INERTIA REQUIREMENTS METHODOLOGY

INERTIA REQUIREMENTS & SHORTFALLS

PREPARED BY: Operational Analysis and Engineering, AEMO

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TITLE: Executive General Manager, Operations

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<tr>
<td>1.0</td>
<td>1 July 2018</td>
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EXECUTIVE SUMMARY

*Power systems* with high *inertia* can resist large changes in the *power system frequency* arising from *contingency events* that lead to an imbalance in supply and demand.

At present, AEMO does not *dispatch inertia*. Instead, AEMO uses *constraint equations* to limit the rate of change of *power system frequency* in vulnerable *regions* by controlling *interconnector flows*. This measure will remain in place after the commencement of the National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9 (*Inertia Rule*). The Inertia Rule establishes a framework for the management of *inertia*. From 1 July 2018, TNSPs that are *Inertia Service Providers* will have an obligation to provide *inertia network services*.

AEMO is now required to calculate the *inertia requirements* for each *inertia sub-network* in accordance with the *inertia requirements methodology*. The *inertia requirements* are specified as:

- 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*.

Upon determining the *inertia requirements* for each *inertia sub-network*, AEMO is required to determine whether there are any *inertia shortfalls* in each *inertia sub-network*.

**Inertia sub-networks**

Under clause 11.100.2 of the NER, the *regions* are the initial *inertia sub-networks*.

**Minimum and secure level of inertia**

AEMO has calculated the *minimum threshold level of inertia* and *secure operating level of inertia* for each *region* when *islanded*. In determining the required level of *inertia*, AEMO has considered the following factors to reduce the level of *inertia* otherwise needed:

- The largest *credible contingency event* when a *region* is operating as an *island*.
- The level of Contingency FCAS available in each *region*.

**2018 Inertia shortfalls**

Using the methodology detailed in this document to calculate the *inertia requirements* and determining the *inertia shortfalls*, AEMO has not identified any *inertia shortfalls* for 2018.
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Figure 1 Interrelationship of inertia framework components with other power system security requirements | 9
1. INTRODUCTION

1.1. Purpose and scope

AEMO publishes in this document the:

(a) inertia requirements methodology determined under clause 11.100.3(a) of the National Electricity Rules (NER) (Methodology); and

(b) inertia requirements and inertia shortfalls determined under clause 11.100.4(a) of the NER.

This Methodology, the inertia requirements and inertia shortfalls have effect only for the purposes set out in the NER. The NER and the National Electricity Law prevail over this Methodology to the extent of any inconsistency.

1.2. Definitions and interpretation

1.2.1. Glossary

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

Terms defined in the National Electricity Law and the NER have the same meanings in this Methodology unless otherwise specified.

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.

<table>
<thead>
<tr>
<th>Term</th>
<th>Definition</th>
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<tr>
<td>Acceptable Frequency</td>
<td>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 excursion band.</td>
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<tr>
<td>Contingency FCAS</td>
<td>Each of the following: fast raise service; fast lower service; slow raise service; slow lower service; delayed raise service; and delayed lower service.</td>
</tr>
<tr>
<td>EMT</td>
<td>Electromagnetic transient.</td>
</tr>
<tr>
<td>EMTDC</td>
<td>Electromagnetic transients, including Direct Current.</td>
</tr>
<tr>
<td>Fault Levels Rule</td>
<td>National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10.</td>
</tr>
<tr>
<td>Fast FCAS</td>
<td>Fast raise service and fast lower service.</td>
</tr>
<tr>
<td>FCAS</td>
<td>Frequency control ancillary services.</td>
</tr>
<tr>
<td>FFR</td>
<td>Fast frequency response.</td>
</tr>
<tr>
<td>FRT</td>
<td>Fault ride-through</td>
</tr>
<tr>
<td>Generation Contingency</td>
<td>As defined in section 11.2</td>
</tr>
<tr>
<td>Inertia Rule</td>
<td>National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No. 9.¹</td>
</tr>
<tr>
<td>Load Contingency</td>
<td>As defined in section 11.2</td>
</tr>
<tr>
<td>MASS</td>
<td>Market ancillary service specification.</td>
</tr>
<tr>
<td>Minimum Operating Level</td>
<td>As defined in clause S5.2.5.11 of the NER.</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatt</td>
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</tbody>
</table>

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

<table>
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<th>Location</th>
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2. CONTEXT
This Methodology specifies the process AEMO has used to determine the inertia requirements for each inertia sub-network for 2018 and the process it intends to use for 2019 and beyond.

Figure 1 shows the interrelationship between this document and other NER instruments and AEMO guidelines, operating procedures and activities. By no means a complete depiction, it highlights how this Methodology fits in with a number of existing and new requirements on AEMO’s ability to meet its power system security responsibilities.
Figure 1  Interrelationship of inertia framework components with other power system security requirements

- **Power System Security**
  - System Standards
  - Power System Model Guidelines
    - Power System Design Data Sheets
    - Power System Setting Data Sheets
  - Performance Standards
  - Power System Operating Procedures
    - Stability
    - Voltage
    - Frequency
    - System Strength
    - Inertia
    - Ancillary services
    - Reserve

Legend:
- This document
- AEMO documents
- Actions required by the NER
- System security components
- Out of scope for Inertia
2.1. Relationship with other processes and documents

2.1.1. Frequency Operating Standard

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. Both of these parameters depend, among other things, on AEMO’s ability to maintain power system frequency within certain parameters.2

Although referred to as the frequency operating standard, there are, in fact, two standards, one for the mainland regions and one for Tasmania.

The frequency operating standard 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.

2.1.2. System Strength Requirement Methodology and System Strength Requirements

From 1 July 2018, the National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10 (Fault Levels Rule) creates a framework in the NER for the management of system strength in the NEM.

The Fault Levels Rule prescribes the process AEMO must follow to determine the base level of system strength in each region, called the system strength requirements, by reference to the three phase fault level at fault level nodes within each region. The minimum fault levels at these fault level nodes become a proxy for determining how much system strength is necessary for the power system to be maintained in a secure operating state.

Where a fault level shortfall exists, TNSPs will be required to procure system strength services to maintain the minimum fault levels and Generators and MNSPs will be required to contribute towards the maintenance of system strength to the extent that their new or modified connections have an adverse system strength impact.5

AEMO will use the system strength requirements methodology to assess whether a fault level shortfall exists, or is likely to exist in the future.

System strength and inertia are related because they can both be enhanced by dispatching Synchronous Machines. Therefore, there may be a correlation between the system strength requirements and inertia requirements, as well as any fault level shortfalls and inertia shortfalls. It should be noted, however, that there are mechanisms to address inertia shortfalls that have no impact on system strength, such as under-frequency load shedding or FFR.

2.1.3. 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.

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2 See clause 4.2.2(a) of the NER.
3 Available at: https://www.aemc.gov.au/sites/default/files/content/c2716a96-e099-441d-9e46-8ac05d365a7/REL0065-The-Frequency-Operating-Standard-stage-one-final-for-publi.pdf
5 See clause 5.20C.3(b) of the NER.
3. BACKGROUND

3.1. The concept of inertia

3.1.1. What is inertia?

Inertia is defined in the NER\(^7\) as:

Contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is electro-magnetically coupled with the power system and synchronised to the frequency of the power system.

3.1.2. Inertia and rate of change of frequency

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 rate of change of frequency (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 RoCoF:

(a) reduce the size of the contingency event by reducing generation output, load consumption or limiting interconnector flow;

(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 49Hz

<table>
<thead>
<tr>
<th>RoCoF (Hz/s)</th>
<th>Time to reach 49 Hz(^8) (seconds)</th>
</tr>
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<tbody>
<tr>
<td>4</td>
<td>0.25</td>
</tr>
<tr>
<td>2</td>
<td>0.5</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>0.5</td>
<td>2</td>
</tr>
</tbody>
</table>

The power system needs additional measures to bring frequency back within its normal operating frequency band and AEMO currently uses Contingency FCAS for this purpose. To allow a higher level of RoCoF, faster correction of the imbalance between supply and demand is required. The timeframe of this correction needs to be faster than the fast raise service or fast lower service.

These types of corrections are often termed ‘fast frequency response’ (FFR). FFR requires accurate and reliable measurements of frequency. Time delays associated with the accurate measurement of frequency to facilitate an active FFR-type response would require sufficient inertia to be online prior to the contingency events.

3.1.3. 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.

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\(^8\) Starting from 50 Hz.
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.

Because they spin synchronously with the power system, they inherently slow down a change in power system frequency immediately after an imbalance between supply and demand. 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.

3.1.4. Asynchronous generation

On the other hand, asynchronous generation technologies, such as modern wind turbines, solar inverters and batteries, are connected to the power system via a power electronic interface and do not bring any inertia naturally to the power system because they are electrically decoupled from the power system. Most modern asynchronous generation technologies can be designed to provide frequency control capability in the same fashion as Synchronous Machines, however, most existing and committed asynchronous generation in the NEM has not been designed with this capability.

Because of a lack of inherent inertia, these technologies are currently limited in their ability to reduce a change in power system frequency immediately after an imbalance between supply and demand.

3.1.5. Synchronous condensors

Synchronous condensors are synchronously connected to the power system and provide inertia to the power system. However, they do not have ability to provide FCAS, being as important aspect of inertia requirement, as it will assist in bringing the frequency back within normal operating frequency band.

3.1.6. Why inertia is important in the NEM

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

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

A further characteristic of inertia is that it is a global quantity. This means that, across the NEM, as long as there are sufficient Synchronous Machines online across all synchronously interconnected regions, there will be no shortage of inertia. If a region separates from the rest of the NEM and operates as an island, however, that region has to rely on locally available inertia to maintain security.

4. HOW AEMO ADDRESSES INERTIA

4.1. Prior to commencement of the Inertia Rule

At present, AEMO does not dispatch inertia. Instead, AEMO uses constraint equations to limit the RoCoF in a vulnerable region by controlling interconnector flows. This measure will still remain in place after the commencement of the Inertia Rule.

4.2. Following commencement of the Inertia Rule

The Inertia Rule establishes a framework for the management of inertia.

From 1 July 2018, TNSPs that are Inertia Service Providers will have an obligation to provide inertia network services if an inertia shortfall has been identified.

5. THE INERTIA RULE

The Inertia Rule imposes several new responsibilities on AEMO. The following are the most pertinent:

- AEMO is required to develop and publish an inertia requirements methodology to determine the inertia requirements for each inertia sub-network by 30 June 2018 (clause 11.100.3(a)).

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9 Clauses 4.3.4(j) and 5.20B.4(a) of the NER
Following 1 July 2018, AEMO is required to publish an inertia requirements methodology annually as part of the NTNDP and, using that methodology, to:

- determine the boundaries of inertia sub-networks (clause 5.20.1(a)(3));
- determine the inertia requirements for each sub-network (clause 5.20B.2(a));
- assess any current inertia shortfall and forecast any inertia shortfall arising within a planning horizon of at least five years (clause 5.20.2(c)(13)).

If AEMO determines that there is, or likely to be, an inertia shortfall in an inertia sub-network, AEMO must publish that determination and give to the relevant Inertia Service Provider a notice of the assessment along with the date by which the Inertia Service Provider must ensure the availability of inertia network services (clause 5.20B.3(c)).

6. INERTIA SUB-NETWORKS

Under clause 11.100.2 of the NER, the regions are the initial inertia sub-networks.

7. DETERMINING INERTIA REQUIREMENTS

7.1. Defining the inertia requirements

Clause 5.20.B.2(b) of the NER requires AEMO to calculate the inertia requirements for each inertia sub-network in accordance with the inertia requirements methodology. The inertia requirements are specified as:

(a) 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

(b) 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.

7.2. Minimum threshold level of inertia

The minimum threshold level of inertia is defined as the minimum level of inertia required to operate an islanded inertia sub-network in a satisfactory operating state.

One of the indicators of the power system being in a satisfactory operating state is that 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 excursion band (Acceptable Frequency).

Hence, to be in a satisfactory operating state, while islanded, an inertia sub-network must maintain an Acceptable Frequency.

Note that the impact of the loss of interconnection causing formation of a viable island was not accounted for because the Inertia Rule allows constraining interconnector flow down to zero when there is a credible risk of separation.

7.3. Secure operating level of inertia

The secure operating level of inertia is defined as the minimum level of inertia required to operate an islanded inertia sub-network in a secure operating state.

The power system is defined as being in a secure operating state if, in AEMO’s reasonable opinion, taking into consideration the appropriate power system security principles described in clause 4.2.6, the power system:

10 Future iterations of this Methodology will include AEMO’s determination of inertia sub-networks as required by clause 5.20B.1(b) of the NER.
11 Clause 5.20B.2(b)(1) of the NER.
12 Clause 4.2.2(a) of the NER.
13 Clause 5.20B.2(b)(2) of the NER.
8. INERTIA SHORTFALL

8.1. Determining Inertia Shortfall

Once the inertia requirements for an inertia sub-network have been determined, clause 5.20B.3(a) of the NER requires AEMO to assess:

1. the level of inertia typically provided in the inertia sub-network having regard to typical patterns of dispatched generation in central dispatch;
2. whether in AEMO’s reasonable opinion, there is or is likely to be an inertia shortfall in the inertia sub-network and AEMO’s forecast of the period over which the inertia shortfall will exist; and
3. where AEMO has previously assessed that there was or was likely to be an inertia shortfall, whether in AEMO’s reasonable opinion that inertia shortfall has been or will be remedied.

In making this assessment, AEMO must take into account the following factors:

1. over what time period and to what extent the inertia that is typically provided in the inertia sub-network is or is likely to be below the secure operating level of inertia;
2. the levels of inertia that are typically provided in adjacent connected inertia sub-networks and the likelihood of the inertia sub-network becoming islanded; and
3. any other matters that AEMO reasonably considers to be relevant in making its assessment.

8.2. Inertia Network Services to address Inertia Shortfall

To address an inertia shortfall, TNSPs that are Inertia Service Providers will need to provide inertia network services under clause 5.20B.4(b) to the secure operating level of inertia (as adjusted for inertia support activities), but not less than the minimum threshold level of inertia as adjusted for inertia support activities. Any proposed investments made to provide inertia network services are subject to a regulatory investment test for transmission\textsuperscript{15} as are any proposed inertia service payments\textsuperscript{16}.

8.2.1. Inertia Network Services up to the Minimum Threshold Level of Inertia

The inertia network services that qualify to provide inertia up to the minimum threshold level of inertia are:

1. through the installation, commissioning and operation of a synchronous condensor; and
2. those made available to the Inertia Service Provider by a Registered Participant and provided by means of a synchronous generating unit or a synchronous condensor under an inertia services agreement.\textsuperscript{17}

\textsuperscript{14} Clause 4.2.4(a) of the NER.
\textsuperscript{15} Clause 5.16.3(a)(10).
\textsuperscript{16} Clause 5.16.3(a)(9).
\textsuperscript{17} Clause 5.20.B.4(d) of the NER.
8.2.2. Inertia Network Services up to the Secure Operating Level of Inertia

The inertia network services that qualify to provide inertia beyond the minimum threshold level of inertia up to the secure operating level of inertia are:

1. the inertia network services referred to in Section 8.2.1;
2. the installation of network equipment other than synchronous condensors; and
3. those made available to the Inertia Service Provider by a Registered Participant under an inertia services agreement other than those referred to in Section 8.2.1.18

9. INERTIA SUPPORT ACTIVITIES

Inertia support activities are relevant in adjusting the inertia requirements where AEMO forecasts an inertia shortfall.

Clause 5.20B.5(b) of the NER allows:

An adjustment to the minimum threshold level of inertia or the secure operating level of inertia for inertia support activities will apply to the level determined by AEMO and only where and to the extent that the approved activity is enabled and performing in accordance with the conditions of any approval determined by AEMO.

Appendix G discusses the relationship between inertia support activities and how they can assist in reducing the inertia requirements in an inertia sub-network.

AEMO will only accept an inertia support activity where it is or has been installed and is enabled solely in the circumstances described in clause 4.4.4(a) and (b) of the NER. This means that any activity using plant installed prior to 1 July 2018 that would otherwise be eligible as an inertia support activity will not be considered to be an inertia support activity.

There are presently three types of inertia support activities that AEMO will consider if requested by an Inertia Service Provider, outlined below:

9.1. Special protection 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. Special Protection Schemes (SPS) or System Integrity Protection Schemes (SIPS) are two mechanisms that can achieve such an outcome. 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’, whereby it provides coverage for a broad range of events based on observable metrics, such as frequency, voltage, power flow etc.

9.2. Frequency control services

9.2.1. Contingency FCAS

Contingency FCAS is a type of frequency control market ancillary service that helps to correct the frequency after a contingency event. Currently, this service is mainly provided by synchronous generation. 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.

9.2.2. Fast Frequency Response (FFR)

FFR services provide a type of frequency control service that can inject power or reduce consumption in response to changes in frequency in a timeframe that can be shorter than any market ancillary service.

18 Clause 5.20B.4(e) of the NER.
FFR services rely on the accurate measurement of frequency to inject or reduce active power. Frequency at generation connection points is measured differently, depending on whether the generation is synchronous or asynchronous.

Asynchronous plant measures frequency by other means that provide the potential for superior frequency response, but also present technical challenges associated with the accuracy of the measurement of frequency. Accuracy and false triggering of FFR devices is currently an issue when attempting to measure frequency and RoCoF very quickly after a major power system fault because there is a delay associated with the measurement of the frequency, a further communication delay between the measuring unit and the device providing FFR support, a further activation delay associated with the device and, finally, its active power ramp up/down time.

Nevertheless, existing technologies that can provide FFR services can be delivered within hundreds of milliseconds, which is considerably faster than the speed with which market ancillary services can be delivered. The ability to rapidly and accurately control active power within such a short timeframe (post-contingency) can have a significant impact on the RoCoF in the power system and the resulting magnitude of frequency excursions.

9.3. Network support agreements

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. Furthermore, if a generating unit is unable to withstand a high RoCoF, contracting to not generate at certain times would also reduce the level of inertia required to maintain the power system in a secure operating state.

10. THE METHODOLOGY

Clause 5.20.7(a) of the NER requires AEMO to take the following matters into account in determining the secure operating level of inertia:

1. the capabilities and expected response times provided by generating units providing market ancillary services (other than the regulating raise service or regulating lower service) in the inertia sub-network;
2. the maximum load shedding or generation shedding expected to occur on the occurrence of any credible contingency event affecting the inertia sub-network when the inertia sub-network is islanded;
3. additional inertia needed to account for the possibility of a reduction in inertia if the contingency event that occurs is the loss or unavailability of a synchronous generating unit, synchronous condenser or any other facility or service that is material in determining inertia requirements;
4. any constraints that could reasonably be applied to the inertia sub-network when islanded to achieve a secure operating state and any unserved energy that might result from the constraints; and
5. any other matters as AEMO considers appropriate.

Each of these matters is explained further below.

10.1. Fast FCAS

The capabilities and expected response times provided by market ancillary services (other than regulating raise services or regulating lower services) referred to in clause 5.20.7(a)(1), is a reference to Fast FCAS. As inertia is reduced in an inertia sub-network, a larger Fast FCAS response is required to maintain an Acceptable Frequency and keep the inertia sub-network in a satisfactory operating state.

Inertia by itself cannot arrest a fall in power system frequency entirely, or bring it back to be within the normal operating frequency band; it can only reduce the rate at which frequency changes. Fast FCAS, however, can arrest a decline in frequency.
Therefore, it is necessary to consider the availability of Fast FCAS in each inertia sub-network when determining the level of inertia required to keep the power system in a satisfactory operating state.

10.2. Maximum RoCoF
In an inertia sub-network, the RoCoF needs to be limited to provide sufficient time for the available Fast FCAS to maintain an Acceptable Frequency and keep the inertia sub-network in a satisfactory operating state. Limiting the RoCoF would provide sufficient time for the FFR services’ measuring devices to measure the frequency accurately and thereby avoid maloperation during transient spikes in the power system. Furthermore, specific RoCoF limits exist for reasons that include preventing sympathetic tripping of embedded generation via anti-islanding protection, preventing incorrect operation under-frequency load shedding schemes (UFLS) or over-frequency generator shedding schemes (OFGS), and exceeding RoCoF limits specified in performance standards. RoCoF must be maintained to a level that does not negatively impact power system security and reliability.

10.3. Maximum load or generation shedding
The maximum size of load shedding or generation shedding expected to occur on the occurrence of any credible contingency event affecting an islanded inertia sub-network is relevant because more inertia is required to manage a larger quantity of load shedding or generation shedding, with the same availability and response speed of FCAS.

Hence, the size of the inertia must be large enough to cover the largest load shedding or generation shedding likely to occur following a credible contingency event in an inertia sub-network.

10.4. Additional contingent inertia
Additional inertia where a credible contingency event results in the loss or unavailability of a synchronous generating unit, synchronous condensor or any other facility or service that is material in determining an inertia sub-network’s inertia requirements is also a relevant consideration.

This means an islanded inertia sub-network should be able to withstand a credible contingency event involving the disconnection of its largest generating unit or inertia network service. This could be either:
- the generating unit or inertia network service providing the largest amount of inertia; or
- the generating unit with the highest Minimum Operating Level, representing the largest generation loss following a contingency event.

10.5. Constraints
Constraint equations that could reasonably be invoked in an islanded inertia sub-network to achieve a secure operating state and any unserved energy that might result from the constraints referred to in clause 5.20.7(a)(4) could, for example, include one that operates to limit the RoCoF in an islanded inertia sub-network.

11. DETERMINING INERTIA REQUIREMENTS

11.1. General Approach
A two-stage approach is proposed as follows:

Stage 1
The first stage acts as a screening process to assess which inertia sub-networks are at risk of experiencing inertia shortfalls. At present, as the inertia sub-networks are the regions, this assessment will be carried out on a regional basis.\(^2\)

\(^2\) As specified in clause 11.100.2 of the NER. For future assessments, AEMO will need to review whether the inertia sub-networks need to be adjusted, as required by clause 5.20B.1 of the NER.
This assessment is based on simplified frequency trajectory assessments using SMM\(^21\). These assessments include assumptions about the delivery of Fast FCAS, and the relationship between inertia and the availability of Fast FCAS. These assumptions are described further in Section 11.2.

**Stage 2**

If the Stage 1 screening process indicates that the inertia in an inertia sub-networks is approaching the minimum threshold level of inertia, a second, more detailed assessment will be carried out.

These more detailed assessments require the use of a PSCAD™/EMTDC™model of relevant power systems, to allow determining minimum threshold level and secure operating level of inertia when an inertia sub-network becomes islanded.

It was not necessary to carry out a Stage 2 analysis to any region other than SA because AEMO did not identify a likelihood of inertia shortfalls in any regions except SA.

**11.2. Methodology to calculate inertia requirements**

AEMO will calculate the inertia requirements using the following methodology.

**11.2.1. Secure operating level of inertia**

This section outlines the methodology to calculate the secure operating level of inertia for an inertia sub-network.

**Step 1: Identification of relevant contingencies while islanded**

This step identifies the loss of the largest generating unit/generating system or load as a result of a credible contingency event or protected event while the inertia sub-network is islanded as follows:

- **Generation Contingency:** This is the generating unit/generating system whose loss produces the highest RoCoF in the inertia sub-network. The loss of a generating unit with the highest inertia will not necessarily result in the Generation Contingency\(^22\) that produces the highest RoCoF in the inertia sub-network.

- **Load Contingency:** Generally, the largest load in an inertia sub-network would be an industrial load, such as a smelter or potline, the size of which is largely uncontrollable via the central dispatch process.

It is assumed that a generating unit’s output may reduce to its Minimum Operating Level via the central dispatch process under conditions of low inertia, or where Fast FCAS is scarce or expensive, and the optimal dispatch solution is to reduce the size of the Generation Contingency to the lowest practical level.

**Step 2: Relationship between Fast FCAS requirement and Inertia**

A power system model of the inertia sub-network is used to assess the frequency trajectory following the contingency events identified in Step 1. This model is then used to establish the relationship between inertia levels and the required level of Fast FCAS response to maintain an Acceptable Frequency.

In developing this relationship, the following simplifications may be made:

- Generic governor models that represent the MASS requirements\(^23\) of Fast FCAS can be used to develop the inter-relationship between the inertia and Fast FCAS requirement.

- A simplified but appropriate wind farm fault ride-through (FRT) characteristic can be used.\(^24\)

- With appropriate justification, a simplified SMM of the power system can be used.\(^25\)

A power system with high inertia requires a lower amount of Fast FCAS to maintain an Acceptable Frequency while a power system with low inertia requires a larger amount of Fast FCAS. For a fixed

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\(^{21}\) A comparison between RMS type analysis and simplified frequency trajectory analysis using SMM is provided in Appendix A.

\(^{22}\) Refer to Appendix H for an example.


\(^{24}\) Further details are provided in Appendix E

\(^{25}\) Refer Table 5 of Appendix A for details.
system demand and contingency size, a typical inverse relationship between Fast FCAS requirement and inertia is shown in Figure 2.

**Figure 2  Relationship between Fast FCAS requirement and inertia**

![Graph showing the relationship between Fast FCAS requirement and inertia.](image)

**Step 3: Relationship between Fast FCAS availability and Inertia**

When a synchronous generating unit is dispatched to provide Fast FCAS\(^{26}\), it will invariably bring inertia to the power system. A high availability of Fast FCAS will correspond with high levels of inertia in the power system, which suggests a correlation between the availability of Fast FCAS, and system inertia\(^{27}\). Where Fast FCAS is provided by an ancillary services load\(^{28}\), however, it does not bring inertia to the power system.

The relationship between the amount of Fast FCAS that a generating unit/load brings to the power system and the inertia associated with it will depend on dispatch and can be highly variable and unpredictable. For the purpose of this analysis however, a linear relationship between Fast FCAS availability through generation and inertia is assumed. This characteristic can be determined for an inertia sub-network by assessing the Fast FCAS capability available within that inertia sub-network, and the associated inertia of generating units that provide that capability. An example of such a relationship is shown in Figure 3.\(^{29}\)

**Figure 3  Linear relationship assumed between Fast FCAS availability and inertia**

![Graph showing a linear relationship between Fast FCAS availability and inertia.](image)

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\(^{26}\) Fast Raise Service or Fast Lower Service.

\(^{27}\) Currently, the majority of fast raise services are provided by synchronous generating units. In future, this correlation might need to be reassessed.

\(^{28}\) Fast Raise Services.

\(^{29}\) Fast Raise Services provided by loads should been excluded when developing this relationship.
Step 4: Criteria for determining secure operating level of inertia

An operating condition where the amount of inertia in an inertia sub-network is consistent with both the availability of Fast FCAS, and the Fast FCAS required to maintain an Acceptable Frequency would indicate the secure operating level of inertia\(^{30}\).

The intersection of these two assumed characteristics – the requirement for Fast FCAS, and the availability of Fast FCAS, both as functions of inertia, is therefore used to determine the secure operating level of inertia for an inertia sub-network.

11.2.2. Minimum threshold level of inertia

AEMO operates the power system so that, to the extent practicable:

(a) it remains in a secure operating state; and

(b) following a contingency event, it can return to a secure operating state\(^ {31}\).

To be in a secure operating state, the power system must be in a satisfactory operating state and return to a satisfactory operating state following the occurrence of a credible contingency event or protected event\(^ {32}\).

Therefore, when considered through this prism, the minimum threshold level of inertia can be calculated as 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 minimum threshold level of inertia may require limits on interconnector flows while the inertia sub-network is at a credible risk of separation.

11.3. Relationship with System Strength Requirements

The Fault Levels Rule requires each region’s System Strength Service Provider (SSSP) to maintain the minimum three phase fault levels at each fault level node in each region (which are determined by AEMO) where the three phase fault level typically provided at each fault level node by dispatched generation is insufficient to maintain the power system in a secure operating state.

Therefore, a certain amount of inertia will invariably be available in each region as a result of the implementation of the Fault Levels Rule.

Considering that system strength services are required under all operating conditions, as compared with inertia network services, which are needed to cater for islanding conditions only, AEMO should take into account the typical Synchronous Machine dispatch pattern used to calculate minimum three phase fault levels at designated fault level nodes within an inertia sub-network when determining minimum threshold level of inertia and the secure operating level of inertia.

An assessment of the inertia levels as a result of the implementation of the Fault Levels Rule would assist to a large extent in meeting the inertia requirements as shown in Table 2. It is noted that in some circumstances, e.g. in NSW, the inertia delivered due to the implementation of Fault Level Rule would exceed that required due to the implementation of Inertia Rule.

11.4. Inertia Requirements for 2018

Having used the Methodology outlined in Section 11 to determine the inertia requirements for each region, Table 2 shows the inertia requirements for 2018.

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\(^{30}\) Refer Appendix A for an example.

\(^{31}\) See clause 4.2.6(a) and (b) of the NER.

\(^{32}\) See clause 4.2.4(a) of the NER.
Table 2  Inertia requirements for 2018

<table>
<thead>
<tr>
<th>Inertia sub-networks (Regions)</th>
<th>Inertia available through System Strength (MWs)</th>
<th>Minimum threshold level of inertia (MWs)</th>
<th>Secure operating level of inertia (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>11,950</td>
<td>12,800</td>
<td>16,000</td>
</tr>
<tr>
<td>New South Wales</td>
<td>18,100</td>
<td>10,000</td>
<td>12,500</td>
</tr>
<tr>
<td>Victoria</td>
<td>10,900</td>
<td>12,600</td>
<td>15,400</td>
</tr>
<tr>
<td>South Australia</td>
<td>4,900</td>
<td>4,400</td>
<td>6,000</td>
</tr>
<tr>
<td>Tasmania</td>
<td>2,000</td>
<td>3,200</td>
<td>3,800</td>
</tr>
</tbody>
</table>

Appendix A to E provide details of the calculations made for each region.

12. DETERMINING INERTIA SHORTFALLS

12.1. Typical Inertia

As part of the process of screening for inertia shortfalls, AEMO has considered the level of inertia typically provided in an inertia sub-network by reference to the dispatched inertia in that inertia sub-network during the previous year.

The range of values within one standard deviation of the mean dispatched inertia in an inertia sub-network during the last year are the levels of inertia typically provided in that inertia sub-network. Figure 4 shows an example inertia probability curve. The shaded area is the range of values within one standard deviation of the mean inertia.

For the purposes of calculating an inertia shortfall, the Typical Inertia is the Inertia value at one standard deviation below the mean.

Figure 4  Inertia probability distribution curve

This has been chosen because the standard deviation is an accepted statistical method to quantify the variation of a set of data values. Values within one standard deviation of the mean are not at the extremes; they are typical values of the data sets.

AEMO has chosen to use one standard deviation below the mean as this is considered a reasonable onerous scenario. The Typical Inertia for each region is provided in Appendix F.

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34 For Tasmania, the last three years were considered because of the reasons highlighted in Section E.1.
12.2. Inertia shortfall calculation

AEMO calculates the *inertia shortfall* for each *inertia sub-network* as follows:

\[
\text{Inertia shortfall} = \text{Typical Inertia} - \text{secure operating level of inertia}
\]

12.3. Interconnection with other inertia sub-networks

In determining whether there are any *inertia shortfalls* in any *inertia sub-network*, clause 5.20B.3(b)(2) of the NER requires AEMO to consider the likelihood of an *inertia sub-network* becoming *islanded*.

AEMO has carried out this analysis and the results are depicted in Table 3:

<table>
<thead>
<tr>
<th>Inertia Sub-Network</th>
<th>Interconnections</th>
<th>Likelihood of Islanding</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>One 330 kV AC double-circuit to NSW. One DC link to NSW.</td>
<td>Likely</td>
</tr>
<tr>
<td>New South Wales</td>
<td>One 220 kV and three 330 kV AC connections to Victoria. One 330 kV AC double-circuit and one DC link connection to Queensland.</td>
<td>Unlikely</td>
</tr>
<tr>
<td>Victoria</td>
<td>One 220 kV and three 330 kV AC connections to NSW. One double-circuit 275 kV AC and one DC link connection to SA. One DC link to Tasmania.</td>
<td>Unlikely(^{27})</td>
</tr>
<tr>
<td>Tasmania</td>
<td>One DC link to Victoria.</td>
<td>Likely</td>
</tr>
<tr>
<td>South Australia</td>
<td>One 275 kV AC double-circuit to Victoria. One DC link to Victoria.</td>
<td>Likely</td>
</tr>
</tbody>
</table>

13. INERTIA SHORTFALLS

13.1. Inertia Shortfalls for 2018

Using the methodology for calculating the *inertia requirements* outlined in Section 11 and the one for calculating *inertia shortfalls* in Section 12, Table 4 shows the *inertia shortfalls* for 2018. Further details of the rationale for the results for each *inertia sub-network* can be found in Appendices A to E.

<table>
<thead>
<tr>
<th>Inertia sub-networks</th>
<th>Typical level of inertia (MWs)</th>
<th>Minimum threshold level of inertia (MWs)</th>
<th>Secure operating level of inertia (MWs)</th>
<th>Inertia shortfalls (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>26,800</td>
<td>12,800</td>
<td>16,000</td>
<td>None</td>
</tr>
<tr>
<td>New South Wales</td>
<td>32,600</td>
<td>10,000</td>
<td>12,500</td>
<td>None</td>
</tr>
<tr>
<td>Victoria</td>
<td>17,100</td>
<td>12,600</td>
<td>15,400</td>
<td>None</td>
</tr>
<tr>
<td>South Australia</td>
<td>6,200</td>
<td>4,400</td>
<td>6,000</td>
<td>None</td>
</tr>
<tr>
<td>Tasmania</td>
<td>6,000</td>
<td>3,200</td>
<td>3,800</td>
<td>None</td>
</tr>
</tbody>
</table>

13.2. Consideration of Inertia Support Activities

No *Inertia Support Provider* requested AEMO’s approval of any *inertia support activities* under clause 5.20B.5(a) of the NER.

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\(^{25}\) Murraylink and Directlink are DC *interconnectors*, therefore they do not provide *synchronous connection* to other regions.

\(^{26}\) The Victoria to NSW *interconnector* also has two 132 kV *connections* that don’t form part of the main *transmission* backbone.

\(^{27}\) Victoria was *islanded* on 16 Jan 2007 as a consequence of multiple *transmission line* trips in quick succession during a *bushfire*. Since then, AEMO considers a repetition of such an event unlikely because AEMO has commissioned emergency control scheme which will reduce the risk of islanding significantly.
APPENDIX A. INERTIA REQUIREMENTS FOR QUEENSLAND

Appendix A shows AEMO’s calculations of the inertia requirements for Queensland using the methodology outlined in Section 11.

A.1 Secure operating level of inertia

Step 1: Identification of relevant contingencies while islanded

While Queensland is an island the following are the largest credible contingency events (currently there are no protected events):

- **Generation Contingency**: Kogan Creek has the largest generating unit, while Swanbank E has the largest inertia generating unit. Both can reduce to their respective Minimum Operating Levels. Considering the size of the largest loss of generation and inertia, Kogan Creek at its Minimum Operating Level was the Generation Contingency utilised.
- **Load Contingency**: The largest loss of load following a contingency event would be loss of one Boyne Island Smelter potline.

Step 2: Relationship between Fast FCAS and inertia

Queensland has a large number of thermal power stations. Figure 5 shows the inertia duration curve for 2017. The lowest inertia dispatch that occurred on 3 October 2017 at 2330 hrs is used for power system analysis.

**Figure 5  Queensland inertia duration curve**

The base case developed was integrated with generic governor models, which simulated a simplified governor response that closely aligned with the MASS requirements for Fast FCAS. One such example is shown in Figure 6.
Comparison between PSS®E and SMM

After integrating governor models into the base case, the base case was tested for various operating conditions. A comparison between the results achieved using PSS®E and a SMM was carried out.

The insignificant difference in Fast FCAS requirements between two simulation platforms, as shown in Table 5, suggests that an SMM can be used to calculate the inertia requirements.

Table 5  Comparison between PSS®E and Single Mass Model

<table>
<thead>
<tr>
<th>System conditions</th>
<th>RMS model</th>
<th>SMM</th>
</tr>
</thead>
<tbody>
<tr>
<td>System conditions</td>
<td>RMS model</td>
<td>SMM</td>
</tr>
<tr>
<td>Sr No</td>
<td>Inertia (MWs)</td>
<td>Demand (MW)</td>
</tr>
<tr>
<td>1</td>
<td>17116</td>
<td>4518</td>
</tr>
<tr>
<td>2</td>
<td>18246</td>
<td>4693</td>
</tr>
<tr>
<td>3</td>
<td>20343</td>
<td>5082</td>
</tr>
<tr>
<td>4</td>
<td>21391</td>
<td>5082</td>
</tr>
</tbody>
</table>

Figure 7 shows the relationship between the inertia and amount of Fast FCAS required to maintain an Acceptable Frequency\[38\].

\[38\] POE 99 demand of the previous year and 1.5% load relief have been used in the analysis.
Figure 7  Relationship between Fast FCAS and inertia

Step 3: Inertia available through Fast FCAS
Queensland has 1,206 MW of fast raise services and 688 MW of fast lower services available from synchronous generating units\(^\text{39}\). Dispatching 688 MW of fast lower services and 1,206 MW of fast raise services would add 21,000 MWs\(^\text{40}\) and 24,000 MWs\(^\text{41}\) of inertia, respectively, considering the combined inertia of all Fast FCAS providers in Queensland.

The associated inertia for different levels of Fast FCAS in Queensland was calculated, and is displayed in Figure 8.

Step 4: Secure operating level of inertia
Figure 8 shows the relationship between the inertia required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. It also shows the inertia available by dispatching fast raise services. The intersection of the two curves indicates the secure operating level of inertia for the largest Generation Contingency or Load Contingency, as applicable.

Therefore, the secure operating level of inertia is 16,000 MWs\(^\text{42}\). This level of inertia would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

\(^{39}\) As detailed in AEMO’s NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list published as at 11 April 2018 was used to complete the analysis to publish the inertia requirements by 30 June 2018.

\(^{40}\) Rounded to the nearest 100 MWs.

\(^{41}\) Rounded to the nearest 100 MWs.

\(^{42}\) Rounded to the nearest 100 MWs.
A.2 Minimum threshold level of inertia

The minimum threshold level of inertia is determined by subtracting the largest inertia generating unit in Queensland from the secure level of inertia just determined.

The largest inertia generating unit in Queensland is Swanbank E with 3,225 MWs of inertia. Therefore,

\[
\text{Minimum threshold level of inertia} = 16,000 \text{ MWs} - 3,225 \text{ MWs} = 12,775 \text{ MWs}
\]

The minimum threshold level of inertia for Queensland is 12,800 MWs\(^43\).

\(^43\) Rounded to the nearest 100 MWs.
APPENDIX B. INERTIA REQUIREMENTS FOR NEW SOUTH WALES

Appendix B shows AEMO’s calculations of the inertia requirements for NSW using the methodology outlined in Section 11.

B.1 Secure operating level of inertia

Step 1: Identification of Relevant Contingencies while Islanded

While NSW is an island the following are the largest credible contingency events (currently there are no protected events):

- **Generation Contingency**: Bayswater’s generating units have the highest Minimum Operating Level (330 MW) of any generating unit, but they have a slightly lower inertia than Eraring’s generating units (2483 MWs as opposed to 2516 MWs), however, Eraring generating units have a significantly lower Minimum Operating Level (210 MW) so the small inertia difference is not considered to be material. Therefore, a Bayswater generating unit at its Minimum Operating Level was the Generation Contingency utilised.

- **Load Contingency**: The largest loss of load following a credible contingency event is the loss of one Tomago potline.

Step 2: Relationship between Fast FCAS and Inertia

Studies for Queensland demonstrated that an SMM can be used to establish a relationship between the level of inertia and the amount of Fast FCAS required to maintain an Acceptable Frequency in an islanded region. Figure 9 shows this relationship for NSW. 44

![Figure 9: Relationship between Fast FCAS and inertia](image)

**Step 3: Inertia available through Fast FCAS**

NSW has 1,674 MW of fast raise services that can be provided by synchronous generating units and loads (842 MW by synchronous generating units and 832 MW by loads). It also has a maximum of 1,184 MW of fast lower services that can be provided by synchronous generating units. 45 When a synchronous generating unit is dispatched to provide Fast FCAS it will invariably bring inertia to the power system. For

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44 This analysis assumed a contingency as determined in Step 1, a POE 99 demand of the previous year and 1.5% load relief.

example, dispatching 1,674 MW of fast raise services or 1,184 MW of fast lower services would add 45,000 MWs of inertia to the region.

The inertia for different levels of Fast FCAS in NSW was calculated, and this is displayed in Figure 10.

**Step 4: Secure Operating Level of Inertia**

Figure 10 shows curves illustrating the relationship between inertia and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. It also shows two linearized relationships between Fast FCAS and inertia available by dispatching Fast FCAS that are relevant for the Generation Contingency and Load Contingency. The intersection of each curve with its relevant line indicates the secure operating level of inertia for the largest Generation Contingency or Load Contingency, as applicable.

The highest secure operating level of inertia is 12,500 MWs. This level of inertia would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

**Figure 10  Relationship between Fast FCAS and Inertia**

![Graph showing the relationship between Fast FCAS and Inertia](image)

**B.2 Minimum threshold level of inertia**

The generating unit with the highest inertia in NSW is any Eraring generating unit with 2,516 MWs of inertia. Therefore:

Minimum threshold level of inertia = 12,500 MWs − 2,516 MWs = 9,984 MWs

The minimum threshold level of inertia for NSW is 10,000 MWs.

---

46 Rounded to the nearest 100 MWs
47 Rounded to the nearest 100 MWs.
48 Rounded to the nearest 100 MWs.
APPENDIX C. INERTIA REQUIREMENTS FOR VICTORIA

Appendix C shows AEMO’s calculations of the inertia requirements for Victoria using the methodology outlined in Section 11.

C.1 Secure operating level of inertia

Step 1: Identification of Relevant Contingencies while Islanded

While Victoria is an island the following are the largest credible contingency events (currently there are no protected events):

- **Generation Contingency**: Loy Yang A generating unit 2 has the highest inertia and the equal highest Minimum Operating Level (300 MW). Loy Yang A generating unit 2 at its Minimum Operating Level was one Generation Contingency used.

- **Load Contingency**: The largest loss of load following a contingency event in Victoria is loss of one APD potline.

Step 2: Relationship between Fast FCAS and Inertia

Studies for Queensland demonstrated that a SMM can be used to establish a relationship between the level of inertia and the amount of Fast FCAS required to maintain an Acceptable Frequency in an islanded region. Figure 11 shows this relationship for Victoria.

![Figure 11](image)

**Figure 11** Relationship between Fast FCAS and inertia

Step 3: Inertia available through Fast FCAS

Victoria has a maximum of 1,031 MW of fast raise services that can be provided by synchronous generating units and loads (471 MW by synchronous generating units and 560 MW by loads). It also has a maximum of 763 MW of fast lower services that can be provided by synchronous generating units. When a synchronous generating unit is dispatched to provide Fast FCAS it will invariably bring inertia to

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49 POE 99 demand of the previous year and 1.5% load relief have been used in the analysis.
50 As detailed in AEMO’s NEM Registration and Exemption List. Available at: [http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists](http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists). The list published as at 11 April 2018 was used to complete the analysis to publish the inertia requirements by 30 June 2018.
the power system. For example, dispatching 1,031 MW of fast raise services or 763 MW of fast lower services would add 28,000 MWs\(^{51}\) of inertia to Victoria.

At 300 MW output, Loy Yang A and Loy Yang B cannot provide fast lower services. For the largest Load Contingency, trip of one APD potline, it is assumed that not all fast lower services need to be available and, therefore, the largest Generation Contingency is left at 300 MW. In this instance, the fast lower services and inertia of generating units that cannot provide fast lower services at 300 MW are excluded from the calculation of the relationship between Fast FCAS and inertia available by dispatching Fast FCAS. The relationship is derived by assuming a linear relationship from an adjusted maximum of 283 MW of fast lower services and the attendant 15,300 MWs of inertia, back to the origin.

Figure 12 includes traces for both fast lower services relationships and one for the fast raise services relationship.

**Step 4: Secure Operating Level of Inertia**

Figure 12 illustrates the relationship between inertia and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency, as determined in step 1. The intersection of each curve with its relevant line indicates the secure operating level of inertia for the largest Generation Contingency or Load Contingency, as applicable.

Therefore, the secure operating level of inertia is 15,400 MWs\(^{52}\). This level of inertia would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

**Figure 12  Relationship between Fast FCAS and inertia**

![Graph showing the relationship between Fast FCAS and inertia](image)

**C.2 Minimum threshold level of inertia**

The generating unit with the highest inertia in Victoria is Loy Yang A generating unit 2 with 2,752 MWs of inertia. Therefore:

\[
\text{Minimum threshold level of inertia} = 15,400 \text{ MWs} - 2,752 \text{ MWs} = 12,648 \text{ MWs}
\]

The minimum threshold level of inertia for Victoria is 12,600 MWs\(^{53}\).

---

51 Rounded to the nearest 100 MWs
52 Rounded to the nearest 100 MWs.
53 Rounded to the nearest 100 MWs.
APPENDIX D. INERTIA REQUIREMENTS FOR SOUTH AUSTRALIA

For the purpose of calculating the inertia requirements for SA, AEMO used a PSCAD model of the SA power system. This detailed model represents the accurate FRT behaviour of wind farms, which is often important for calculating inertia requirements in a region where asynchronous generation is high compared to synchronous generation.

Appendix D shows AEMO’s calculations of the inertia requirements for SA using the methodology outlined in Section 11.

D.1 Secure operating level of inertia

Step 1: Identification of relevant contingencies while islanded

While SA is an island the following are the largest contingencies:

- **Generation Contingency**: Lake Bonney Wind Farm is the largest generating system in SA, but it does not provide inertia. Moreover, generation from this generating unit can be reduced while still meeting regional demand from other generating units. Pelican Point has the largest generating unit with the highest inertia. Along with inertia, it also contributes to system strength. Considering the size of the loss of generation and inertia, Pelican Point Gas Turbine unit at its Minimum Operating Level was the Generation Contingency utilised.

- **Load Contingency**: The largest loss of load following a contingency event would be the Olympic Dam load.

SA has a total 1800 MW of asynchronous generation. The majority of this is electrically close to each other. A transmission fault in SA would mean that the majority of its generation would go through its FRT mode, withdrawing the majority of the generation temporarily. This temporary loss of generation further impacts the frequency change.

Step 2: Relationship between Fast FCAS and inertia

Figure 13 shows the relationship between the inertia and amount of Fast FCAS required to maintain an Acceptable Frequency. Only the Generation Contingency is shown as this is more onerous than load contingency. This relationship is achieved using PSCAD model for SA.

Step 3: Inertia available through Fast FCAS

SA has 212 MW of fast raise services and fast lower services. Out of these, 63 MW is available by the Hornsdale Power Reserve. When a synchronous generating unit is dispatched to provide Fast FCAS it will invariably bring inertia to the power system. However, when Hornsdale Power Reserve is dispatched to provide Fast FCAS it will not add inertia to the power system. For SA, dispatching 212 MW of Fast FCAS would add 13,200 MWs of inertia considering the combined inertia of all Fast FCAS providers in SA.

Step 4: Secure Operating Level of Inertia

Figure 14 illustrates the relationship between inertia and Fast FCAS required to maintain an Acceptable Frequency for the largest Generation Contingency, as determined in step 1. It also shows a linearized

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55 Generation information page. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information. The list published as at 11 April 2018 was used to complete the analysis to publish the inertia requirements by 30 June 2018


57 As detailed in AEMO’s NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list published as at 11 April 2018 was used to complete the analysis to publish the inertia requirements by 30 June 2018.

58 Rounded to the nearest 100 MWs.
relationship between Fast FCAS and inertia available by dispatching Fast FCAS. The intersection of curves indicates the secure operating level of inertia for the largest Generation Contingency.

Therefore, the secure operating level of inertia is 6,000 MWs. This level of inertia would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

**Figure 13  Relationship between Fast FCAS and inertia**

![Inertia and FCAS](image1)

**Figure 14  Relationship between Fast FCAS and inertia**

![Inertia and FCAS](image2)

**D.2  Minimum threshold level of inertia**

The generating unit with the highest inertia in SA is Pelican Point GT generating unit with 1,625 MWs of inertia. Therefore:

Minimum threshold level of inertia = 6,000 MWs − 1,625 MWs = 4,375 MWs

The minimum threshold level of inertia for SA is 4,400 MWs.\(^6\)

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\(^5\) Rounded to the nearest 100 MWs.

\(^6\) Rounded to the nearest 100 MWs.
APPENDIX E. INERTIA REQUIREMENTS FOR TASMANIA

At present, the vast majority of the inertia available in Tasmania resides within transmission-connected synchronous generating units. While it is recognised that there is a growing number of small embedded generating systems still using traditional synchronous machines, such as mini-hydro and small-frame gas turbines, the size of these generating units has typically been less than 5 to 7 MW. As a result, they provide a relatively minor contribution to inertia.

E.1 Operational differences between Tasmania and mainland regions

Tasmania is connected to the mainland via the Basslink HVDC interconnector. Basslink provides an asynchronous connection between the mainland and Tasmania. There are a number of operational measures in place for Tasmania that are different to any other region as a result of this arrangement.

E.1.1 Basslink interconnector

Loss of the Basslink interconnector is managed via the use of the Frequency Control System Protection Scheme (FCSPS). These schemes ensure that the frequency operating standard will be maintained if the interconnector trips and Tasmania forms an island by rapidly disconnecting armed load or generation.

For the purpose of calculating the inertia requirements for Tasmania, the loss of Basslink is actively managed through central dispatch.

E.1.2 Generating units

The majority of generating units in Tasmania are hydro with very low Minimum Operating Levels. This is different to the mainland, where Minimum Operating Levels are an important factor in determining contingency events that underlie inertia requirements.

At any given instant, to meet the supply-demand balance, sufficient generating units are required to be online at a sufficient operating levels to meet demand. This results in a wide possible range of contingency events that could be considered.

Therefore, Tasmania’s hydro generating units will not be reduced to their Minimum Operating Levels for the purpose of calculating the inertia requirements.

E.1.3 Wind generation fault ride-through

Tasmania currently has around 308 MW of wind generation. During a fault, if the voltage at the terminal of these wind farms is below a specified threshold, these wind farms will enter FRT mode and temporarily reduce their generation. This temporary reduction in the wind generation increases the RoCoF of the power system. The transient energy deficit introduced by FRT characteristics can persist for up to 1 second, albeit that active power recovery commences as soon as voltage rises back above the FRT threshold level. The maximum rate of recovery is a function of the network strength at the wind farm connection point. On the occurrence of a transmission fault in Tasmania, it is reasonable to assume that all wind generation will enter into FRT mode. Therefore, the effect of this temporary reduction on RoCoF is considered when calculating inertia requirements for Tasmania.

E.1.4 RoCoF constraint

Since 2013, AEMO has used RoCoF constraint equations in Tasmania that maintain frequency transients within the technical envelope of the Tasmanian power system during periods of high power in-feed from asynchronous generation sources.

The maximum RoCoF must be limited to a value that does not result in the operation of anti-islanding protection (relevant to both transmission-connected and embedded generation connected to the distribution network) and ensures that all synchronous generating units remain transiently stable. A limit of ±3 Hz/s RoCoF with a filter and averaging period of approximately 100 ms after fault clearance is applied for any credible contingency event. Described as a general limit having a positive and negative slope, it is intended to apply to all types of credible contingency events affecting both generation and load.
In addition, TasNetworks has been applying a limit of -1.18 Hz/s when frequency passes through 49.0 Hz. A safety margin is applied that reduces the allowable RoCoF to 1.076 Hz/s for the purposes of central dispatch. This is to prevent operation of under-frequency load shedding relays that have been made sensitive to RoCoF.

The underlying principle is that an Acceptable Frequency should be maintained for credible contingency events expected to be managed by the dispatch of FCAS in combination with inertia, inertia network services or both.

Therefore, these RoCoF limits will be considered for the purpose of calculating the inertia requirements.

**E.1.5 Load or generation shedding**

Clause 5.20.7(a)(2) of the NER requires AEMO to consider “the maximum load shedding or generation shedding expected to occur on the occurrence of any credible contingency event affecting the inertia sub-network when the inertia sub-network is islanded”.

Tasmania has SPSs that disconnect generation or load to reduce the imbalance between supply and demand following a credible contingency event. Key SPSs that influence the calculation of inertia requirements are outlined in Table 6.

<table>
<thead>
<tr>
<th>Table 6</th>
<th>Tasmania power system – credible contingency event and special protection schemes</th>
</tr>
</thead>
<tbody>
<tr>
<td>No</td>
<td>Description of contingency event</td>
</tr>
<tr>
<td>1</td>
<td>Loss of Basslink interconnector</td>
</tr>
<tr>
<td>2</td>
<td>Loss of Tamar Valley Power Station</td>
</tr>
</tbody>
</table>

Therefore, the impact of these SPSs on the reduction of the size of contingency events will be considered for the purpose of calculating the inertia requirements.

**E.1.6 Adaptive under-frequency load shedding scheme 2 (AUFLS2)**

The purpose of the scheme is to provide additional fast raise services in Tasmania by shedding load in response to a fall in frequency. AUFLS2 continuously calculates the RoCoF. When the trigger frequency is reached, it uses the calculated RoCoF to trip a variable number of load blocks. This scheme provides significant fast raise services but because it is load based, does so without the addition of any inertia to the power system. The amount of the service available through this scheme depends on the amount of available industrial load.

Therefore, the effect of AUFLS2 in reducing the inertia requirements will be considered for the purpose of calculating the inertia requirements.

**E.1.7 Lower FCAS reduction scheme**

The lower FCAS reduction scheme is designed to trip designated generation when the power system frequency rises above a frequency threshold between 51 Hz – 52 Hz\(^{61}\). This means a number of hydro generating units may trip, by design, for high frequency conditions in Tasmania following single credible contingency events, such as loss of load at Bell Bay Aluminium.

Therefore, the effect of lower FCAS reduction scheme in reducing the inertia requirements will be considered for the purpose of calculating the inertia requirements.

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\(^{61}\) The frequency operating band for a ‘generation event’ or a ‘load event’ is 48 to 52 Hz for Tasmania island operation. See Table A.2.2 of the frequency operating standards.
E.1.8 Water storage

Tasmania has a large number of hydro generating units whose operation relies not only on market conditions, but also on water storage levels. Often, the volume of water storage drives the amount of energy that Tasmania is likely to export to the mainland. This influences the dispatch of generating units in Tasmania and thereby the inertia available in the region.

Therefore, in determining the Typical Inertia in Tasmania, it would be prudent to look at more than one year’s worth of historical data.

E.2 Inertia Requirements

Appendix E.2 shows AEMO’s calculations of the inertia requirements for Tasmania using the methodology outlined in Section 11 and considering the operational differences between Tasmania and the mainland regions outlined in Section E.1.

E.2.1 Frequency operating standard

The following should be noted when applying the frequency operating standard in Tasmania:

- The disconnection of Tasmania from the mainland is treated as a ‘network event’, as this is always a credible contingency, and the ‘interconnected system’ provisions continue to apply.
- The ‘islanded operation’ provisions only apply where an island has formed wholly within Tasmania, for example, an isolated west coast network.
- Credible contingency events must be managed within the range 48.0 to 52.0 Hz.

E.2.2 Secure operating level of inertia

Step 1: Identification of Relevant Contingencies while Islanded

While Tasmania is an island the following are the largest credible contingency events (currently there are no protected events):

- **Generation Contingency**: Considering the size of the largest loss of generation and inertia, Gordon unit Generation Contingency is utilised.
- **Load Contingency**: The largest loss of load following a contingency event in Tasmania would be the Rio Tinto potline.

Step 2: Relationship between Fast FCAS and Inertia

While Tasmania is an island, it is important to consider the effect of the FRT of wind farms on RoCoF and thereby inertia requirements to limit RoCoF. Figure 15 shows the FRT behaviour of those wind farms. The shaded area shows an energy deficit caused by the FRT characteristic of wind farms. This energy deficit will depend on the fault location, residual voltage and voltage recovery at the wind farm terminals.

The FRT characteristic shown in Figure 16 has been utilised for the purpose of calculating the inertia requirements.

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62 See Table A.2.1 of the frequency operating standard.
63 Table A.2.2 of the frequency operating standard.
64 Table A.2.2 of the frequency operating standard.
65 Electrical island in the context of inertia requirements methodology.
66 Consideration has been given to the exiting SPSs in the region.
Figure 15  Wind generation fault ride through in Tasmania

Figure 16  Wind farm FRT characteristic

Figure 17  Relationship between Fast FCAS and inertia

Figure 17 shows the relationship between the inertia required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency and Load Contingency in Tasmania. The effect of FRT behaviour of wind farms is also shown in Figure 17.
Step 3: Inertia available through Fast FCAS

Tasmania has 388 MW of fast raise services and 669 MW of fast lower services provided by synchronous generating units. When a synchronous generating unit is dispatched to provide Fast FCAS it will invariably bring inertia to the power system. For example, dispatching 388 MW of fast lower services and 669 MW of fast raise services would add 8,900 MWs and 11,200 MWs of inertia respectively to Tasmania.

The inertia for different levels of Fast FCAS in Tasmania was calculated, and is displayed in Figure 18.

Step 4: Secure operating level of Inertia

When calculating the secure operating level of inertia for Tasmania, the following is considered:

- RoCoF constraints: The maximum RoCoF must be limited to ±3 Hz/s with an averaging period of approximately 100 milliseconds after fault clearance. Moreover, it should be limited to 1.079 Hz/s when frequency passes through 49.0 Hz.
- AUFLS2: This scheme is designed to provide additional Fast FCAS by shedding load in response to a fall in frequency. The Fast FCAS contribution of 65 MW is considered.

Figure 18 shows the relationship between inertia required and Fast FCAS to maintain an Acceptable Frequency for the largest Generation Contingency, as determined in step 1. It also shows the inertia available by dispatching fast raise services and effect of AUFLS2 in providing additional Fast FCAS. It shows the RoCoF limit that is currently being applied to the region. The intersection of the two curves indicates the secure operating level of inertia. This level of inertia also meets RoCoF constraints for Tasmania.

The secure operating level of inertia would be 3,800 MWs. This level of inertia would maintain an Acceptable Frequency for the largest Generation Contingency or Load Contingency.

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67 As detailed in AEMO’s NEM Registration and Exemption List. Available at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Participant-information/Current-participants/Current-registration-and-exemption-lists. The list published as at 11 April 2018 was used to complete the analysis to publish the inertia requirements by 30 June 2018.
68 Rounded to the nearest 100 MWs.
69 Rounded to the nearest 10 MWs.
70 Average Fast FCAS provide by AUFLS2 between from the day it was commissioned and 1 June 2018.
71 Rounded to the nearest 100 MWs.
72 Load contingency has lower impact than generator contingency therefore it is not shown in Figure 18.
E.3 Minimum threshold level of inertia

The largest *inertia generating unit* in Tasmania is Gordon with 625 MWs of *inertia*. Therefore:

\[
\text{Minimum threshold level of inertia} = 3,800 \text{ MWs} - 625 \text{ MWs} = 3,175 \text{ MWs}
\]

The *minimum threshold level of inertia* for Tasmania is 3,200 MWs\(^2\).

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\(^2\) Rounded to the nearest 100 MWs.
APPENDIX F.  TYPICAL INERTIA FOR INERTIA SUB-NETWORKS

For the purpose of calculating the Typical Inertia, AEMO used inertia provided in mainland inertia sub-networks during the previous year, and for the Tasmanian inertia sub-network the previous three years.

Ideally, the inertia data used to calculate an inertia sub-network’s Typical Inertia should come from periods that are relevant to the inertia requirements, such as when an inertia sub-network is islanded or at a credible risk of islanding. In practice, however, such data sets are either very small or non-existent for mainland regions due to their rarity. Therefore, AEMO has used inertia data from the entire previous year to work out the Typical Inertia for each inertia sub-network other than Tasmania.

These Typical Inertia values will be conservative as the inertia in an inertia sub-network is likely to be higher when an inertia sub-network is at a credible risk of islanding. This is due to synchronous generating units being incentivised to come online by FCAS constraints, or the environmental conditions that increase the risk of islanding (e.g. bushfires) being correlated with high demand and, therefore, high synchronous generating unit dispatch and inertia. For example, Victoria has only islanded once since the NEM commenced in 1998, and this was during a high demand/inertia period instigated by bushfires.

Tasmania is always a synchronous island as it has no AC connections to other regions. Therefore, all historical inertia data is relevant to the calculation of Tasmania’s Typical Inertia. The generation dispatch, and, hence, the inertia in Tasmania is influenced by the water storage level of its hydro-electric schemes. Therefore, the previous year’s data does not reflect the typical level of inertia provided in Tasmania. Therefore, AEMO has calculated Typical Inertia values for each of the last three years and used the average of these for its inertia shortfall assessment.

Figure 19 to Figure 25 show the Typical Inertia available in each of the inertia sub-networks. Table 7 shows Typical Inertia available in each region.

<table>
<thead>
<tr>
<th>Region</th>
<th>Typical Inertia level (MWs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Queensland</td>
<td>26,800</td>
</tr>
<tr>
<td>New South Wales</td>
<td>32,600</td>
</tr>
<tr>
<td>Victoria</td>
<td>17,100</td>
</tr>
<tr>
<td>South Australia</td>
<td>6,200</td>
</tr>
<tr>
<td>Tasmania</td>
<td>6,000</td>
</tr>
</tbody>
</table>

24 Tasmania is always a synchronous island. Basslink is a DC connection, therefore, it does not form a synchronous connection to Victoria.
Figure 19  Typical inertia - Queensland

Figure 20  Typical inertia – New South Wales

Figure 21  Typical inertia – Victoria
Figure 22  Typical inertia – South Australia

Figure 23  Typical inertia – Tasmania 2015

Figure 24  Typical inertia – Tasmania 2016
Figure 25  Typical inertia – Tasmania 2017
APPENDIX G. IMPACT OF FAST FREQUENCY RESPONSE

Appendix G examines the relationship between inertia support activities such as FFR and the inertia requirements.

G.1 Introduction

The specification of Fast FCAS in the NEM requires full delivery within six seconds. A key assumption in previous calculations of inertia requirements is that the full 6 second time period is required for complete delivery of a Fast FCAS response.

If however a FCAS response can be fully delivered in less than 6 seconds, this allows the Frequency Standards to be met with dispatch of less inertia, for a given contingency size. This suggests 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 inertia levels are reduced due to faster delivery of an FCAS response, this high RoCoF could itself be a limiting factor for operation of the power system in a secure operating state.

As described in Section 9.2, 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.

G.2 Fast Frequency Response (FFR) model

During this analysis an FFR model with the following settings has been used:

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

Measurement time delay of 150ms. These settings result in full activation of the response by the time frequency reaches 49 or 51 Hz.

G.3 Analysis

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

- Fast FCAS delivered as per the requirements set out in MASS;
- FFR that represents the FFR model explained in previous Appendix G2.

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 26 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 26 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 27 shows the relationship between FFR and contingency size and demonstrates that FFR is more effective for larger contingencies.

---

75 Some measurement units can accurately measure signal value quicker than 150ms.
Figure 28 shows the relationship between FFR and RoCoF. The horizontal axis shows the percentage of FFR from the total FCAS dispatched. Whilst a higher percentage of FFR can achieve a reduction in the inertia requirements as shown in Figure 26, it will also increase the RoCoF as shown in Figure 28.

Figure 28 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.

**Figure 26  Relationship between FFR and Inertia**

**Figure 27  Relationship between FFR and Contingency**

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*, i.e. a certain level of *inertia* provided by Synchronous Machines will still be required.
APPENDIX H. IDENTIFYING GENERATION CONTINGENCY

Appendix H provides an example on how to identify the Generation Contingency in an islanded 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.

The RoCoF resulting from a contingency event is a good indicator of the relationship between these two outcomes.

Table 8 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 MWs and 4100 MW, respectively.

Table 8  Generation and inertia outcomes

<table>
<thead>
<tr>
<th>Contingency event No</th>
<th>Contingent inertia (MWs)</th>
<th>Loss of generation (MW)</th>
<th>RoCoF (Hz/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>2500</td>
<td>150</td>
<td>0.30</td>
</tr>
<tr>
<td>2</td>
<td>3200</td>
<td>150</td>
<td>0.32</td>
</tr>
<tr>
<td>3</td>
<td>500</td>
<td>175</td>
<td>0.30</td>
</tr>
<tr>
<td>4</td>
<td>3200</td>
<td>100</td>
<td>0.21</td>
</tr>
</tbody>
</table>

Table 8 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.