met to determine if there is sufficient inertia. The success criteria are ultimately derived by taking into account the *inertia requirements* determined under clauses 5.20B.2(b)(1) and 5.20B.2(b)(4), and relevant matters in determining the *system-wide inertia level* in clause 5.20.4(d1)(1); they can generally be described as the *inertia sub-network*, or the *power system*, being operated continuously in a *secure operating state*.

Specifically, AEMO considers:

- RoCoF and *frequency* requirements specified in the latest version of the FOS are met for all interconnected operating conditions for the system-wide requirements[26], and for each *region* operating as an *island*[27].
- Following any *credible contingency event*, the *power system* or *inertia sub-network* must find a new stable operating point:
  - *Voltages* in the high *voltage transmission network* returned to normal *voltage* ranges.
  - No automatic *load* (under-frequency *load shedding* (UFLS)) or *generation* shedding (over-frequency *generation* shedding (OFGS)) occurred.
  - In-service *transmission* elements remain connected and returned to new steady-state conditions, except for *plant* included in any special control or protection scheme.
  - All in-service *generation* remain connected and returned to new steady-state conditions, except *generators* included in any special control or protection scheme.

[26] See Table A.1. and Table A.2 of Frequency Operating Standard at https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf.

[27] See Table A.5. of Frequency Operating Standard at https://www.aemc.gov.au/sites/default/files/2023-04/FOS%20-%20CLEAN.pdf.

4.4. Calculating the secure inertia level and satisfactory inertia level

A *secure power system* must be in a *satisfactory operating state* and be able to return to a *satisfactory operating state* following any *credible contingency* or *protected event* (NER 4.2.4).

Practically, the *satisfactory* limit is the *inertia* required to be online after the specific worst-case contingency, for the *power system* to return to a *satisfactory operating state*. For example, this could be the *secure* operating level of inertia, minus the *inertia* of the largest *generating unit* providing *inertia* within an *inertia sub-network*.

It should be noted that this *satisfactory inertia level* may require limits on *interconnector* flows while the *inertia sub-network* is at a credible risk of separation.

The *satisfactory inertia level* has been defined under NER 5.20B.2(b)(3). One of the indicators of the *power system* being in a *satisfactory operating state* is defined under NER clause 4.2.2(a) as follows:

the frequency at all energised busbars of the power system is within the normal operating frequency band, except for brief excursions outside the normal operating frequency band but within the normal operating frequency excursion band.

4.5. Determining the sub-network inertia requirements

Power system simulation studies will be performed iteratively to assess the performance of an *inertia sub-network* against the success criteria.

Step 1: Apply contingency

This step applies the contingencies identified in section 4.2 to the PSS®E case. For an *islanded inertia sub-network*, this is typically a *load*, or *generator* in the *sub-network*, and the associated response from IBR and *load*.

Step 2: Check success criteria

Check the *power system* performance against success criteria. A description of how *frequency* and RoCoF are measured is in Appendix D.

This will continue until the success criteria are only marginally passed. ‘Marginally passed’ means the removal of a single additional *synchronous* machine being *dispatched* would result in failure to meet the success criteria.

Step 3: Varying the amount of inertia level studies

If the success criteria are passed (or failed), vary the *inertia* in the case by *re-dispatching synchronous* machines as appropriate. Consequently, *load* and/or IBR *generation* output will also need to be varied to ensure supply and demand is balanced. Return to Step 1 and apply the next contingency.

Step 4: Determining the secure inertia level

Once all contingencies have been assessed, the pre-contingent *inertia* amount that results in the success criteria being marginally passed for the most onerous contingency is the *secure inertia level* for the *inertia sub-network*.

4.6. Determining the system-wide inertia requirements

Power system simulation studies will be performed iteratively to assess the performance of each *sub-network* against the success criteria. The initial *inertia* levels and distribution are set by the *secure level* of *inertia sub-network* values calculated in section 4.5. For example, the *inertia* levels for each *inertia sub-network* based on the 2023 *inertia requirements* are shown in Table 4 below.

Table 4 Inertia sub-network requirements (islanded)

Region	Sub-network inertia requirement (MWs)
Queensland	12,700
New South Wales	10,000
Victoria	15,800
South Australia	5,200

Step 1: Apply contingencies

This step applies the contingencies identified in section 4.2 to the PSS®E case, which can be a *load*, *generator* or *interconnector*. It includes the associated response from IBR and *load*.

For the system-wide requirements, contingencies will be applied in each *sub-network* to ensure the most onerous conditions are studied.

For contingencies which are a fault, the fault clearance times specified in Table S5.1a.2 of the NER will be observed.

Step 2: Check success criteria

Check the *power system* performance against success criteria. A description of how *frequency* and RoCoF are measured is in Appendix D.

This will continue until the success criteria are only marginally passed. 'Marginally passed' means the removal of a single additional *synchronous* machine being *dispatched* would result in failure to meet the success criteria.

Step 3: Vary the amount of inertia system-wide

If the success criteria are passed (or failed), vary the *inertia* amount in the case by re-*dispatching synchronous* machines as appropriate. The distribution of *inertia* in each *inertia sub-network* is kept the same to the extent possible as the *system-wide inertia level* is decreased. For example, if the *system-wide inertia level* is halved, then this should be achieved by halving the *inertia* in each *sub-network* individually[28]. Then return to apply the contingency.

When varying the *inertia* (by *re-dispatching synchronous generator*), *load* and more IBR *generation* output will be varied to ensure supply demand is balanced. Return to Step 1 and apply the next contingency.

[28] Noting that *redispatching* discrete units means it is not possible to maintain the exact same *inertia* distribution.

Step 4: Vary interconnector dispatch

As power flow increases across an *interconnector* following a *contingency event* in a *sub-network,* the amount of 'headroom'[29] the *interconnector* has is important for the success criteria. AEMO will vary the *interconnector dispatch* to ensure the most plausible, onerous conditions are modelled (effectively reducing the headroom).

Return to Step 1 and apply the next contingency.

AEMO notes that some transient stability/oscillatory stability *constraints* include *inertia* which can limit the *interconnector* flow[30]. These limits will be observed in the studies.

Step 5: Determine the system-wide level of inertia

Once all contingencies have been assessed, the pre-contingent *inertia* amount that marginally passes the success criteria for the most onerous contingency is the *secure inertia level* for the *system-wide level* of inertia.

4.6.1. Determine the sub-network allocation

When determining the *inertia sub-network* allocation, NER 5.20B.2(c) requires that AEMO consider a balanced allocation of the *system-wide inertia level* across the mainland NEM.

AEMO will allocate the system-wide level of *inertia* to each *sub-network* based on the *secure level* of *inertia* for each *sub-network* when *islanded* (calculated in section 4.5).

Example sub-network allocation

The illustrative example in Table 5 demonstrates the *inertia sub-network* allocation approach, assuming a *system-wide inertia level* of 30,000 MWs.

Table 5 Inertia sub-network allocation

Region	Sub-network allocation % (based on Table 4)	Subnetwork allocation (MWs)
Queensland	29%	8,719
New South Wales	23%	6,865
Victoria	36%	10,847
South Australia	12%	3,570

4.7. Assess how increasing amounts of FFR can change the inertia

This step involves the use of either a lumped mass model to perform multiple simulations where *inertia* is varied, or appropriate power system modelling such as dynamic studies, to understand the relationships between FFR and *inertia* in each *inertia sub-network*.

[29] Headroom is essentially the overall *interconnector* limit minus the actual *interconnector* flow.

[30] An example *constraint* which limits *interconnector* flow as a function of system *inertia* is V::N_NIL_O2. *Inertia* is not the only factor in these *constraints*.

This section uses FFR as the term to describe the response from batteries (and other fast devices). AEMO notes that the 1s FCAS markets are the primary way these services are procured in the NEM. See section 2.1.5 for more details.

Therefore, it is necessary to consider the availability of FFR when determining the level of *inertia* required to keep the *power system* in a *satisfactory operating state* during interconnected or *islanded* conditions.

Available quantity of FFR

The amount of FFR available largely depends on the number of BESS online where:

(a) The device is online and has headroom to charge or discharge.

(b) *Frequency* response modes are normally enabled, even if not enabled through the 1s FCAS market.

This can differ from the amount of 1s FCAS procured through the market, as the 1s FCAS amount is effectively capped by the raise 6-second (R6) FCAS requirements, which currently do not consider the <1s variations in the contingency, which can occur as described in section 4.2.

The amount of 1s and 6s FCAS provided will reflect the largest credible contingency approach currently implemented in the NEM Dispatch Engine (NEMDE), which includes *load* relief, the largest credible contingency, and any DPV shake off. It does not currently include any FRT or momentary cessation of IBR.

To model 1s FCAS, it is assumed to be wholly provided by existing batteries in the *network* and their response is modelled on their provided models. When additional FFR capability is to be modelled, committed or anticipated BESS projects are used.

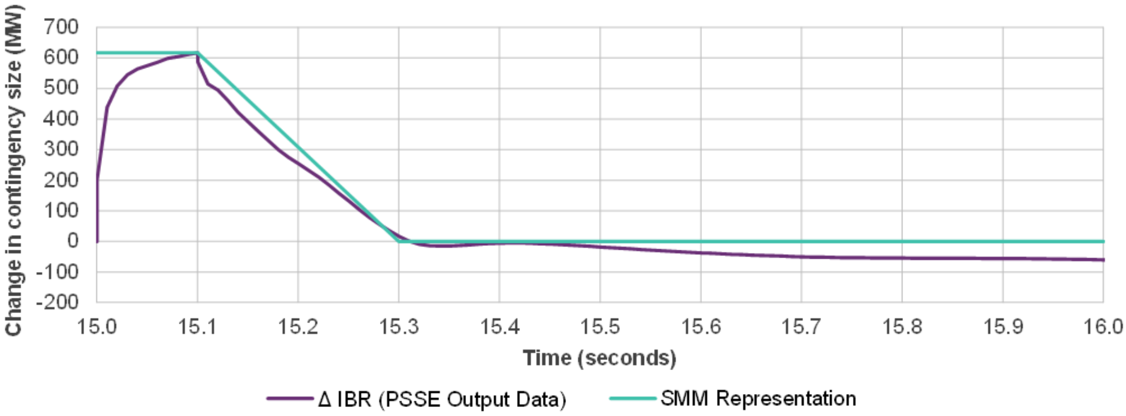
4.7.1. Adjusting the islanded inertia sub-network requirements for FFR quantities

Adjustments to the *islanded sub-network* requirements to account for FFR quantities can be performed using a single mass model (SMM), because the *network* (*interconnectors*) are not relevant. 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.

Tuning the SMM

Given that the SMM does not model concepts such as *network* topology or *voltage*, the output data from the studies in section 4.5 are used to tune the SMM representation to ensure the energy delivered across the first 500 ms after the fault is equal across *power system* simulation software and the SMM. The teal curve in Figure 4 below shows an example of how the IBR FRT response is simplified into a linear representation and modelled in the SMM.

Figure 4 Example IBR fault ride-through representation in SMM

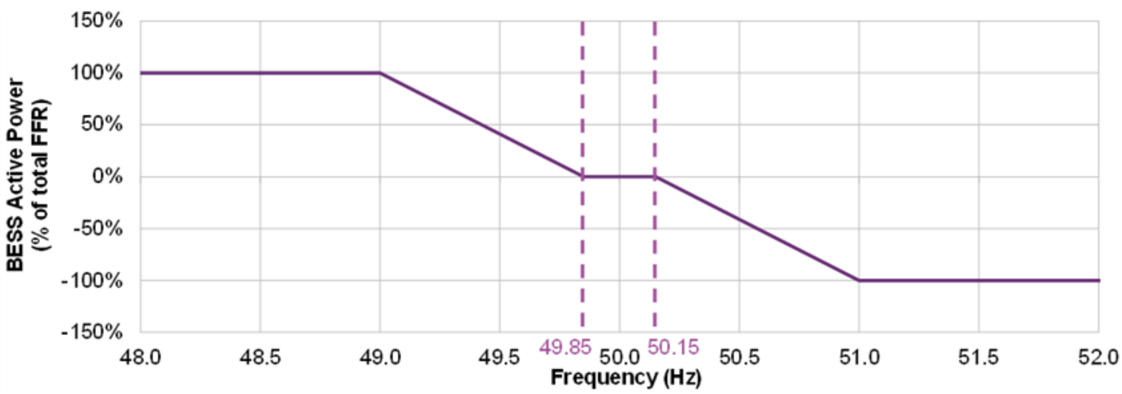


The SMM is tuned by first calculating the areas under the SMM linear graphs and the PSS®E output data for the first 500 ms after the fault. The MW values used in the SMM representation, except for the trip amounts, are then scaled by the ratio *power system* studies area: SMM area until the SMM area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

BESS response

In the SMM, the BESS provides a *frequency-active power* droop[31] response, as shown in Figure 5 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 5 SMM default battery energy storage system droop response in an islanded mainland region



Defining inertia requirements as a function of FFR

The tuned SMM is used to identify a range of FFR and *inertia* combinations that maintain an acceptable *frequency* response. Figure 6 below provides an example of what the relationship between *inertia* and FFR typically looks like. The curve defines a set of operating points that would deliver a *secure level* of

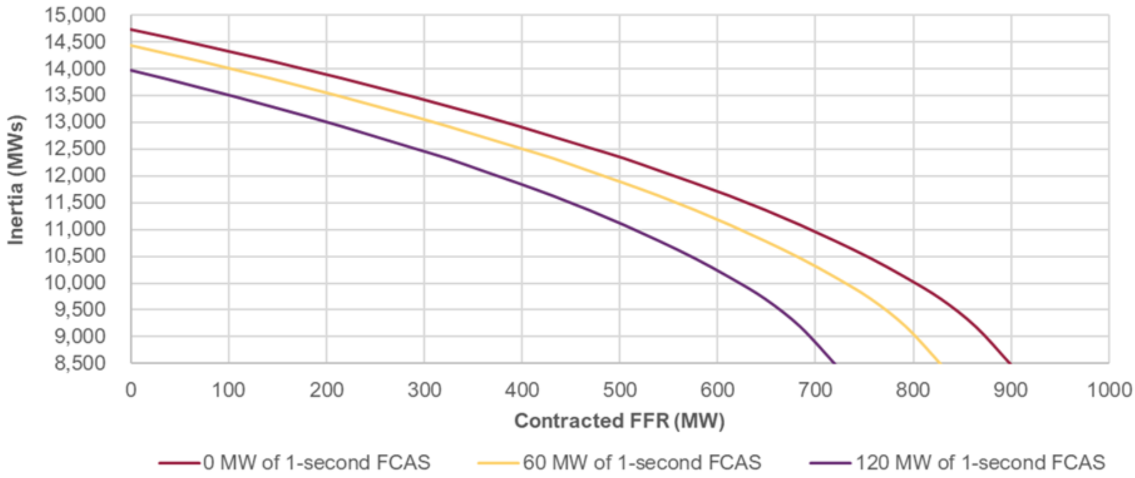
31 This droop response reflects the physical response of BESS with *frequency* droop controllers. This response is typically faster than the response which is represented by ideal triangles in the FCAS markets. In addition, these *plants* typically have greater MW capability than their registered raise 1-second (R1) and lower 1-second (L1) FCAS capabilities.

frequency control, sufficient to meet RoCoF requirements for all *credible contingency events* in the *region*.

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.

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), 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*. For further information on the relationship between the *inertia requirements* and FFR, refer to Appendix C.

Figure 6 Relationship between inertia and FFR in Queensland from 2023 inertia requirements study



4.7.2. Adjusting the system-wide inertia requirements for FFR quantities

Because the *system-wide inertia requirements* need to consider *network* limitations, such as *interconnector* limits, lumped mass models are more complicated to develop.

AEMO proposes not to develop a lumped model to adjust the system wide level of *inertia* for FFR, and proposes instead to add or remove generic batteries to the model, across all the *regions*, to understand the impact of FFR. *Inertia* will be scaled down approximately evenly across the *regions* (subject to unit sizes). It is expected that *interconnector* limits will be a factor, and *interconnector* limits will be observed as per the relevant *constraint* equations.

The success criteria as outlined in section 4.3 will be used to determine the new *secure level* of *inertia* at given FFR quantities.

Appendix A. Inertia Network Services Specification

This appendix describes the *Inertia Network Services specification* as required by NER 5.20.4(f), which must include:

(1) a detailed description of each kind of inertia network service;

(2) the performance parameters and requirements which must be satisfied in order for a service to qualify as the relevant inertia network service and also when an Inertia Service Provider provides the relevant kind of inertia network service; and

(3) the process and requirements for AEMO to approve equipment under paragraph (g).

A.1 Description of inertia network services

AEMO describes an *inertia network service* as a service, made available by means of equipment, which provides a contribution to the capability of the *power system* to resist changes in *frequency* by means of an inertial response. This contribution can be made by a *generating unit*, *bidirectional unit*, *network element* or other equipment, whether *synchronous* or non-synchronous.

A.2 Functional requirements for inertia network services

In accordance with NER 5.20.4(f)(2), AEMO must describe the performance parameters and requirements that must be satisfied by a *plant* to qualify as providing an *inertia network service*, and the conditions under which the *plant* is considered to be providing the *inertia network service*.

A.2.1 Requirements for synchronous plant

The relevant performance parameters for a *synchronous* machine are the mass, spatial distribution, and *synchronous* speed of its rotating components. The *synchronous inertia* of a *synchronous* machine in MWs is the kinetic energy stored at nominal speed which is calculated via

$$\text{inertia (MWs)} \ = 0.5\, J\omega^2$$

where:

- J is the moment of *inertia* in kgm^2
- ω is the nominal speed of rotation in radians per second.

A *synchronous* machine is considered to provide *inertia* whenever it is synchronised with the *power system* at any level of power transfer. The amount of *inertia* provided may vary for some *synchronous plant* operating in different modes with more or less rotational components connected. For example, a *synchronous generator* with a clutch allowing the prime mover to be disengaged for *synchronous condenser* operation may provide less *inertia* due to loss of the prime mover's mass[32].

[32] See https://arena.gov.au/assets/2023/06/repurposing-existing-generators-as-synchronous-condensers-report.pdf.

A.2.2 Requirements for non-synchronous equipment

Non-synchronous equipment covers a broad collection of technologies which may have a wide range of characteristics and parameters relevant to provision of inertia, even when considering just different types and manufacturers of IBR *plant*.

The relevant performance parameters and requirements to quantify an inertial response from IBR *plant* is a relatively new, but quickly evolving area, with rapid advancements being made at the time of *publishing*. As such, AEMO does not deem that there is an appropriate set of performance parameters for the provision of *inertia* from non-synchronous equipment, but rather has set out performance requirements which will be assessed on a case-by-case under the testing process outlined in section A.3 for approval under NER 5.20.4(g).

AEMO *publishes* this *inertia network service specification* acknowledging that advancements in technology and understanding may require more regular updates of this methodology.

AEMO will conduct tests to establish a reference inertia value. Non-synchronous equipment such as IBR *plant* may provide different quantities of *inertia* under different pre-contingent headroom and different size and duration of RoCoF following a *frequency* disturbance. Typically, this difference occurs due to current limits on the device. AEMO acknowledges that the *inertia* provided by non-synchronous equipment may not be a single, constant number.

AEMO will require inertia providers making available *inertia network services* from non-synchronous equipment to specify a reference *inertia* which can be directly referenced against the *inertia requirements* of sections 4.5 and 4.6. The reference *inertia* is the *inertia* provided in response to a 1Hz/s contingency event when operating at the edge of the operational envelope of the device providing the *inertia network service*. AEMO will assess the *reference inertia* for *inertia network services* provided by non-synchronous equipment as part of making an approval under NER 5.20.4(g). Further detail on the range of test conditions AEMO will apply when making an approval under NER 5.20.4(g) is described in section A.3.2.

Important performance requirements for provision of *inertia* from non-synchronous equipment are:

- **Inherency** – the inertial response should be inherent, in accordance with the definition in section 2.1.1. This means that it is initiated by the device resisting a change to the *voltage* angle at its point of *connection* that occurs during a change in system *frequency*. The response may or may not then be shaped over a short timeframe by control system action such as primary *frequency* response, FCAS, or action to keep device output within limits.
- **Headroom** – the amount of *inertia* effectively provided will depend on the energy (megawatt hours (MWh)) and capacity (MW) headroom maintained and the conditions of the *frequency* disturbance. AEMO has not set specific requirements for maintaining headroom, however, AEMO will discuss with inertia providers an active and reactive power operating envelope within which an *inertia network service* is proposed to be provided when requesting an approval under NER 5.20.4(g). This operating envelope will be used to calculate the *reference inertia* for the *inertia network service*. AEMO expects that any headroom arrangements required to provide an *inertia network service* will be managed by the proponent and relevant *Transmission Network Service Provider* (TNSP) through contracts.
- **Performance at higher RoCoF** - AEMO will assess the *reference inertia* of non-synchronous equipment under 1Hz/s contingencies. However, for higher RoCoF frequency disturbances up to

3Hz/s non-synchronous equipment providing an *inertia network service* will still be required to provide *inertia* equal to at least one third of the *reference inertia*. AEMO will use the testing methodology outlined in section A.3.2 to quantify the *inertia* provided at higher RoCoF when making an approval under NER 5.20.4(g).

A.3 Approval process for non-sychronous inertia network services

In accordance with NER 5.20.4(f)(3), AEMO must specify the process and requirements for AEMO to approve non-synchronous equipment under NER 5.20.4(g) to provide *inertia network services*.

A.3.1 Approval request and provision of information to AEMO

Under NER 5.20.4(h), an *Inertia Service Provider* making a request for approval by AEMO under NER 5.20.4(g) must provide the following information to AEMO:

(1) *details of the proposed equipment by means of which an inertia network service will be made available;*

(2) *information about how the inertia network services provided by means of the equipment will contribute to the operation of the relevant inertia sub-network in a satisfactory operating state or secure operating state in accordance with the circumstances described in clause 4.4A.3(b)(2) or (3), as applicable; and*

(3) *any other information requested by AEMO in connection with the request.*

NER 5.20.4(i) gives AEMO discretion to give or withhold approval of equipment, depending on demonstration of the equipment's ability to meet the *inertia service specification*.

AEMO provides the following guidance regarding the requirements and scope of approval requests made under NER clause 5.20.4(g):

- Appropriate electromagnetic transient (EMT) models must be provided to AEMO, which are high quality (usable, robust and accurate), and in accordance with AEMO requirements[33].
- These tests do not test for compliance with requirements under Chapter 5 of the NER, and do not assume that the *plant* can meet existing relevant requirements required to connect to the grid including:
  - Fault ride-through and recovery.
  - *Voltage* control.
  - *Frequency* control.
  - Stability.
  - Operation under partial *load* rejection.

[33] As defined in AEMO. 2018 Power System Model Guidelines, Final report and determination, June 2018. At https://aemo.com.au/- /media/files/electricity/nem/security_and_reliability/system-security-market-frameworksreview/2018/power_systems_model_guidelines_published.pdf?la=en&hash=A3DDF450DBEE1E7C1D7E2E379461538A.

- Additional tests may be requested by AEMO on a case-by-case basis to further demonstrate specific capabilities or to address local concerns depending on the technology under test. These tests are intended to provide a general confidence that the equipment provides the *inertia network service*.
- For clarity, the testing methodology in this *Inertia Network Service Specification* will not, in isolation, confirm whether the equipment is compliant with all relevant performance requirements for *interconnection*. Any applicable requirements may also apply under the:
  - NER, and
  - Dynamic Model Acceptance Test (DMAT) Guideline.

An *Inertia Service Provider* can make a request for approval by AEMO via an email submission to planning@aemo.com.au. Given the novel nature of this type of *inertia network service*, AEMO will assess each request on a case-by-case basis. In future it may be possible to move to a templated approach.

A.3.2 Testing methodology

This section details the testing methodology that AEMO will apply when assessing the equipment for the purposes of considering an approval request.

This testing methodology will be limited to simulations only; AEMO will not require Hardware In Loop (HIL) testing when making an approval under NER 5.20.4 (g). Providers of *inertia network services* will be required to undergo commissioning tests and may be required to provide field data to verify expected performance in response to actual events observed in the power system.

AEMO intends for this testing methodology to be independent of the technology providing the *inertia network service*. This methodology will apply to all non-synchronous equipment including IBR sources such as BESS which are likely to be the primary technology to be tested.

AEMO has drawn heavily on *the Quantifying Synthetic Inertia of a Grid-forming Battery Energy Storage System – Preliminary Report*, *published* by AEMO in September 2024[34], and the Voluntary Simulation Test Framework for Grid Forming Inverters[35], in developing this testing methodology.

The quantification of an inertial response from IBR *plant* is a relatively new but quickly evolving area, with rapid advancements in technology being made at the time of *publishing*. As such, this *Inertia Network Service Specification* may need to be updated regularly. AEMO welcomes working with all stakeholders, including original equipment manufacturers (OEMs) and Network Service Providers (NSPs), more directly if their equipment is under testing to ensure the tests are fit for purpose.

Primary test to quantify inertia

Under NER 5.20.4(g), AEMO may approve equipment that is not a *synchronous* production unit or *synchronous condenser* for provision of *inertia network services*, if AEMO is satisfied that the equipment

[34] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2024/quantifying-synthetic-inertia-from-gfm-bess.pdf?la=en

[35] See https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf?la=en&hash=7778A2249D8C29A95A2FADCD9AAA509D.

will contribute to the operation of the relevant *inertia sub-network* in a *satisfactory* or *secure operating state*[36]. This section describes the means by which AEMO will test the contribution of this equipment.

To isolate the inertial response of the equipment under assessment, frequency control characteristics such as frequency droop control or FCAS enablement will be turned off during testing. Performance in response to frequency disturbances originating from both clean trips and faults will be considered.

Conceptual methodology

The measurement of the *inertia* contribution is based on the *power system* swing equation (with damping ignored[37]), as shown in equation (1)[38] below:

$$\frac{2 \times I}{\omega_s} = \frac{P_{mech} - P_{elec}}{d\omega/dt} \tag{1}$$

where

- I is *inertia* in MWs,
- ω_s is *synchronous* speed in radian per second,
- $Pmech$ and $Pelec$ are the mechanical power into and electrical power out of the *plant(s)* under consideration respectively, both in MW.

Rearranging equation (1), the equivalent *inertia* can be calculated as shown in equation (2) below:

$$I_{total} = \sum_{n=1}^{N} (MW.s_n) = \frac{\Delta P_{MW} \times f}{2 \times RoCoF} \tag{2}$$

where

- I_{total} is the total *inertia* contribution of the system in MWs,
- N is the total number of *plants* in the system providing inertia,
- ΔP_{MW} is the applied *active power* disturbance to the system in MW,
- f is the nominal *frequency* of the system in Hz,
- $RoCoF$ is the rate of change of *frequency* in hertz per second (Hz/s).

Figure 7 shows a conceptual view of the methodology that has been developed based on the above mathematical representation.

It comprises Plant A (whose inertial contribution is to be determined) and Plant B (whose *inertia* is known[39]). When an *active power* imbalance is applied to the system comprised of Plant A and Plant B, the *frequency* of the system will change. This will result in a RoCoF, which depends on the size of the

[36] In accordance with the circumstances described in NER 4.4A.3(b)(2) or (3), as applicable.

[37] Note that, unlike *synchronous generators*, depending on the specific implementation, damping may be essential for stable operation of grid-forming BESS, and thus its implication on *inertia* contribution from grid-forming BESS may require further investigations in future. However, the proposed methodology remains practically robust for determining synthetic *inertia* from the system perspective.

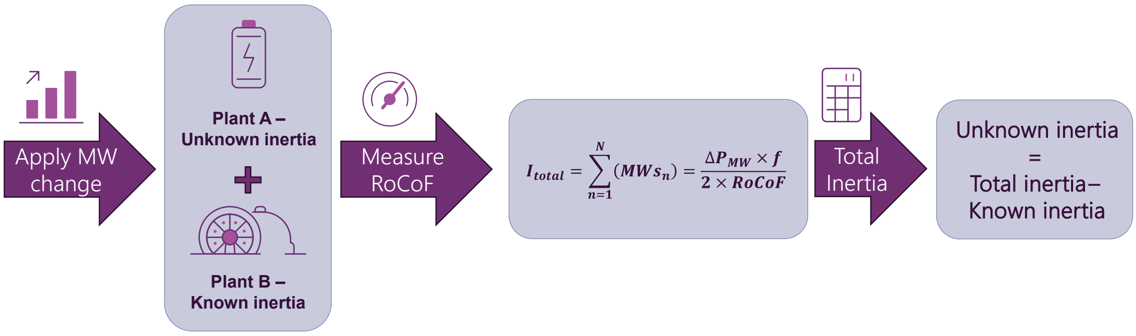
[38] P.M. Anderson, A. A. Fouad, Power System Control and Stability, 2003, Wiley-IEEE Press, pp. 33-40.

[39] This could be a *synchronous generator* whose inertia (MWs) is normally known from the design datasheet or power system model.

disturbance and the inertial contribution from Plant A and Plant B. This RoCoF and the known amount of *active power* disturbance is then used to calculate the total *inertia* of the system (comprised of Plant A and Plant B). As the *inertia* of Plant B is known, the *inertia* of Plant A can be determined by subtracting the Plant B *inertia* from the total calculated inertia.

It should be noted that this methodology emulates near real-world conditions for providing inertial response. That is, an *active power* contingency (for example, *load* or *generation* trip) in the system leads to changes in the *frequency*, RoCoF, and *voltage*. Following a contingency, a *plant* capable of providing inertial response will contribute to total system *inertia* in conjunction with other inertial responses in the system. The *frequency* measurement in the *power system* simulation tools can often be complex, and thus utmost care should be taken by user when calculating RoCoF to quantify synthetic inertia.

Figure 7 Quantification of inertia contribution steps



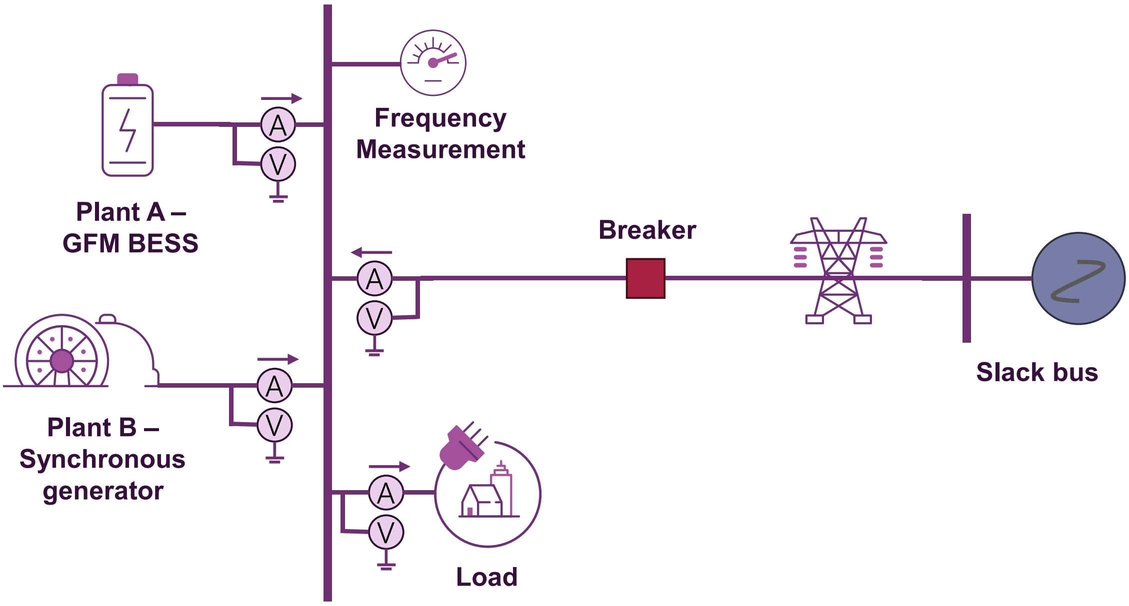
Test system

Figure 8 further illustrates the implementation of the methodology used for this analysis, in an appropriate simulation test setup. A known amount of power imbalance[40] (megawatt change or contingency) is created by opening the breaker at time of t_0 in the test system of Figure 8.

Note that depending on the flow across the *transmission line*, the applied contingency would lead to an under-*frequency* or over-*frequency* event. *Frequency* measurement is then used to calculate the RoCoF over a 500ms rolling window. These values will be plugged back into equation (2) for calculation of total *inertia* (I_{total}). As the *inertia* from Plant B is already known and tested based on the available data sheet, the unknown *inertia* of Plant A can be determined by subtracting Plant B *inertia* from the total calculated inertia.

[40] This can include a fault such as a 2 phase to ground (2ph-g) fault as the cause of this power imbalance.

Figure 8 Schematic representation of the test system using a grid-forming BESS as the plant under test



Test assumptions and inputs

The following assumptions and inputs will be used when applying this test to determine the synthetic *inertia* from grid-forming BESS:

- Model quality of Plant A should be in accordance with AEMO requirements[41].
- The *inertia* of Plant B[42] will be known.
- Since the 'bare-bone' inertial responses of the *plants* are of interest, *frequency* control loops of both *plants* (A and B) will be disabled[43].
- *Load* will be constant power and static *load* (that is, it is not sensitive to *voltage* and *frequency* changes).
- The model will meet existing requirements under Schedule 5.2 of the NER.
- The resultant RoCoF[44] of the overall system in test will be varied up to 3 Hz/s in each direction[45].
- Plant B will be approximately twice the size of Plant A to achieve desirable *dispatch*, RoCoF and operating conditions.

[41] AEMO. Power System Modelling Guideline, July 2024, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2023/power_systems_model_guidelines_2023_published_.pdf.

[42] During this work a *synchronous* machine was used to represent Plant B. It is operating away from any limits (such as Pmin and Pmax) pre- and post-disturbance. Its initial terminal *voltage* is closer to 1.0 per unit (pu). Although during the work site-specific parameters for automatic *voltage* control (AVR) and Power System Stabiliser (PSS) have been used, a generic parameter setup is not expected to impact the proposed methodology.

[43] For a *synchronous generator* model, the governor should be disabled. For IBR, *frequency* control response (such as FFR) should be disabled.

[44] Measured over 500 ms window.

[45] This 3 Hz/s RoCoF value comes from Requirement 9 of Table A2 of the FOS.

Test schedule

Table 6 and Table 7 provides high-level guidance on the test setup, initial checks, and approach for the simulation. The measured values are then replaced in equation (2) solving for the *inertia* contribution from a grid-forming BESS. There are two types of disturbances tested:

(1) A 'clean' trip, where there is a power imbalance, without an associated *voltage* dip associated with the application of a fault.

(2) A fault, where there is a 2 phase to ground (2ph-g) fault applied (on the *transmission* system), and then an associated power imbalance because of the fault being cleared.

Table 6 Test bench setup in the simulation for a 'clean' trip

Initial setup
• Set up the simulation case as shown in Figure 8.
• If applicable, test the *plant* under its full range of P and Q outputs.
• Set up *generation* from Plant A, Plant B and *load* such that desired contingency (*active power* change) is flowing through the transmission line. – This contingency will be varied to result in a RoCoF range from -3 Hz/s to +3 Hz/s.
• Disable the control loops in the model which acts on the measurement of *frequency* and provides *frequency* control.
Test Sequence 'clean trip'
1. Run the simulation until a steady state is achieved.
2. Open the breaker at $t = t_0$.
3. Measure the RoCoF* in the system.
Simulation checks
• Plants' *active power* outputs match desired *dispatched* levels.
• *Frequency* should initially be 1 per unit (pu).
• *Voltages* across the system is as expected.
• There should not be oscillations in the system.
• *Reactive power* output from all devices should be within limits.
Determining inertia
• Calculate the total *inertia* in the system based on the applied contingency and measured RoCoF*.
• Subtract the known *inertia* of Plant B from the total calculated *inertia* to obtain the *inertia* contribution from Plant A.
• Check the *active power* response over 2 seconds.

* During this work, a 500 ms rolling window will be used to calculate RoCoF.

Table 7 Test bench setup in the simulation for a 'fault'

Initial setup
• Set up the simulation case as shown in Figure 8.
• If applicable, test the *plant* under its full range of P and Q outputs.
• Set up *generation* from Plant A, Plant B and *load* such that desired contingency (*active power* change) is flowing through the *transmission line*. – This contingency will be varied to result in a RoCoF range from -3 Hz/s to +3 Hz/s.
• Disable the control loops in the model which acts on the measurement of *frequency* and provides *frequency* control.
Test Sequence 'clean trip'
1. Run the simulation until a steady state is achieved.

2. Apply 2ph-g fault on the *transmission* system side of the breaker in Figure 8.	
3. Open the breaker to clear the fault according to maximum allowable clearance time in Table S5.1a.2 of the NER and proposed point of *connection voltage* of the *plant* under test.	
4. Measure the RoCoF* in the system.	
Simulation checks	
• Plants' *active power* outputs match desired *dispatched* levels.	
• *Frequency* should initially be 1 pu.	
• *Voltages* across the system is as expected.	
• There should not be oscillations in the system.	
• *Reactive power* output from all devices should be within limits.	
Determining inertia	
• Calculate the total *inertia* in the system based on the applied contingency and measured RoCoF*.	
• Subtract the known *inertia* of Plant B from the total calculated *inertia* to obtain the *inertia* contribution from Plant A.	
• Check the *active power* response over 2 seconds.	

* During this work, a 500 ms rolling window will be used to calculate RoCoF.

A.3.3 Additional tests to ensure robust delivery

It is important to ensure that the equipment providing the inertial response performs robustly under a range of conditions. To ensure this, AEMO will consider whether equipment that is an IBR providing an inertial response meets the Voluntary Specification for Grid Forming Inverters: Core Requirements Test Framework[46]. AEMO will draw from this voluntary specification where required for additional tests in addition to the tests outlined in this appendix. Additional tests will include assessing the equipment's response to a phase angle jump. Additional tests will be limited to simulations only; AEMO will not require Hardware In Loop (HIL) testing when making an approval under NER 5.20.4 (g). Providers of *inertia network services* will be required to undergo commissioning tests and may be required to provide field data to verify expected performance in response to actual events observed in the power system.

[46] At https://aemo.com.au/-/media/files/initiatives/engineering-framework/2023/grid-forming-inverters-jan-2024.pdf?la=en&hash=7778A2249D8C29A95A2FADCD9AAA509D.

Appendix B. 1-second FCAS translation into FFR capability

Services provided by 1s FCAS markets have been included in the modelling approach in this Methodology, however it is important to understand that for BESS providing 1s FCAS, there is a definitional distinction between their total FFR capability and the MW capacity registered in the 1s 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 1s 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* (MASS), being the change in power due to its droop setting at the lower or raise reference *frequency*[47]. For a typical droop setting of 1.7%, this works out as a 1s FCAS capacity of about 57% of FFR capability[48].

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

This translation between 1s 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 1s FCAS capacity and contracted FFR capability is 1 to 1 for these technologies.

B.1 Worked example

A *region* with the following 1-second FCAS registrations has approximately 94 MW of FFR capability:

Table 8 Worked example of translating FFR to 1s FCAS

Station name	Bid type	Registered max cap (MW)	Controller	Calculated FFR
BESS 1	Raise1sec	40	Droop (1.7%)	40/0.57 = 72
Switched *Load* A	Raise1sec	10	Switched	10
Switched *Load* B	Raise1sec	12	Switched	12

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

[48] 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.

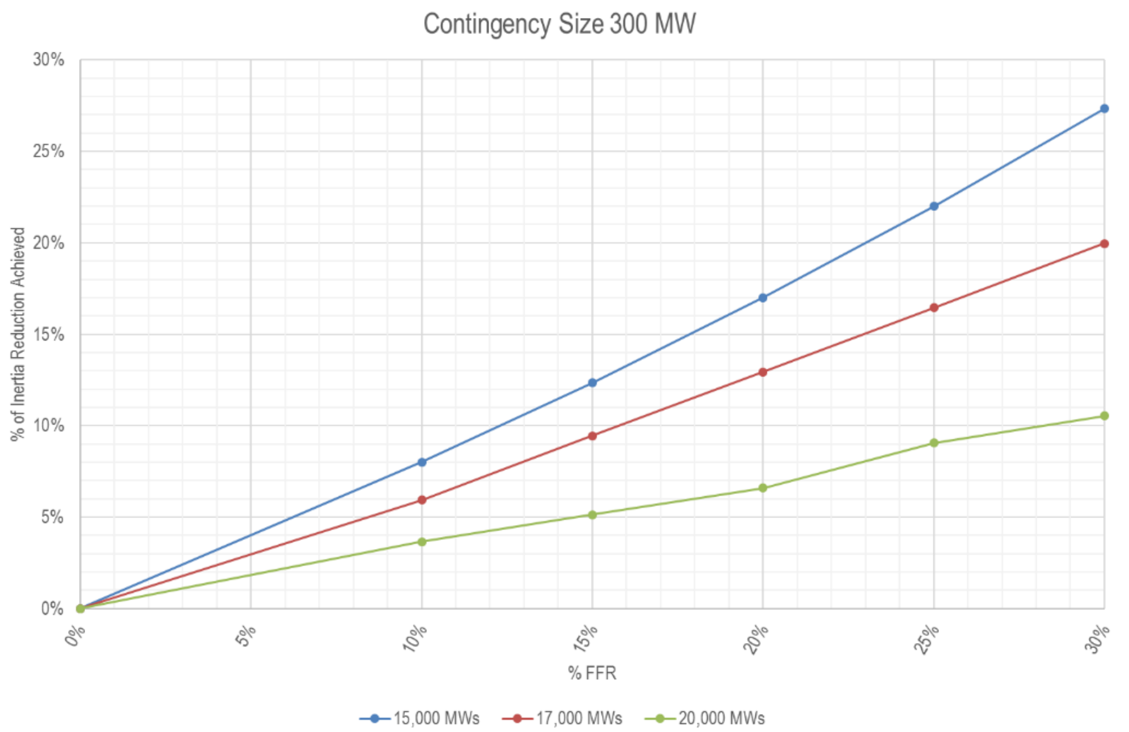
Station name	Bid type	Registered max cap (MW)	Controller	Calculated FFR
			Total FFR	94

Appendix C. Impact of FFR on inertia requirements

There is a relationship between the speed of delivery of an FCAS response, and the required level of system *inertia*. However, conditions of low *inertia* also increase the RoCoF following a contingency. If required *inertia* levels are reduced due to faster delivery of an FCAS response, the resultant high RoCoF could itself be a limiting factor for operation of the *power system* in a *secure operating state*.

As described in section 2.1, *inertia support activities* that rely on the measurement of *frequency* to increase/decrease their output need a minimum time to operate successfully, and this becomes increasingly challenging under high RoCoF conditions. Additional delays also arise due to devices' deadbands. In the example below, the response to a contingency with 1 Hz/s RoCoF starting from 50 Hz would not begin until 300 ms after the contingency occurs, due to the combination of deadband and measurement time delays.

Figure 9 Relationship between FFR and inertia



C.1 Worked example

An example analysis has been undertaken to assess the impact of FFR on *inertia requirements*. During this analysis an FFR model with the following settings has been used, which results in the in full activation of the response by the time *frequency* reaches 49 Hz or 51 Hz:

- Negligible response delay or ramp rate restrictions once activated.
- *Frequency* deadband of +/- 150 millihertz (mHz).
- 1.7% *frequency* droop.

- Measurement time delay of 150 ms[49].

To assess the impact of FFR on *inertia requirements*, this generic FFR model was integrated into the SMM, and the total Fast FCAS response was divided into two components:

- Fast FCAS delivered as per the requirements set out in the MASS[50]; and
- FFR that represents the FFR model explained above.

To understand the relationship between the amount of FFR and the *inertia requirements*, the percentage contribution from FFR to the total required Fast FCAS response was varied. For each case, a revised *inertia requirement* was calculated to maintain Acceptable Frequency.

Figure 9 shows the relationship between FFR and *inertia* reduction that could be achieved to maintain an Acceptable Frequency. The horizontal axis shows the percentage FFR from the total Fast FCAS that was *dispatched*. As an example, 30% indicates 30% FFR and 70% Fast FCAS. The vertical axis shows the percentage of *inertia* reduction that can be achieved. As an example, 10% indicates that 10% less *inertia* is required to maintain Acceptable Frequency.

Figure 9 demonstrates that FFR is more effective for low *inertia* systems compared to high *inertia* systems. As an example, for a contingency size of 300 MW, *dispatching* 20% FFR from total Fast FCAS would provide 6.5% and 17% reduction in the *inertia requirements* for an *inertia sub-network* with 20,000 MWs and 15,000 MWs *inertia*, respectively.

Figure 10 shows the relationship between FFR and contingency size and demonstrates that FFR is more effective for larger contingencies.

Figure 11 shows the relationship between FFR and RoCoF. The horizontal axis shows the percentage of FFR from the total FCAS *dispatched*. While a higher percentage of FFR can achieve a reduction in the *inertia requirements*, as shown in Figure 9, it will also increase the RoCoF as shown in Figure 11.

Figure 11 highlights that for a contingency size of 300 MW, only 15% of fast FCAS can be *dispatched* as FFR for an *inertia sub-network* with 10,000 MWs *inertia* to limit RoCoF to 1 Hz/s. However, for the same contingency size, 50% of Fast FCAS can be *dispatched* as FFR for an *inertia sub-network* with 15,000 MWs *inertia* to limit RoCoF to 1 Hz/s.

This analysis shows that for reducing *inertia requirements*, FFR is more effective for low *inertia* system with large contingency size. However, a low *inertia* system with a large contingency size is exposed to high RoCoF, which could be a limiting factor in the accurate delivery of FFR.

[49] Some measurement units can accurately measure signal value quicker than 150 ms.

[50] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/2024/market-ancillary-services-specification---v82-effective-3-june-2024.pdf?la=en.

Figure 10 Relationship between FFR and contingency

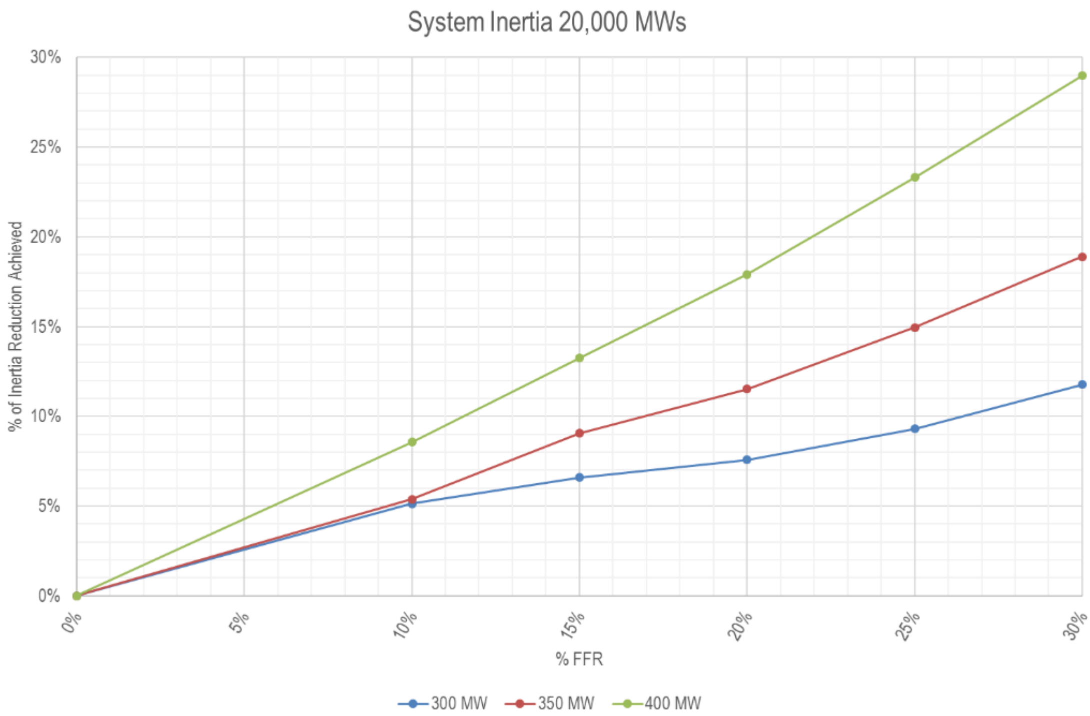
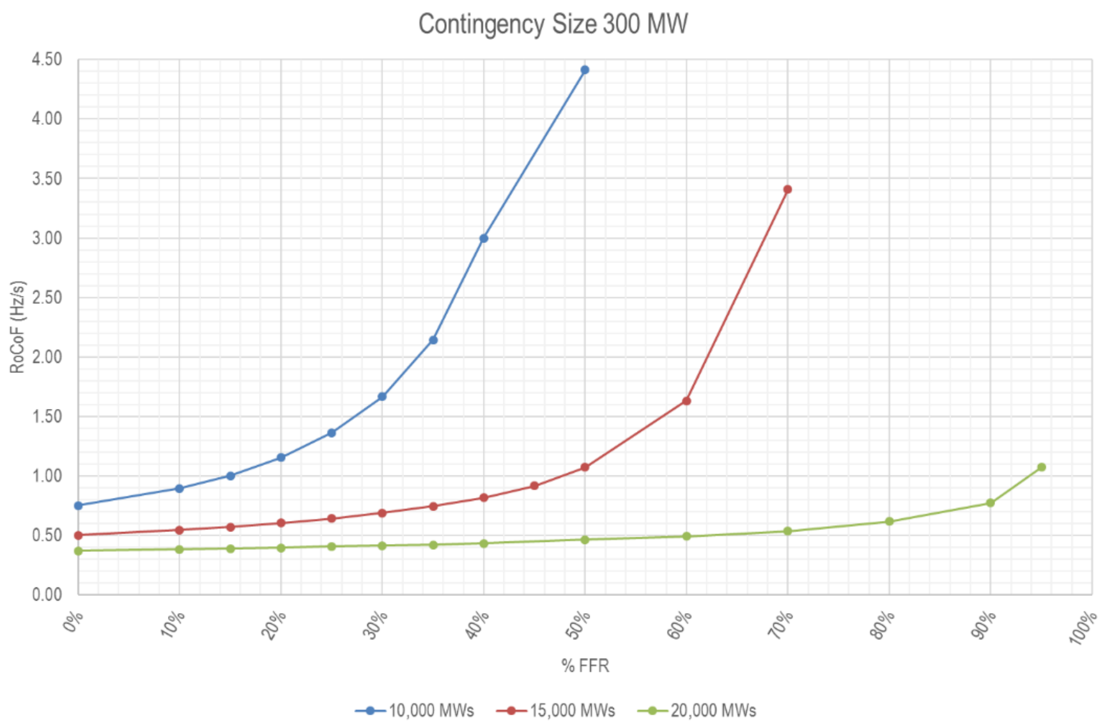


Figure 11 Relationship between FFR and RoCoF



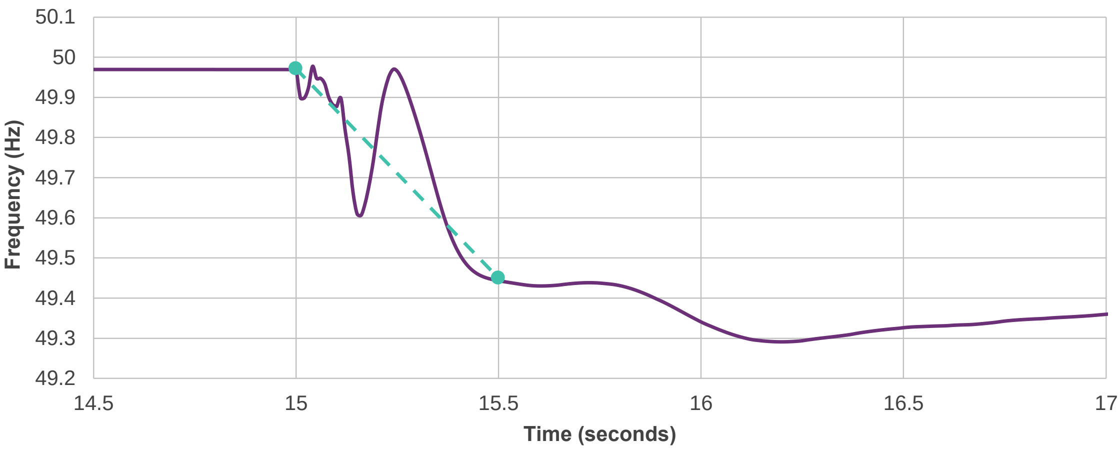
This analysis indicates the potential for FFR-type technologies to reduce the *inertia requirements* for an *inertia sub-network*. For an *inertia sub-network* that typically has low *inertia* compared to the largest contingency size, FFR is more effective at reducing the *inertia requirements* than in an *inertia sub-network* with typically high levels of *inertia*. However, a low *inertia* system would be constrained by

RoCoF, which would then limit the extent to which FFR could reduce the *inertia requirements*; that is, a certain level of *inertia* provided by *synchronous* machines or equivalent (such as grid-forming BESS) will still be required.

Appendix D. Frequency and RoCoF calculations

D.1 Rate of change of frequency measurement over 500 ms period

Figure 12 Measuring RoCoF



D.2 Measuring frequency and RoCoF

Frequency and RoCoF for each *inertia sub-network* is measured by averaging the *frequency* at all buses with *voltage* greater than or equal to 275 kV in each *inertia sub-network*, and short-term transients are disregarded. This 'low pass filter'[51] approach can be seen in Figure 12. Generally, the highest RoCoF is expected to occur following *contingency events* during low demand periods with low *synchronous generation dispatch*.

[51] This straight line approach mimics the low pass filtering approach which protection relays perform, without creating unnecessary complications by trying to mimic the exact filtering approaches used by different OEMs.

Version release history

Version	Effective date	Summary of changes
1.0	1 July 2018	First issue