AEMC

REVIEW

Australian Energy Market Commission

INTERIM REPORT

System Security Market Frameworks Review

15 December 2016

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

Executive Summary

The electricity industry in Australia is undergoing a fundamental transformation. Driven by technological development and climate change policies, the National Electricity Market (NEM) is experiencing a significant shift away from conventional generators, powered by coal and gas, and towards new technologies, such as wind farms and solar panels.

Due to their different technical characteristics, the widespread deployment of these new technologies has the potential to have major impacts on the operation of the power system. The Australian Energy Market Commission (AEMC or Commission) is consequently reviewing aspects of NEM system security, working closely with the Australian Energy Market Operator (AEMO), to consider, develop and implement changes to market frameworks to allow the continued uptake of these new generating technologies while maintaining the security of the system.

This is the Commission's interim report to the COAG Energy Council on the Commission's System Security Market Frameworks Review (the Review) which was initiated by the Commission in July 2016. This report sets out some of the key aspects of system security being considered and some of the preliminary findings of the Commission.

This report also sets out the options the Commission will continue to develop in conjunction with stakeholders for new market frameworks that will facilitate the transition of the market and the entry of new technologies and new participants in a manner that delivers secure energy at the best price for consumers.

New market frameworks need careful design to limit costs over the longer term while enabling innovation and sufficient investment for new service provision to be effective in maintaining security as the market transitions.

The Commission seeks stakeholder views on the preliminary findings and potential changes to market arrangements outlined in this interim report.

This report does not address matters related to the black system event that occurred in the South Australian region in September 2016. The COAG Energy Council has directed the AEMC to undertake a separate review of the events in South Australia, building on and following, the completion of the technical work currently being conducted by AEMO and any other work undertaken by the Australian Energy Regulator in relation to that event.

Challenges in managing system security

In order to allow a reliable supply of electricity to be provided to customers, the power system must be operated in a secure manner. The system is secure when technical parameters such as power flows, voltage, and frequency are maintained within defined limits.

Maintaining the frequency at a constant level is a key challenge in power system operations, as to do so involves balancing the supply of electricity against demand on an instantaneous basis. Any imbalance will cause the frequency to change: to increase where generation exceeds load and to decrease where load exceeds generation.

Large deviations from the normal frequency level (50 Hertz in Australia) or rapid changes in frequency can lead to instability in the system and cause the disconnection of generation or load. Uncontrolled disconnections have the potential to lead to cascading failures and, ultimately, a "black system" where part or all of the electricity network is de-energised. Consequently, it is important that the power system is able to resist changes in frequency arising from unexpected losses of generation, load or transmission lines until such time as the supply-demand balance can be restored.

The ability of the system to cope with these sudden imbalances is determined by the inertia of the power system. Inertia is naturally provided by spinning generators, motors and other devices that are synchronised to the frequency of the system. Historically, in the NEM, plentiful inertia has been provided by conventional generators, such as coal and gas-fired power stations and hydro plant.

However, many new generation technologies, such as wind turbines and photo-voltaic panels, are not synchronised to the grid, have low or no physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in frequency. The shift in the generation mix towards non-synchronous generation consequently gives rise to increasing challenges in maintaining the system in a secure operating state.

Non-synchronous generators also do not contribute to system strength as much as synchronous generating units. System strength relates to the size of the change in voltage for a change to the load or generation at a connection point. When the system strength is high at a connection point, the voltage changes very little for a change in the loading; however, when the system strength is lower, the voltage would vary more with the same change in load.

Reduced system strength in certain areas of the network may mean that generators are no longer able to meet technical standards and may be unable to remain connected to the power system at certain times. Challenges in maintaining voltage stability and network protection issues may have yet further impacts.

The shift to non-synchronous generation has been more pronounced in some regions of the NEM than others. South Australia, in particular, has experienced a substantially faster change than other regions. When the interconnector to Victoria is in service, South Australia is able to access inertia across the NEM. However, when there is an unexpected outage of the interconnector at high loading, the risks to system security in South Australia increase significantly. As the generation mix changes across the NEM, these risks may become more widespread.

System security work program

The AEMC's System Security Market Frameworks Review will consider changes to wholesale energy market frameworks to complement the shift to non-synchronous forms of generation. The Review will address power system security issues identified above to assist AEMO in maintaining power system security as the industry transforms.

The impact of non-synchronous generation on power system security was highlighted in the AEMC's Strategic Priorities for Market Development as an important focus in the coming years and this review has been initiated by the Commission to continue its work in this area.

The Review will draw upon the work undertaken to date by AEMO as part of its Future Power System Security (FPSS) Program, initiated in December 2015.

AEMO has significant work packages to identify the full nature of future power system limitations as well as the technical capability of new technologies to address these needs. AEMO is working in collaboration with the AEMC providing technical input to the System Security Market Frameworks Review to assist with the AEMC's development and implementation of any recommendations to change market and regulatory frameworks.

The AEMC has also received three rule change requests relating to a number of similar and related power system security issues.

The South Australian Minister for Mineral Resources and Energy and AGL have both submitted rule change requests proposing the introduction of new mechanisms for the provision of additional system security services to support power system frequency. The South Australian Minister for Mineral Resources and Energy has also submitted a rule change request to address the reductions in system strength.

These rule changes are being progressed concurrently and in coordination with the AEMC's Review. Therefore, as the Commission identifies solutions it can move directly to implementation by making rules based on these rule change requests.

These rule change requests deal with a range of complex issues for which technical solutions have not yet been fully explored, both within the NEM as well as internationally. The Commission initiated the System Security Market Frameworks Review as a vehicle to coordinate the assessment of these inter-related issues and develop appropriate recommendations for future policy changes and potential rule changes. Accordingly, the Commission has extended the period for making the draft rule determinations with respect to these rule change requests by 29 June 2017.

Two additional rule change requests have been received from the South Australian Minister for Mineral Resources and Energy in relation to emergency frequency control schemes. These two rule change requests are being progressed separately to the review and rules arising from these rule change requests may address some of the more immediate concerns in relation to the governance and operation of emergency protection schemes, particularly as it applies to managing the impact of a sudden separation of South Australia from the rest of the NEM.

In accordance with the statutory timelines, the Commission intends to publish draft determinations on these two rule change requests on 22 December 2016.

Preliminary findings

The main focus of the Commission's work over this initial stage of the review has been on the factors that influence the ability to maintain control of power system frequency following a contingency event, such as the loss of a large generator, load or transmission line. These can be considered through the following three-part framework:

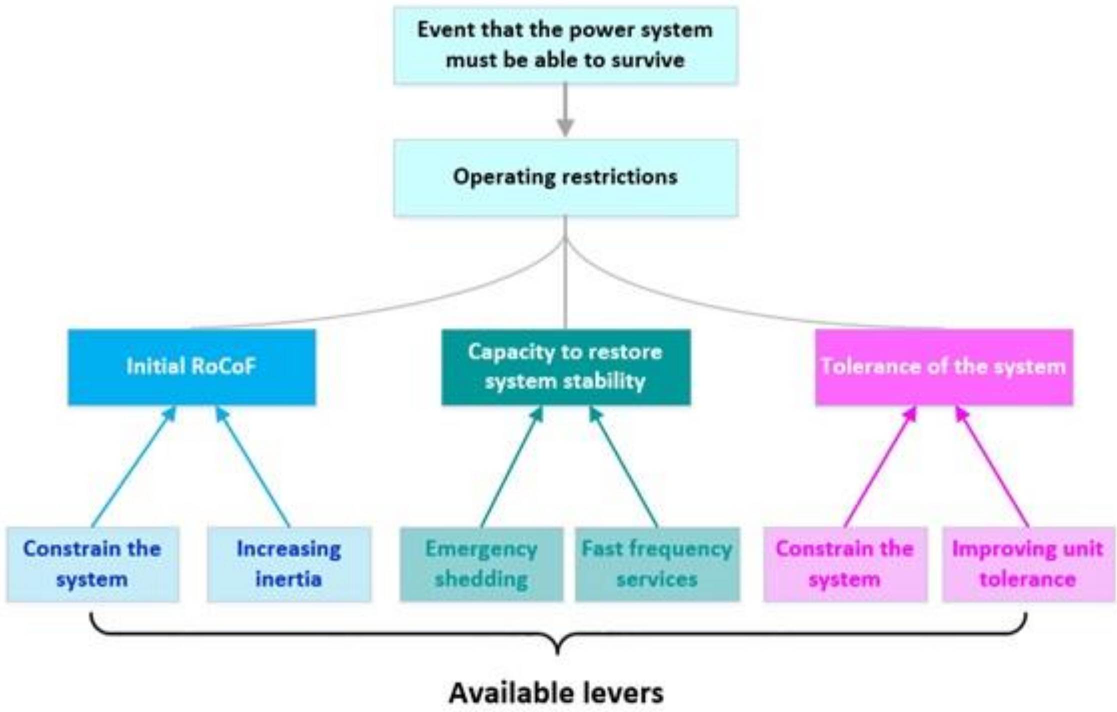
1. The initial rate of change of frequency (RoCoF), influenced by the size of the contingency and the level of system inertia.

2. The capacity to restore the stability of the system through the use of frequency response services.

3. The ability of generators and loads to withstand or "ride-through" changes in frequency.

This framework is illustrated in figure 1.

Figure 1 Factors that influence the control of power system frequency



Initial rate of change of frequency

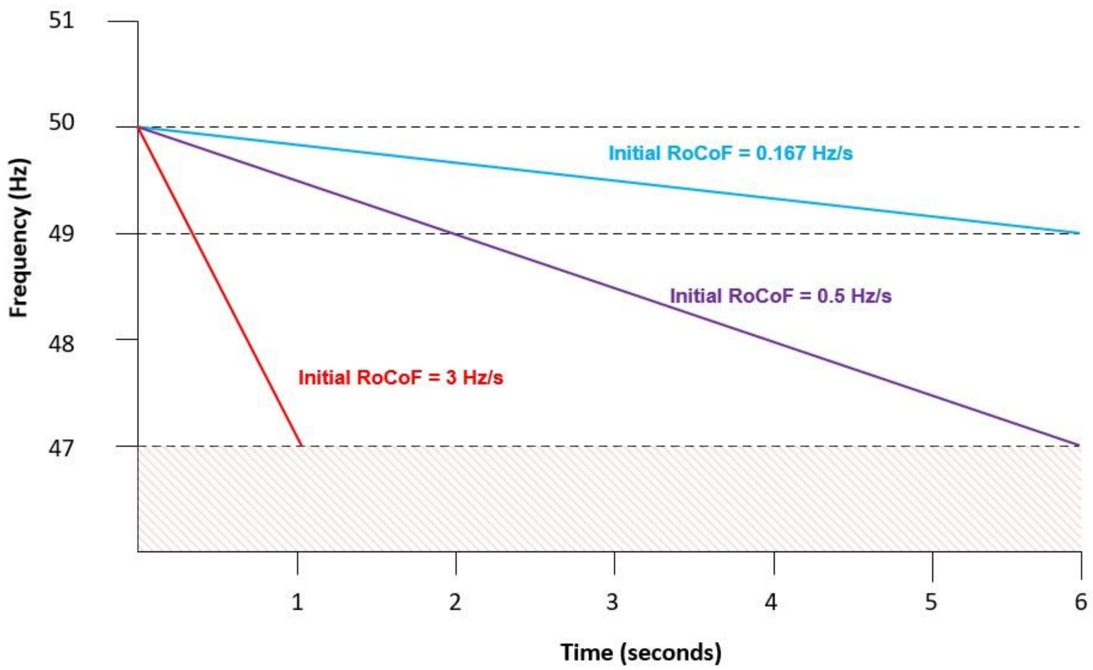
The rate at which the frequency changes determines the amount of time that is available to arrest the decline or increase in frequency before it moves outside of the permitted operating bounds.

Figure 2 illustrates how the rate that the frequency changes determines the amount of time available. The three lines in the figure show the potential impacts on the level of frequency from different levels of initial RoCoF. The figure assumes that a loss of generation occurs with the system frequency at 50 Hz, that there are no services available to arrest the decline in frequency until six seconds after the contingency event – the time period associated with the current fastest response service – and that all generating units can tolerate the frequency change:

- For the frequency to remain within the current operational frequency tolerance band (above 49 Hz), the initial RoCoF cannot exceed 0.167 Hz/s (blue line).
- For the frequency to remain within the current extreme frequency excursion tolerance limit (above 47 Hz), the initial RoCoF cannot exceed 0.5 Hz/s (purple line).
- An initial RoCoF of 3 Hz/s would lead to the frequency falling below the extreme frequency excursion tolerance limit after one second (red line).

Figure 2 illustrates the scale of the challenges posed by the high levels of RoCoF that are now possible in certain parts of the NEM, most notably South Australia.

Figure 2 Initial RoCoF determines the time available to respond

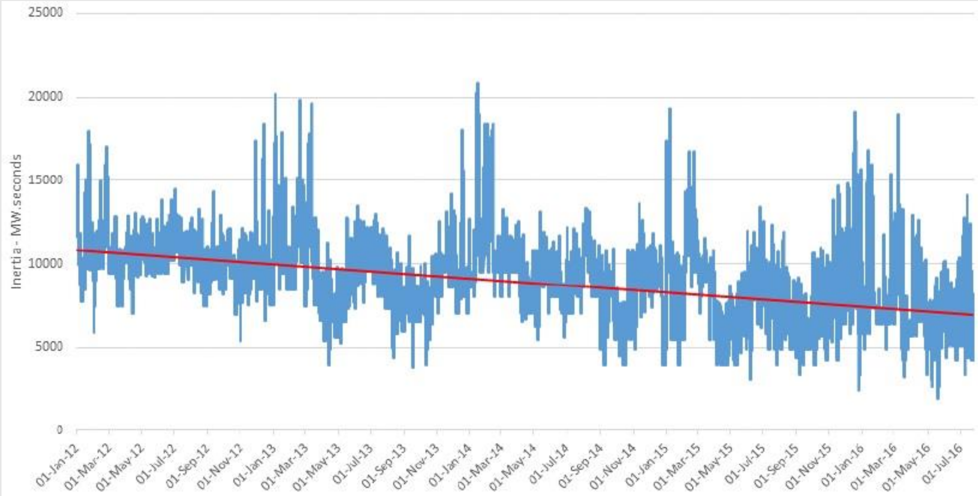


Box 1 Current frequency issues in South Australia

Investigations undertaken through AEMO's Future Power System Security Program have shown that the initial challenges of restricting high rates of change of frequency are most acute in South Australia.

South Australia has experienced a high level of investment in non-synchronous generation relative to its total generation capacity. In addition, a number of conventional synchronous generators have recently retired. Figure 3 shows AEMO's analysis of decreasing levels of system inertia in South Australia over time.[1]

Figure 3 System inertia in South Australia over time



AEMO notes that this decline in system inertia does not affect the stable operation of the power system in South Australia as long as the Heywood Interconnector to Victoria remains in service. This is because system inertia is provided to South Australia via the AC link.

However, an unexpected failure of the Heywood Interconnector may see insufficient inertia available in South Australia to maintain secure operation of the islanded system. The recent upgrade of the Heywood Interconnector has increased the size of the contingency that would result.

Prior to the occurrence of a contingency event, there are two actions that could be taken to minimise the resulting initial frequency change:

- constrain the power system to minimise the size of the contingency; and/or
- increase the level of inertia in the system to resist the initial frequency change.

AEMO already has the ability to introduce constraints that alter the operation of the power system. Constraints to control the RoCoF would limit the maximum contingency size, relative to the amount of inertia online. However, the effect of a binding constraint is likely to be an increase in the wholesale electricity price. For example, a constraint that restricts flows on an interconnector may limit the ability of power to be sourced from a lower priced generator in another region.

1 AEMO, *Future Power System Security Program – Progress Report*, August 2016, p. 21.

An alternative to constraining the system to limit the contingency size would be to increase the level of inertia in the power system. A higher level of inertia would permit the occurrence of larger contingencies for a given level of initial RoCoF.

There is currently no ability for AEMO or any other party to obtain additional inertia. In the past, inertia has been plentiful and so such a mechanism has not previously been required. The Commission has reached a preliminary view that the ability to maintain power system security in an efficient manner would be enhanced by the development and introduction of a mechanism to obtain inertia.

Such a service could be provided by any synchronous machine, including synchronous generators, mechanical loads and synchronous condensers. Synchronous condensers are large machines similar to those used in synchronous generating units but not including turbines to convert the energy from a fuel source to electrical energy.

International experience suggests that is not currently possible to operate a large power system without some synchronous inertia, and that "synthetic" inertia from non-synchronous generators does not provide a direct replacement.[2] Consequently, any inertia service in the NEM would have to initially be provided by synchronous machines.

However, in the future, it may become possible to use inverter-connected devices to constantly and "instantaneously" maintain frequency.[3] Consequently, the inertia service should be defined in such way as to accommodate new technology options.

Capacity to restore the system to stability

Limiting the initial rate of change of frequency will only act to increase the amount of time before frequency moves outside of acceptable bands. Inertia does not act to arrest the frequency change or revert frequency back to normal operating levels.

In the NEM, AEMO is responsible for maintaining the system frequency within the Frequency Operating Standards (FOS). Under the FOS, AEMO is required to maintain the system frequency within the operational frequency tolerance band of 49.0 to 51.0Hz for a reasonably possible ("credible") contingency event.

To maintain system frequency within these limits, AEMO is able to procure Frequency Control Ancillary Services (FCAS). In particular, "contingency FCAS" is used to control frequency in response to major variations caused by contingency events such as the loss of a generating unit or a significant transmission line. Contingency FCAS acts to arrest steep rates of change of frequency and then stabilises and recovers the system frequency over time to bring it back to within the normal operating frequency bands.

There are six contingency FCAS markets: six-second, 60-second and five-minute markets for both raise and lower services. The six-second service is currently therefore the quickest acting.

2 DGA Consulting, *International Review of Frequency Control Adaption*, 14 October 2016, p. 3.

3 DGA Consulting, *International Review of Frequency Control Adaption*, 14 October 2016, p. 3.

As shown above, in the event of a frequency deviation away from 50 Hz, for the system to remain with the current operational frequency tolerance band of ±1 Hz after six seconds, the initial RoCoF cannot exceed 0.167 Hz/s. In the context of the levels of inertia now observed in South Australia, this represents a relatively low level of RoCoF. Additionally, and as discussed later, there are no technical reasons why a higher level of RoCoF could not be permitted in terms of the ability of generators and loads to tolerate this.

To permit a greater level of RoCoF for credible contingency events would require the development of a faster-acting contingency FCAS, which has come to be termed a “fast frequency response (FFR) service”. The Commission has consequently reached a preliminary view that the development of an FFR service would be beneficial in that it would provide greater flexibility in the level of RoCoF that could be permitted and, hence, a more efficient amount of inertia to be procured.

The Commission anticipates undertaking further work with AEMO to develop a technical specification for a FFR service. However, such a service might be expected to act somewhere in the range of half a second to two seconds. A one-second service would imply that a RoCoF of 1 Hz/s could be permitted.

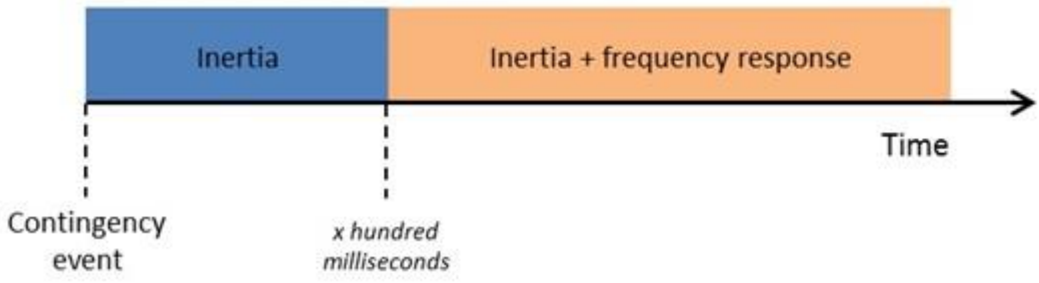
While synchronous generators currently provide the majority of six-second raise FCAS, it appears unlikely that such generators would be able to respond in the timeframes demanded by a FFR service. Rather, this faster response might be provided by inverter-based generators such as wind turbines, by energy storage devices and by demand-response schemes.

Fast frequency response services are not a mature technology and no international jurisdiction has any significant experience operating a FFR-type service. However, a two-second FFR service was implemented in Ireland in October 2016 and a one-second demand response service is used in New Zealand. Consequently, the Commission’s preliminary view is that the technology is likely to be sufficiently advanced as to support the specification of such a service now and to allow technical options for its provision to develop over time.

While a number of technologies exhibit very rapid response times, the physical realities of accurately measuring frequency changes may limit the response capabilities of FFR technologies.

The time delay of FFR technologies implies that there is a minimum level of inertia that must be online at any point in time to resist frequency changes caused by contingency events. The inertia would slow the frequency change to provide time for frequency response services to be activated. Beyond this initial time period, fast frequency response technologies have the potential to be used in combination with inertia to stabilise system frequency. This distinction between the roles of the two services is illustrated in figure 4.

Figure 4 Timeline for inertia and fast frequency response



The level of required inertia can be divided into two components:

1. **System security** – the minimum level of inertia required to maintain secure operation of the power system and slow frequency changes caused by contingency events to allow an effective response from frequency control services.

2. **Market benefits** – additional inertia which lowers the overall cost of maintaining system security through alleviation of constraints on the network. This level of inertia would be determined on the basis of an economic trade-off against the alternatives of obtaining additional fast frequency response or constraining the system.

Tolerance of the system

In designing a framework for inertia and FFR services, and consequently a RoCoF limit, it will be important to understand the tolerance of the system to that level of RoCoF. A RoCoF limit of 2 Hz/s would not be effective if the maximum RoCoF that could be tolerated by generators and loads was 1 Hz/s.

In practice, generators and loads will have a range of withstand capabilities. While it will likely be important to understand these in general, that will particularly be the case for equipment providing inertia and FFR services. For example, a generator contracted to provide inertia would need to be able to withstand RoCoF to at least the targeted RoCoF limit.

The performance standards relating to the ability of generators to withstand rates of change of system frequency are set out in the National Electricity Rules (NER or rules). These standards have been imposed as a condition of generator connection agreements since 2007.

The current standards are automatically met if a generating unit can withstand a RoCoF of ±4 Hz/s for quarter of a second. Generators may negotiate a lower standard, but the minimum standard is ±1 Hz/s for one second. There is no obligation on generators to remain connected to the system through an event where RoCoF exceeds those levels, even if the frequency remains within the bounds of the FOS.

The withstand capability of generators that connected prior to 2007 is largely unknown. While historical incidents can provide some indication of the withstand capability of these generators, the capability of any particular generator to withstand high RoCoF is largely dependent on the operating and market conditions that were present at the time of the event.

Over the remainder of the review, the Commission anticipates giving further consideration to these issues, in particular the appropriateness of the current generator performance standards and whether it is necessary for work to be undertaken to better understand the withstand capability of generating units connected prior to 2007.

Consequences for system strength

In addition to reducing system inertia, the reduced number of synchronous generating units has meant that the system strength in some areas of the NEM power system has also decreased.

Historically, the primary concern has been that system strength may be too high such that fault currents may damage equipment. This is because networks have been reinforced and additional generation has been installed over time as the demand for electricity has increased.

However, more recently, system strength in some parts of the power system has been decreasing as the number of traditional synchronous generators are operating less or being decommissioned. This is anticipated to cause a number of issues, including a reduction in:

- the capability of some transmission and distribution network protection systems, which rely on a high fault current, to operate effectively;
- the ability of network operators to manage voltages within their networks; and
- the ability of generators to operate correctly such that they can meet their technical performance standards, which can increase the risk of cascading outages leading to major supply disruptions.

The number, size and location of synchronous generators, synchronous condensers, and synchronous loads determines the ability to manage both frequency and system strength. Increasing the quantity of synchronous generation and synchronous condensers both provides inertia to assist in the management of frequency and increases system strength.

Therefore, when assessing the different potential options for managing frequency, it is important to also consider the impact on system strength.

Options to obtain additional system security services

The Commission has identified a number of potential options for obtaining inertia and fast frequency response services. An overall solution to the management of system frequency is likely to involve the development of a combination of the options.

Guiding principles

A number of principles have been developed to guide the assessment of the options for obtaining additional system security services. The trade-offs that need to be made between these principles means that it is necessary to consider the design of the services carefully.

1. *Risk allocation*

   System security is necessary for the efficient functioning of the power system and benefits all market participants as well as the wider community. However, there are costs associated with maintaining the power system in a secure operating state.

   A trade-off exists between the level of costs that should be incurred in avoiding or minimising the impact on the system should a disturbance occur, and the probability of the level of costs that would likely be incurred as a result of the failure to maintain the system in a secure operating state.

   Costs of avoiding or minimising the impact on the system may include the application of limits on transmission lines or constraining off generation to limit the size of the impact should these generation or network elements suddenly fail. It may also include the upfront costs of enabling the provision of frequency response services to stabilise the system should a supply disruption occur.

   Risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by customers. Solutions that allocate risks to market participants, such as businesses who are better able to manage them, are preferred where practicable.

2. *Certainty versus flexibility*

   Achieving a secure operating system in an economically efficient manner requires market frameworks to be designed to encourage investment in system security services and to maximise flexibility in the provision of those services.

   The extent to which services are likely to be provided over the long term may be dependent on the level of certainty that can be provided in relation to investment. A secure power system demands the availability of system security services at all times. Regulatory frameworks must be designed to accommodate this requirement by providing certainty to prospective investors as well as existing providers. However, while greater investment certainty may help to make sure that the services are available when they are needed, this may come at the expense of the flexibility to continuously adjust the requirement under changing market conditions.

3. *Technology neutrality*

   Arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly and, to the extent possible, a change in technology should not require a change in regulatory arrangements.

   When considering how regulatory arrangements accommodate new technologies, it is the functions they perform that need to be the focus not the technologies themselves. While inertia and fast frequency response may have separate but related roles to play in stabilising the system, there are a variety of technologies that are capable of providing each of these services.

4. *Competition*

   Competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning since they are more flexible to changing conditions and give businesses the ability to meet consumers' needs as efficiently as possible. Such outcomes should be less likely to change over time, creating regulatory certainty. Markets should be designed to maximise opportunities for the provision of services in order to send the right price signals and lower the overall cost of achieving a secure electricity system.

   However, requiring solutions that address issues in specific network locations may limit the ability to maximise opportunities for service provision. System frequency is a global issue while system strength issues tend to be locationally specific. The range of service providers that are available to address system frequency may narrow if the same service providers are also required to address issues of system strength.

Potential procurement options

In light of its preliminary finding that there are two distinct new services required to enhance NEM system security the Commission has identified a suite of potential mechanisms for provision of these services.

As noted above, the different characteristics of these new services and the role they would play may result in different procurement paths being taken for each. Putting in place new markets or requirements that are not carefully designed, risks customers and market participants bearing unnecessarily higher costs for a long time, stifling innovation or not effectively stimulating sufficient response to address the security challenges.

Potential new mechanisms for the provision of additional system security services could include:

1. *Generator obligation* – The imposition of a minimum technical standard on each generator in the NEM, which could involve:

(a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or

(b) an option for generators to enter into an agreement with another provider.

2. *AEMO contract process* – The procurement of services via contracts with individual market participants through a competitive tender process or bilateral negotiated process undertaken by AEMO.

3. *TNSP provision* – The direct provision of services by TNSPs or the procurement of services by TNSPs under a modified Network Support and Control Ancillary Service (NSCAS) framework.

4. *Five-minute dispatch* – Prices are set for the services on a five-minute basis, which could involve:

   (a) the services incorporated in the dispatch process with a price paid to providers based on the value of the service in the five-minute dispatch interval; or

   (b) a separate market with offers submitted by providers of the services and a price determined for each five-minute interval.

Next steps

This Interim Report performs two separate functions:

1. Provides an update to the COAG Energy Council on the AEMC's progress in relation to the System Security Market Frameworks Review, in accordance with the terms of reference published in July 2016.

2. Seeks stakeholder feedback on the AEMC's findings to date and potential changes to market arrangements, including roles and responsibilities and the design of options to obtain system security services.

As the next stage of the System Security Market Frameworks Review, the AEMC intends to refine the range of potential options to deliver the system security services based on stakeholder input and assessment against the guiding principles. The AEMC will draw upon advice received from stakeholders as part of this consultation process as well as submissions received during the previous round of consultation that was held in September 2016.

The AEMC's conclusions and draft rules are also likely to be influenced by any physical and technical limitations of implementing the options or providing the services. The AEMC will continue to work closely with AEMO and representatives of the technical working group on system security.

The ultimate output of the Review will be a report to the COAG Energy Council highlighting rule changes and technical changes made in response to the rule change requests received, and recommendations for further action where required, including possible changes to policy or legislative frameworks or recommendations in relation to potential future rule change requests.

Contents

1 Introduction

On 14 July 2016, the Australian Energy Market Commission (AEMC or Commission) initiated a review into the regulatory frameworks that affect power system security in the National Electricity Market (NEM).[4]

The AEMC's System Security Market Frameworks Review will consider changes to wholesale energy market frameworks to complement the shift to non-synchronous forms of generation. The Review will address power system security issues identified above to assist Australian Energy Market Operator (AEMO) in maintaining power system security as the industry transforms.

The impact of non-synchronous generation on power system security was highlighted in the AEMC's Strategic Priorities for Market Development as an important focus in the coming years and this review has been initiated by the Commission to continue its work in this area.

The System Security Market Frameworks Review will draw upon the work undertaken to date by AEMO as part of its Future Power System Security (FPSS) Program, initiated in December 2015.

The AEMC has also received five rule change requests relating to a number of similar and related power system security issues.[5] These rule changes are being progressed concurrently and in coordination with the AEMC's Review.

1.1 Outline of this paper

This paper:

- provides an update on the AEMC's system security work program and the progression of thinking in relation to current power system security issues and potential technical solutions;
- discusses the economic considerations that should be taken into account in the design of market and regulatory frameworks to manage system security and explores a number of options to obtain additional system security services;
- provides an update on the AEMC's assessment of the rule change request submitted by AGL and two of the four rule change requests submitted by the South Australian Minister for Mineral Resources and Energy; and
- outlines the process for making submissions.

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4 The review was initiated by the AEMC under section 45 of the NEL. Regulatory frameworks refer to the National Electricity Rules and the National Electricity Law.

5 Information on these rule change requests can be found on the AEMC website - http://www.aemc.gov.au/Rule-Changes.

1.2 Concepts and background to the review

The electricity industry in Australia is undergoing fundamental change as the proportion of newer types of electricity generation, such as wind and rooftop solar, increases. A large share of this new generation resides within distribution networks and is not centrally controlled by the market operator.

New approaches to maintaining power system security are needed because of the physics of maintaining technical generation parameters like voltage and grid frequency.

AEMO is responsible for maintaining the power system in a secure operating state. Power system security is defined in the rules as the safe scheduling, operation and control of the power system in accordance with the power system security principles.[6] These principles include maintaining the power system in a secure operating state and returning the power system to a secure operating state following a contingency event or a significant change in power system conditions, including a major supply disruption. Power system security is interrelated with the technical parameters of the power system such as power flows, voltage, frequency, the rate at which these might change and the ability of the system to withstand faults.

System frequency

In order for AEMO to maintain the electricity system in a secure operating state, the frequency of the system must be maintained within a defined range. Rapid changes in frequency or large deviations from normal operating frequency can lead to instability in the system and the potential disconnection of generation or load.

The ability of the power system to resist large changes in frequency arising from the loss of a generator, transmission line or large industrial load is initially determined by the inertia of the power system. Inertia is naturally provided by large spinning conventional generators that are synchronised to the frequency of the system.

Conventional electricity generation, like hydro, coal and gas, operate with large spinning turbines and alternators that are synchronised to the frequency of the grid. These generators have significant physical inertia and support the stability of the power system by working together to maintain a constant operating frequency.

Currently, newer types of electricity generators connected to the national electricity system, such as wind and rooftop solar, are not synchronised to the grid, have low physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in frequency. Some of these technologies have the capability to rapidly respond to changes in electricity supply or consumption, and are likely to play a key role in using these services to manage the future security of the power system. However, these services are currently not actively employed in the NEM and are the subject of ongoing investigations by AEMO.

6 Chapter 10 of the NER.

Historically, most generation in the NEM has been synchronous and, as such, the inertia provided by these generators has not been separately valued. As the generation mix shifts to smaller and more non-synchronous generation however, inertia is not provided as a matter of course giving rise to increasing challenges for AEMO in maintaining the power system in a secure operating state.

The shift to newer types of generation has been more pronounced in some regions of the NEM than others. South Australia, in particular, has experienced a substantially faster change than other regions as an increasing volume of renewable energy is integrated. Flows on the interconnector with Victoria allow power system security to be maintained because of inertia provided by generators in other parts of the NEM. Where there is an outage of this interconnector, the risks to system security in South Australia increase significantly because it must rely on inertia provided by generators within the region. If there is minimal generation capacity online at the time, with the ability to provide inertia in that region, the frequency could be subject to very rapid changes. As the generation mix changes in a similar way across the NEM these risks may become more widespread.

System strength

A secure operating system also requires generating units and network components to be able to operate continuously following a major fault or disturbance to the power system.

System strength is an inherent characteristic of a power system and it relates to the size of the change in voltage for a change to the load (or generation) at a connection point. When the system strength is high at a connection point the voltage changes very little for a change in the loading, however, when the system strength is lower the voltage would vary more with the same change in load.

Unlike inertia, system strength is a local phenomenon. Recently, the system strength has been reducing in some parts of the NEM power system as a number of synchronous generating units exit the market and are replaced by new generating units, which are non-synchronous, and do not contribute as much to system strength.

Reduced system strength in certain areas of the network may mean that generators are no longer able to meet technical standards and may be unable to remain connected to the power system at certain times. Challenges in maintaining voltage stability and network protection issues may have yet further impacts.

1.3 System security work program

On 14 July 2016, the AEMC published a terms of reference for its self-initiated System Security Market Frameworks Review. For any proposed solutions, the terms of reference require the AEMC to:

- identify the reasons for the proposed change and likely impacts on the power system, the NEM and consumers; and

- describe pathways to implementation, including timing, possible interim stages and any necessary changes to the National Electricity Law or National Electricity Rules.

The Review draws upon the work currently being undertaken by AEMO as part of its FPSS Program, initiated in December 2015.

AEMO has undertaken extensive work to identify and prioritise current and potential future challenges to maintaining system security. These challenges all stem from the transition to greater levels of non-synchronous generation, including:

- high rates of changes of system frequency following a sudden change in supply or demand as a result of reduced levels of system inertia. A reduction in synchronous generation may reduce the availability of frequency control ancillary services to respond to high rates of change of frequency, with the remaining frequency control services, and emergency protections schemes, potentially being too slow to respond; and

- localised reductions in system strength which may mean that the power system is too weak, thereby reducing the effectiveness of some types of system protection functions, impacting the ability of some generators to ride through faults, and making the local network more susceptible to voltage instability.

A detailed discussion of these issues is contained in AEMO's Future Power System Security Program Progress Reports.[7] AEMO's work on these issues, and its work on the visibility of distributed energy resources, is ongoing.

As identified by AEMO and the proponents to the rule change requests, the transition to non-synchronous forms of generation has reduced levels of system inertia which has the potential to result in high rates of change of frequency following a significant change in generation or load.

Some technologies may have the capability to respond rapidly to high rates of change of frequency. However, these technologies provide a service which is distinct from inertia and the extent to which these technologies can act as substitutes for the reduced levels of system inertia is the subject of ongoing investigations by AEMO.

The AEMC's Review will identify the changes to market and regulatory frameworks that will be required to deliver the technical solutions identified by AEMO. These changes may include, but are not necessarily limited to, different mechanisms to competitively procure the required system security services, possible changes to standards or the establishment of new standards, or changes to the roles and responsibilities of market participants.

Any recommendations for potential changes to market and regulatory frameworks developed by the Commission will need to result in net benefits to the market and promote the National Electricity Objective (NEO). The Commission's assessment of the

7 AEMO, *Future Power System Security Program – Progress Report*, August 2016.

rule change requests and the development of recommendations in this review will also be guided by the following framework principles.

1. **Risk allocation**: Arrangements should be designed to explicitly take into consideration the trade-off between the risks and costs of meeting system security requirements.

2. **Certainty versus flexibility**: Arrangements must be flexible in a changing market environment and remain effective in achieving system security over the long term. This must be balanced against the need to provide investment certainty.

3. **Technology neutral**: Arrangements should be designed to take into account the full range of potential market and network solutions.

4. **Competition**: Competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning.

The costs of managing a secure power system

Failure to maintain the power system in a secure operating state may have potential consequences for the health and safety of individuals and may result in substantial costs to market participants and the wider community. Costs may include damage to equipment, lost production, and the time and expense of restoring the system. Depending on the extent of the failure, other societal costs may be incurred.

A secure power system is an essential requirement to meet the electricity needs of Australians and, as such, market frameworks must be designed to provide the necessary means to maintain the system in a secure operating state at all times.

Accountability for investment decisions in the services required to maintain system security should rest with those parties best placed to manage them. The extent to which a secure power system can be maintained over the long term may be dependent on the level of certainty provided to these investors.

However, a rapidly evolving market environment is likely to require different approaches to managing system security over time. Putting in place new markets or requirements that are not carefully designed, risks customers and market participants bearing unnecessarily higher costs for a long time, stifling innovation or not effectively stimulating sufficient response to address the security challenges.

The rule change requests

The AEMC's System Security Work Program comprises the System Security Market Frameworks Review and the five related rule change requests received on system security matters. The rule change requests are summarised as follows:

1. **Inertia ancillary service market – AGL**

   AGL considers that less synchronous generation in the NEM is leading to a lack of system inertia. This is increasing the susceptibility of the system to rapid changes in frequency and reducing system stability.

   AGL has proposed that a new ancillary service mechanism be established to enable AEMO to procure inertia on a competitive basis when it is needed.

2. **Managing the rate of change of power system frequency – SA Minister for Mineral resources and Energy – SA 'A'**

   Similar to AGL's rule change request, this rule change request also raises as an issue the reduction in system inertia arising from less synchronous generation, leading to high rates of change of frequency and reduced system stability.

   The rule change request proposes that AEMO should be provided with powers to procure the necessary services to maintain power system security. The exact form of these services is not specified.

3. **Emergency under-frequency control schemes – SA Minister for Mineral Resources and Energy – SA 'B'**

   This rule change request suggests that less synchronous generation may result in changes in frequency that are too fast for existing emergency frequency control schemes to operate effectively. An increase in distributed energy resources may mean that existing schemes are less effective in shedding load to control frequency.

   The rule change request proposes the development of a regulatory framework to adapt existing emergency under-frequency control schemes to address changed power system conditions.

4. **Emergency over-frequency control schemes – SA Minister for Mineral Resources and Energy – SA 'C'**

   This rule change request raises the issue that the rules do not provide a mechanism for over-frequency emergency control schemes to account for unexpected frequency increases due to excess generation events.

   The rule change request proposes the development and establishment of a regulatory framework for emergency over-frequency control schemes to address sudden excess generation events.

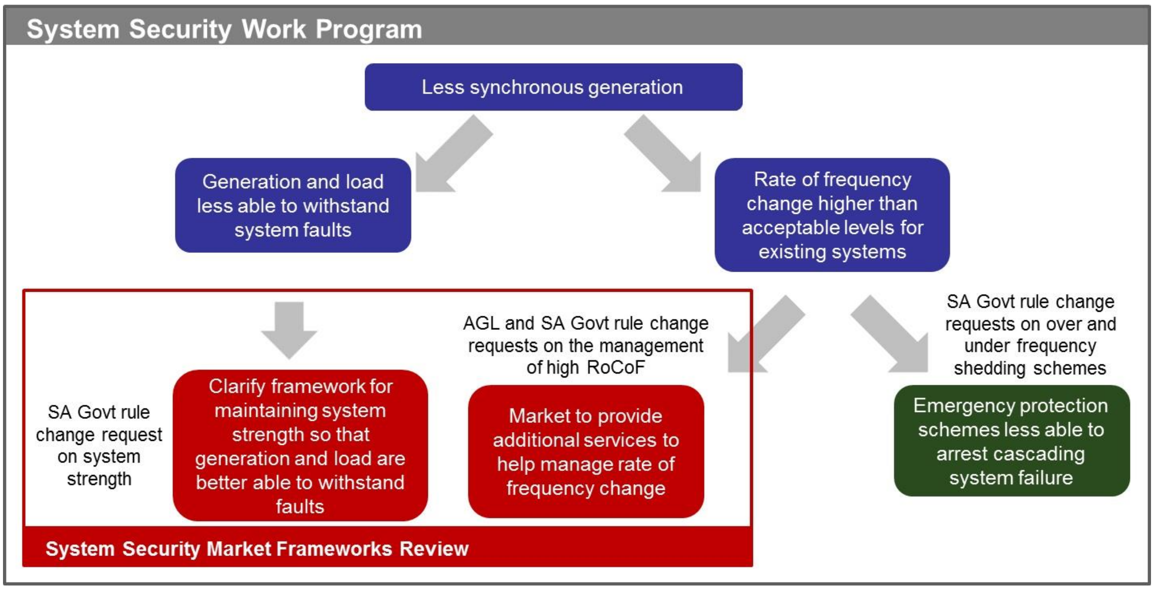
5. **Managing power system fault levels – SA Minister for Mineral Resources and Energy – SA 'D'**

   This rule change request raises as an issue the reduction in system strength associated with the retirement of synchronous generation and the entry of new non-synchronous generation. A reduction in system strength in certain areas of the network may mean that generators no longer meet technical standards and may be unable to remain connected to the system at certain times. Voltage instability and network protection issues may also arise.

The rule change request proposes that the rules should be changed to allocate responsibility for setting fault levels in different parts of the network that take account of cost, incentives and the allocation of risk.

Figure 1.1 shows the relationship between the issues being considered under the System Security Work Program and how these issues relate to the System Security Market Frameworks Review and the related rule change requests.

Figure 1.1 AEMC System Security Work Program



The AGL rule change request and the South Australian Government's rule change requests 'A' and 'D' are being progressed concurrently and in coordination with the AEMC's Review.

These rule change requests deal with a range of complex issues for which technical solutions have not yet been fully explored, both within the NEM as well as internationally. The Commission initiated the System Security Market Frameworks Review as a vehicle to coordinate the assessment of these inter-related issues and develop appropriate recommendations for future policy changes. Accordingly, the Commission has extended the period for making the draft rule determinations with respect to these rule change requests by 29 June 2017.

The South Australian Government's rule change requests 'B' and 'C' are being progressed separately to the Review and the other three rule change requests. Changes to the rules arising from these rule change requests may address some of the more immediate concerns in relation to the governance and operation of emergency protection schemes, particularly as it applies to managing the impact of a sudden separation of South Australia from the rest of the NEM.

In accordance with the statutory timelines, the Commission intends to publish draft determinations on these two rule change requests on 22 December 2016.

1.4 Structure of this report

The remainder of this interim report is structured as follows:

- Chapter 2 describes the current issues in the NEM in relation to power system security;
- Chapter 3 sets out a discussion of the potential technical solutions that have been identified to address the system security challenges that have arisen;
- Chapter 4 describes the economic considerations that are taken into account in the design of efficient market and regulatory frameworks to manage system security and the roles of the Reliability Panel and AEMO;
- Chapter 5 sets out a number of options for the provision of additional system security services; and
- Chapter 6 sets out the process for lodging a submission.

2 Maintaining system security in an evolving market

A secure operating system is a necessary condition for meeting consumer electricity needs. Up until very recently, the design of the power system has been based on the operation of conventional synchronous generating units and there has been little need to consider significant changes to regulatory frameworks to maintain system security. However, the last decade has seen a rapid rise in the penetration of new generation technologies, such as wind farms and rooftop solar, and the closure of a number of large conventional generators. In this environment, new approaches to maintaining power system security are likely to be required.

Based on the work undertaken to date by AEMO as part of its Future Power System Security Program, there are four principal issues for which potential changes to market and regulatory frameworks may be required:

1. The ability to manage changes in frequency in a power system with diminishing levels of inertia.
2. The reduction in system strength in certain parts of the network which may affect the ability of network businesses to maintain stable voltages and for generators to operate continuously following a disturbance to the power system.
3. The capability of emergency protection schemes to operate effectively with rapid changes in system frequency.
4. The ability of AEMO to assess the operational limits of the power system with increasing penetration of distributed generation.

This chapter explains the concept of power system security, describes the recent changes in the physical power system that have given rise to challenges in maintaining power system security, and identifies their potential consequences if left unaddressed.

2.1 What is power system security and why does it matter?

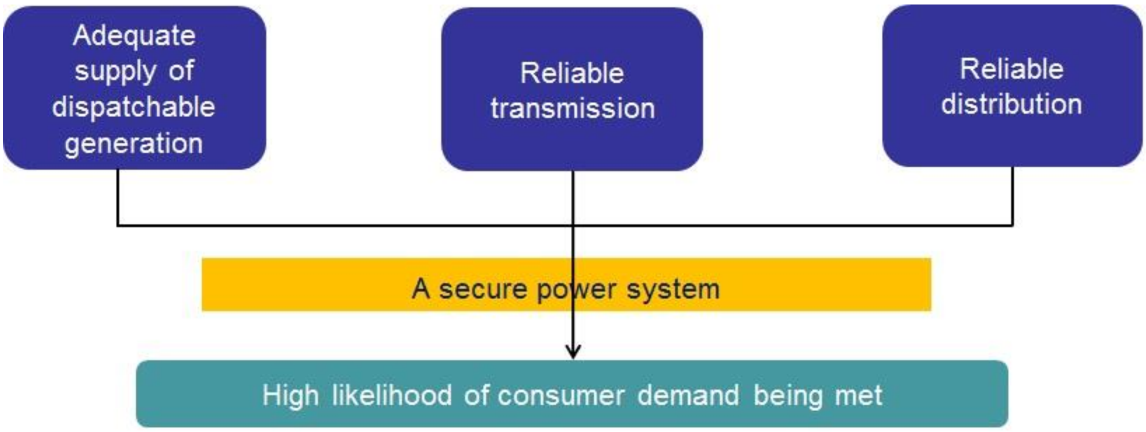
System security is necessary for the efficient functioning of the power system. In the NEM, AEMO is required under the National Electricity Rules (NER or rules) to operate and maintain the power system in a secure operating state. In order for the electricity system to remain in a secure operating state, there are a number of physical parameters which must be maintained within a defined operating range. An electricity system that operates outside of these physical parameters may become unstable, jeopardise the safety of individuals, risk damage to equipment, and lead to the possibility of blackouts.

System security is distinct from reliability

System security is distinct from reliability. The concepts of 'reliability' and of 'reliable supply' have a consumer focus and describe the likelihood of supplying all consumer needs with the existing generation capacity and network capability. As shown in Figure 2.1, the components of reliability include an adequate supply of dispatchable generation to meet demand and reliable transmission and distribution networks.

A secure operating system is a necessary condition for meeting consumer electricity needs. Security of supply is a measure of the power system's capacity to continue operating within defined technical limits, even in the event of the disconnection of a major power system element such as an interconnector or large generator.

Figure 2.1 Components of system security and reliability



Reliability has historically been the focus of greater attention than system security. AEMO must continuously monitor levels of available generation as plants age, retire from the market, and are replaced by new generators. Investments in transmission and distribution networks are ongoing and involve a trade-off between the cost of building and maintaining the networks and the value placed on reliability by customers.

In contrast, the factors that drive system security have changed very little over time. The services that generators and network businesses provide that support system security, such as inertia and voltage control, have historically been sufficient to maintain system security. AEMO has performed its role of continuously monitoring power system security and operating the power system in a secure operating state. Up until very recently, the design of the power system has been based on the operation of conventional synchronous generating units and there has been little need to consider significant changes to regulatory frameworks to maintain system security.

2.2 Why are we focusing on system security now?

The electricity industry in Australia is undergoing a fundamental transformation. The last decade has seen a rapid rise in the penetration of new generation technologies, such as wind farms and rooftop solar. In the past, these technologies accounted for only a small fraction of total electricity supply. Now they are a critical part of our electricity system and are expected to continue to provide an ever increasing proportion of Australia’s electricity needs in the future. At the same time, the market has experienced the closure of a number of large conventional generators. These changes mean that the way we maintain system security also needs to change.

Currently, wind and photovoltaic (PV) technologies operate differently to more conventional forms of electricity generation, such as hydro, coal or natural gas. The existing fleet of these newer technologies are limited in their ability to provide the range of other power system security services that are ancillary to the generation of electricity but necessary to maintain the secure operation of the electricity system. Most notably, they are not synchronised to the frequency of the electricity system and therefore are currently unable to assist in dampening instantaneous rapid changes in frequency.

Further, some non-synchronous technologies are installed within distribution networks and are not centrally controlled. They are, in many instances, intermittent in their production of electricity, only generating when the wind blows or the sun shines. This affects AEMO's ability to control the secure operation of the system and maintain a continuous supply of electricity across the interconnected network.

System security is particularly relevant in South Australia

The falling levels of synchronous generation combined with rising levels of non-synchronous generation (a large proportion of which is distributed) are presenting new challenges for AEMO in the secure operation of the power system. This is particularly the case in South Australia, where:

- region demand for electricity has been declining;
- the available wind and solar resources have led to substantial investment in wind farms and rooftop solar PV; and
- conventional, synchronous generation has progressively withdrawn from the market.

South Australia relies heavily on the interconnectors with Victoria, both to meet consumer demand and to contain energy costs. The interconnectors (ie Heywood and Murraylink) are an essential part of the supply mix in South Australia.[8]

However, given the amount of power supplied via Heywood relative to South Australian demand, its loss represents a significant threat to system security. Loss of Heywood would simultaneously result in:

- South Australia separating from the rest of the NEM, leaving it to rely on inertia produced by local generation.
- An immediate imbalance between load and generation caused by loss of Heywood. The greater the flow on Heywood at the time, the greater the imbalance and the attendant consequences for system security.

The changing generation mix has consequences for the whole of the NEM

We have focused on the challenges that are already emerging in South Australia. But as the generation mix changes in a similar way across the NEM, these challenges and issues may become more widespread. New approaches and tools are required to manage system security as efficiently as possible.

8 Murraylink is a high-voltage direct-current interconnector, the design of which does not transfer inertia between Victoria and South Australia.

Table 2.1, provided by AEMO, shows the total installed generation capacity in the NEM in terms of physical attributes as at June 2016.

Table 2.1 Total installed generation capacity in the NEM[9]

<table>
<tr><th>Generation capacity (MW) (% of total)</th><th>Queensland</th><th>New South Wales</th><th>Victoria</th><th>South Australia</th><th>Tasmania</th></tr>
<tr><td>Synchronous (registered)</td><td>12,459 (89%)</td><td>15,416 (88%)</td><td>11,050 (83%)</td><td>2,999 (58%)</td><td>2,672 (87%)</td></tr>
<tr><td>Non-synchronous (registered)</td><td>12 (0.1%)</td><td>897 (5%)</td><td>1,230 (9%)</td><td>1,473 (29%)</td><td>308 (10%)</td></tr>
<tr><td>Non-synchronous (distributed)</td><td>1,585 (11%)</td><td>1,301 (7%)</td><td>957 (7%)</td><td>683 (13%)</td><td>97 (3%)</td></tr>
<tr><td rowspan="6">Interconnection</td><td colspan="2">Double-circuit AC connection NSW-QLD</td><td colspan="3" rowspan="2"></td></tr>
<tr><td colspan="2">Three cable DC connection NSW-QLD</td></tr>
<tr><td></td><td colspan="2">5 AC lines connecting NSW-VIC</td><td colspan="2"></td></tr>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Double-circuit AC connection VIC-SA</td><td rowspan="2"></td></tr>
<tr><td colspan="2">DC connection VIC-SA</td></tr>
<tr><td colspan="2"></td><td colspan="3">DC connection VIC-TAS</td></tr>
</table>

AEMO projects that the proportion of distributed intermittent generation will continue to grow across the NEM, with consumer choice, increasing availability of distributed energy resources, and government policies being the primary drivers of the speed and extent of this shift.

The AEMC considers that, in the face of this transition, regulatory frameworks that govern the operation of the NEM need to be flexible and resilient in order that these newer types of electricity generation can be effectively integrated into the market while maintaining the secure operation of the electricity system.

2.3 What are the challenges that we need to address?

Based on the work undertaken to date by AEMO as part of its FPSS Program, there are four principal issues that have been identified for which potential changes to market and regulatory frameworks may be required.[10] These issues relate to the transition

9 AEMO, *Future Power System Security Program – Progress Report*, August 2016, p. 9.

10 AEMO, *Future Power System Security Program – Progress Report*, August 2016, p. 17.

from conventional centrally dispatched synchronous generation to intermittent, and increasingly more distributed, non-synchronous generation, and include the following:

- **Managing frequency in a low inertia power system** – the diminishing levels of system inertia have increased the rate, or the speed, at which frequency will change following a disturbance. Existing system security services may be unable to respond effectively to these disturbances.
- **Reduced system strength** – in certain areas of the network the decline in synchronous generation has led to a decline in system strength. This may mean that generators are no longer able to meet technical standards and may sometimes be unable to remain connected to the power system.
- **Effectiveness of emergency frequency control schemes** – rates of change of frequency may be too fast for existing emergency frequency control schemes to operate effectively. Moreover, the increase in the penetration of distributed energy resources throughout the power system may mean that existing schemes are less effective in shedding load to control frequency.
- **Managing a power system with a high penetration of distributed generation** – as the penetration of distributed generation rises, it becomes increasingly important to the power system. Distributed generation is generally neither 'visible' to AEMO, nor is it controlled in the central dispatch process. Distributed generation is likely to create increasing challenges for AEMO in its ability to assess the operational limits of the power system, and dispatch utility-scale generation to meet residual load.

The AEMC will address the first two items as part of the System Security Market Frameworks Review, and will assess the third item under a separate work-stream. The fourth item on the visibility of distributed generation is likely to be the subject of future market framework development, although not currently part of this Review.

2.3.1 Managing power system frequency in a low inertia system

Management of power system frequency

The interconnected national electricity system operates within the constraints of a number of defined physical parameters. One such parameter is system frequency. Conventional electricity generation, like hydro, coal and gas, operate with large spinning turbines that are synchronised to the frequency of the grid. Changes to the balance of supply and demand for electricity can act to speed up or slow down the frequency of the system. Conventional generators support the stability of the power system by working together to maintain a constant operating frequency across the interconnected network.

In each generating unit, the large rotating mass of the turbine and alternator has a physical inertia which must be overcome in order to increase or decrease the rate at which the generator is spinning. In this manner, large conventional generators that are synchronised to the system act to dampen changes in system frequency. In the electricity system, the greater the number of generators synchronised to the system, the higher will be the system inertia, and the greater will be the ability of the system to resist changes in frequency due to sudden changes in supply and demand.

In the majority of situations, changes in supply or demand are such that variations in frequency are very small. Household lighting, televisions and washing machines being switched on and off are all examples of minor changes in demand that occur continuously and that change the frequency of the power system. In response to these small changes in frequency, power stations shift output ever so slightly to compensate, thereby maintaining the frequency within normal operating levels.

However, there are occasions when changes in supply and demand can be more substantial. Large generating units and transmission lines may suddenly stop producing or transmitting electricity, and large industrial facilities may suddenly stop consuming. These are referred to in the NER as contingency events. They are less common and result in more significant changes in system frequency.

Drivers of the rate of change of frequency

Whether the system frequency is rising or falling depends on the balance between generation and load. Whenever total generation is higher than total electricity consumption the system frequency will be rising and vice versa.

Managing frequency becomes more challenging when it is changing rapidly because there is less time in which to arrest the decline or rise before it strays beyond acceptable bounds.

The rate of change of frequency is proportional to the size of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs. The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change.

Box 2.1 sets out a detailed explanation of the relationship between the rate of change of frequency, contingency size, and system inertia.

Box 2.1 Determining the instantaneous rate of change of system frequency

The relationship between the instantaneous rate of change of system frequency, system inertia, and the size of the contingency is defined by the following equation.

$$\text{RoCoF} = (25 \times \Delta P)/I$$

Where

RoCoF = The instantaneous rate of change of frequency (Hz/second)

ΔP = The size of the contingency (MW)

I = Inertia (MW.seconds)

The instantaneous rate of change of system frequency is proportional to the size of the contingency and inversely proportional to the level of system inertia.

As an example, a large contingency event such as a non-credible double circuit failure of the Heywood Interconnector between South Australia and Victoria at a time of high power transfer would result in a high rate of change of frequency. The rate of change of frequency would be even higher if there are only a few synchronous generating units contributing inertia in South Australia at the time of the contingency.

Current arrangements for managing system frequency

To keep the power system in a secure operating state, the frequency must be controlled within a defined range. This range included in the Frequency Operating Standards (FOS), which sets out the range of allowable frequencies for the electricity system under different conditions, including normal operation, following contingencies, and during emergency situations.[11]

Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the FOS. AEMO is responsible for maintaining the system frequency within the bounds of the FOS.[12]

AEMO maintains the secure operation of the system by continuously monitoring the system frequency as it dispatches generation to meet consumer demand. Calculations on the level of generation to be dispatched are undertaken every dispatch interval to meet expected energy consumption over the next five minutes. There is a possibility in each five-minute dispatch interval that the level of actual energy consumption is different to what was anticipated. A substantial difference has the potential to result in a large shift in system frequency.

AEMO may restrict the operation of the power system to reduce the potential size of sudden changes in generation or load. AEMO continually monitors the system to determine the likely impact of the occurrence of the largest credible contingency and may limit flows on the network to reduce the potential size of the contingency, or the likely impact, should it occur.

In addition to constraining the system, variations in frequency are managed in the NEM through the procurement of Frequency Control Ancillary Services (FCAS). These services are provided by generators to control system frequency in response to supply or demand disturbances.

11 The Reliability Panel sets the level of the Frequency Operating Standards in consultation with AEMO. A review of the Frequency Operating Standards is undertaken by the Reliability Panel based on terms of reference received from the AEMC.

12 Clause 4.3 of the NER

If the level of dispatched generation is significantly below the level of energy consumption, the shedding of load may be required to keep the frequency within the limits of the FOS. Under the NER arrangements, AEMO is obliged to return the power system to a satisfactory operating state following any contingency event, including all non-credible contingency events.[13] This may include restoring the power system following a range of different events, including the loss of interconnection between two regions to the simultaneous trip of every generating unit within a region.

In any instance that the level of dispatched generation is different to total energy consumption, the rate that the frequency changes will be determined by the size of this difference and the level of system inertia. The lower the system inertia, the greater will be the rate of frequency deviation in response to a given change in supply or demand, and the greater will be the requirement for FCAS to revert the system frequency to normal operating levels.

AEMO procures FCAS to maintain system frequency within the limits of the FOS by ensuring that total generation matches total demand in real time. FCAS is used to meet the FOS under normal system operating conditions and in response to credible contingency events. Under multiple contingency events and non-credible 'separation' events, the under-frequency load shedding (UFLS) scheme is used to prevent the system frequency from breaching the extreme frequency excursion tolerance limits, which define the maximum boundaries of the FOS.[14] Outside of these limits, there are no obligations on generators or loads to remain connected to the system. The UFLS is used as a last resort to minimise the impact of major disturbances in the system to prevent the occurrence of wide ranging blackouts.

Frequency control ancillary services

FCAS is currently divided into two components – regulation and contingency. Regulation FCAS is used to control system frequency in response to minor variations in supply and demand during the dispatch period. Contingency FCAS is used to control frequency in response to major variations in frequency caused by contingency events such as the loss of a generating unit or a significant transmission line. Contingency FCAS acts to arrest steep rates of change of frequency and then stabilises and recovers the system frequency over time to bring it back to within the normal operating frequency bands.

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13 This obligation is established in various NER powers and the Frequency Operating Standards. This includes clause 4.3.2, which places an obligation on AEMO to achieve the AEMO power system security responsibilities in accordance with the power system security principles. NER clause 4.2.6(c) then sets out these principles, which includes a requirement that adequate load shedding facilities initiated automatically by frequency conditions outside the normal operating frequency excursion band should be available and in service to restore the power system to a satisfactory operating state following significant multiple contingency events. The FOS also require AEMO to maintain the frequency of the power system within the extreme frequency excursion tolerance limits, for any multiple contingency event.

14 A multiple contingency event is defined in the FOS as either a contingency event other than a credible contingency event, a sequence of credible contingency events within a period of five minutes, or a further separation event in an island.

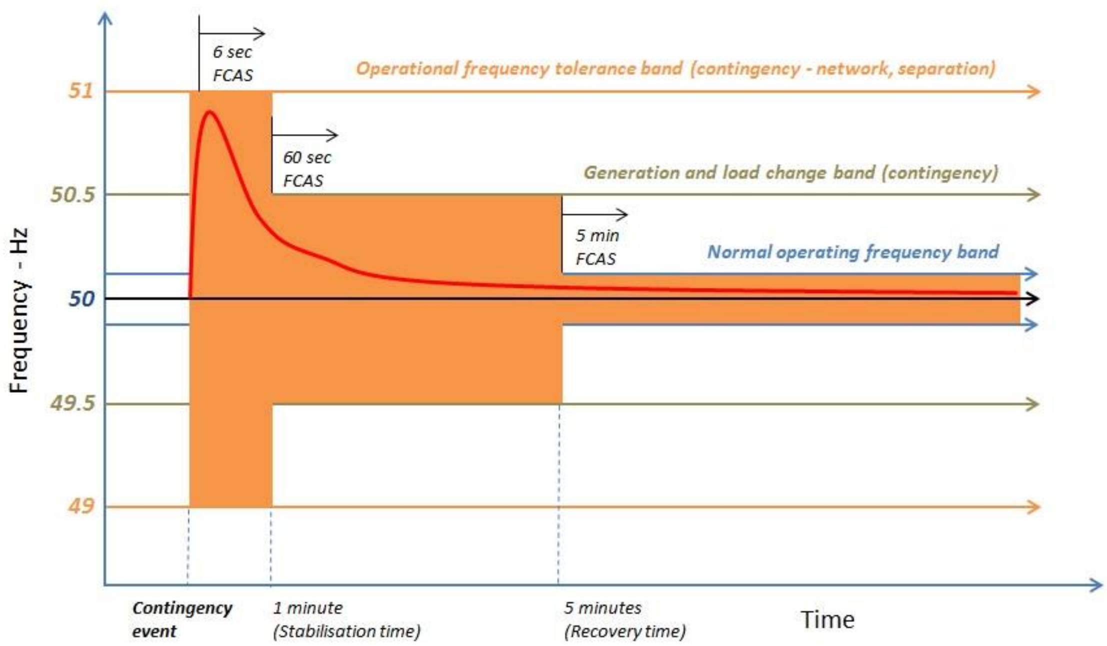
AEMO coordinates regulation FCAS provided by market participants through its central dispatch process. AEMO continually monitors the electricity system through the Automatic Generation Control (AGC) system and sends control signals to the generators providing regulation FCAS to adjust output in response to minor changes in system frequency. There are two regulation FCAS markets – one to correct a minor drop in frequency (raise) and the other to correct a minor rise in frequency (lower).

Contingency FCAS is coordinated locally by generators in response to larger frequency deviations that occur following contingency events. These local technologies are designed to detect and respond to frequency deviations and include generator governor responses, load shedding, rapid generation response, and rapid unit unloading.

There are six contingency FCAS markets – six-second markets, 60-second markets, and five-minute markets for both raise and lower services. The six-second services are used to arrest major changes in frequency following a contingency event. The 60-second services are used to stabilise frequency. The five-minute services are delayed responses used to recover frequency to normal operating levels following a major change in frequency.

Figure 2.2 shows how contingency FCAS operates to control frequency deviations following a credible contingency event. In this example, a contingency event based on a sudden large loss of load to the system results in an excess of generation and a steep increase in system frequency. The six-second contingency FCAS response is used to arrest the frequency excursion before it exceeds the operational frequency tolerance band of 51 Hz. The 60-second contingency FCAS response stabilises the frequency, followed by the five-minute FCAS response to recover the frequency to within the normal frequency operating band.

Figure 2.2 Control of system frequency through FCAS



At any point in time, the steepness of the frequency curve represents the rate of change of frequency (RoCoF). As can be seen, the RoCoF is highest immediately following the occurrence of the contingency event.

Challenges of controlling system frequency in a low inertia system

A shift from synchronous generation to non-synchronous generation has the effect of reducing the level of system inertia. The lower the level of inertia, the higher the rate of change of frequency for any given change in supply or demand. The task of controlling frequency within the bounds of the FOS becomes more challenging for large changes to supply and demand.

An additional consideration is that most FCAS is currently provided by synchronous generators. As synchronous generators become more scarce, new sources of FCAS will need to be found for AEMO to be able to manage excursions in system frequency when they occur.

More rapid rates of change will also increase the importance of fast FCAS to control system frequency and maintain system frequency within the FOS. As this shift occurs over time, some circumstances may eventuate where the RoCoF is so high that contingency FCAS is insufficient for AEMO to keep the system frequency within the operating frequency tolerance band under normal market operations. This may occur because the speed of available contingency FCAS is too slow to arrest the frequency following a change in generation or load. The fastest response contingency FCAS operating within a six-second timeframe may not be able to arrest significant deviations in frequency occurring over timeframes less than one second.

If FCAS is insufficient to arrest the frequency change, AEMO would rely on the UFLS to control system frequency and avoid cascading generator tripping and system black outs.[15] However, it is also possible that the frequency sensing relays on existing emergency protection schemes may be too slow to respond in time to arrest the rate of frequency change.

Existing UFLS schemes utilise relays that detect a change in the frequency and open a circuit breaker to shed successive load blocks in a controlled manner. However, these relays have been designed to meet the historically slower RoCoF levels in the NEM. It may be that the rate of the change of frequency is far too high for these existing relays to arrest the fall in frequency before the FOS are breached.

The capability of emergency protection schemes to control system frequency is the subject of two rule change requests submitted by the South Australian Minister for Mineral Resources and Energy. In accordance with statutory timelines, draft determinations on these two rule change requests are expected to be made on 22 December 2016.

The ability of generators to remain connected to the power system through periods of high frequency change also affects the ability to control system frequency within the

15 Only applies to under-frequency events.

bounds of the FOS. Standards on the ability for generators to ride through changes in system frequency are set out in connection agreements.[16] Only generators that have connected since 2007 have been required to meet these standards.

The automatic access standards currently require generating units to withstand a RoCoF of 4 Hz per second for 0.25 seconds.[17] Generators may negotiate a lower access standard. However, the minimum access standards require generating units to remain connected through an event where RoCoF reaches up to ±1 Hz per second for more than one second.[18] There is no obligation on generators to remain connected to the system through an event where the RoCoF exceeds these levels, even if the system frequency remains within the bounds of the FOS. As system inertia reduces, conditions may arise where the RoCoF exceeds ±1 Hz per second, which may result in generators being inadvertently disconnected from the electricity system.

Disconnection of synchronous generators may further increase the RoCoF (for under-frequency events) and make it more difficult for the remaining generators to stay connected, particularly in cases where the generators that disconnect first are contributing to system inertia. In this manner, a system disturbance that results in a high RoCoF could very quickly result in cascading tripping of generators.

AEMO has an obligation to operate the power system within the bounds of the Frequency Operating Standards and can put in place security constraints to manage RoCoF in order to remain in a secure operating state. AEMO may direct generators to change output in the interests of system security. However, directions to generators by AEMO are made irrespective of economic considerations and the calculation of the optimal economic dispatch.

There are currently no market or regulatory mechanisms for generators to supply, or for AEMO to acquire, inertia or fast response frequency control services to limit the rate of change of frequency.

The FCAS provided by synchronous generators is usually not faster than a few seconds. Inverter based generators, such as wind and PV, may have the potential to provide a much faster FCAS response. As part of its FPSS work program, AEMO is investigating the capabilities of different technologies to provide fast frequency response services.

16 Generators may elect to meet the more stringent automatic access standards or may attempt to negotiate a lower level of access with their NSP. Generators are not permitted to negotiate a level of access lower than the minimum access standard.

17 Schedule 5.2.5.3(c) of the NER. This only applies to generators post 2007.

18 Schedule 5.2.5.3(b) of the NER. This only applies to generators post 2007.

2.3.2 Managing power system strength

System strength

System strength is an inherent characteristic of a power system and it relates to the size of the change in voltage as a result of a change to the load (or generation) at a connection point. When the system strength is high at a connection point the voltage changes very little for a change in load, however, when the system strength is lower the voltage would vary more with the same change in load.

System strength is also often referred to as fault level. The fault level is the magnitude of the abnormally high current that flows when an item of electrical equipment is damaged, or when lightning or bushfire smoke causes an arc between conductors on an over-head line. In these instances, a large fault current will flow into a fault on a strong system, while a relatively low fault current will flow into a fault on a weak system.

Contributions to the strength of the system come from the synchronous generating units in the power system, with little or no contributions from non-synchronous generation.[19] Thus the system strength depends on the number of synchronous generating units operating near the connection point and the degree to which these units are electrically linked to the connection point.

Current and potential future issues with managing system strength

Historically, high fault levels in the NEM have been a concern. This is because load growth leads to new generation being installed. There is a risk that the resulting fault currents can exceed the ratings of the network components, particularly the circuit breakers that are required to interrupt the fault current, potentially damaging equipment.[20] High fault levels can be managed through restrictions placed by AEMO on some generation and the network configuration. However, recently the system strength has been reducing in some parts of the NEM power system as a number of synchronous generating units have been exiting the market and the new generating units that replace them are non-synchronous, and thus don't contribute as much to system strength.

AEMO has identified a number of technical issues associated with low system strength[21] and these issues have been discussed in the South Australian Government's

19 Modern inverter connected generating units (such as type 4 wind farms, battery storage and solar) can be made to provide some fault current. However, the majority of these inverters shutdown during a fault and do not provide a contribution to the fault current.

20 Circuit breakers are the large switches in the network used to disconnect and re-connect system equipment such as lines, cables, transformers, generating units and customer loads. These circuit breakers need to have the capability to disconnected equipment, even when a large fault current is flowing. A circuit breaker is likely to explode if it attempts to open when the fault current exceeds its rating.

21 AEMO, *Future Power System Security Program - Progress Report*, August 2016, p. 45.

rule change request on the management of power system fault levels.[22] These issues include:

- reducing the effectiveness of the protection systems used by the network businesses, generators and large customers, thus potentially requiring the replacement or readjustment of the affected protection systems;
- increasing the difficulty for the network businesses to maintain stable voltages; and
- reducing the ability of inverter connected generating units (such as modern wind, solar PV, battery storage) to operate continuously following a major fault or disturbance to the power system, potentially meaning that some existing generating units are no longer able to meet their generator performance standards under all conditions.[23]

The rules do not provide mechanisms to manage a reduction in the strength of the system. In particular, no entity is responsible for maintaining the system strength at a connection point and there are no system standards for system strength because it varies significantly throughout the power system and under different conditions. Also, the rules are not explicit as to whether a generator is required to modify its generating units if they no longer comply with the technical standards at the reduced system strength.[24]

22 Minister for Mineral Resources and Energy (South Australia), *Rule change request – Managing Low Power System Fault Levels*, 12 July 2016, p. 1.

23 Generators are required to meet the technical performance requirements in Schedule 5.2 of the rules, which include requirements to ride through system faults. Generators negotiate the required technical performance at the time of their connection, based on the power system information that is available at that time. The negotiated performance is registered with AEMO, who use this information when managing the security of the power system. The generators must develop an ongoing compliance program to ensure ongoing compliance with their technical performance is maintained and the AER performs audits on selected generators.

24 This question may have been addressed in the confidential connection agreement between the generator and associated network business. However, this would not be sufficient to address the issues over the long term.

3 Technical solutions to address system security

Determining the appropriate form of any potential changes to regulatory frameworks requires an understanding of the possible technical solutions. The control of system frequency is influenced by three related factors, including the initial rate of frequency change, the capacity to return the system to stability, and the ability of generators and loads to withstand the frequency change.

The initial rate of change of frequency following the occurrence of a contingency event is influenced by the level of inertia in the system and the size of the contingency. One option to limit the rate of frequency change is to introduce additional constraints that alter the operation of the power system. The application of constraints on the power system is a tool already available that can be used to limit the size of potential contingencies.

However, constraining the operation of the system has an associated cost as it may restrict power being sourced from the lowest priced generation. An alternative to constraining the system would be to increase the level of inertia. In practice, increasing the level of inertia could involve increasing the number of synchronous generating units online or constraining off devices that do not provide inertia. Additional devices that provide inertia to the system could also be installed.

Inertia does not act to arrest the frequency change entirely or revert the frequency back to normal operating levels. A faster response service than is currently available is likely to be required to manage future potential disturbances to the power system. This may include the creation of a mechanism to obtain fast frequency response services that operate within a shorter timeframe than the current fastest FCAS specification of six seconds, as well as schemes that are effective in the emergency shedding of load or generation.

The decision to obtain inertia or fast frequency response services from a particular generator must also consider the tolerance of that generator to sudden high rates of change of system frequency. Generators that trip as a consequence of high rates of frequency change may exacerbate the disturbance to the system by both contributing to the overall size of the contingency as well as reducing the level of inertia in the system.

A potential complementary measure to constraining the system or increasing the levels of inertia would be to impose additional obligations on generators to design plant to be able to tolerate higher rates of frequency change. EirGrid in Ireland has recently proposed to increase the requirements on generators to be able to ride through periods of high rates of frequency change. The adoption of a similar approach in the NEM may be an option to assist in the management of system frequency following disturbances.

When assessing the different potential options for the provision of inertia for the management of frequency, it is important to also consider the impact on system strength. The number, size and location of synchronous generators and synchronous condensers determine the ability to manage both frequency and system strength.

This chapter sets out further detail on the potential technical solutions to the issues of managing frequency in a low inertia system. The inter-relationships with issues associated with low system strength are also discussed.

3.1 Three aspects to managing frequency in a low inertia system

Challenges in the management of system frequency have emerged due to the decline in inertia as the quantum of synchronous generation has reduced. However, a lack of inertia is not a problem in itself. Rather, the emerging issue is the increased difficulty in controlling the system following the occurrence of a large contingency.

There are three related factors that influence the ability to maintain control of the system following a contingency:

1. The initial rate at which the frequency is changing, influenced by the size of the contingency and the level of system inertia.

2. The capacity to return the system to stability, through the shedding of generation or load, or the intervention of other frequency response services.

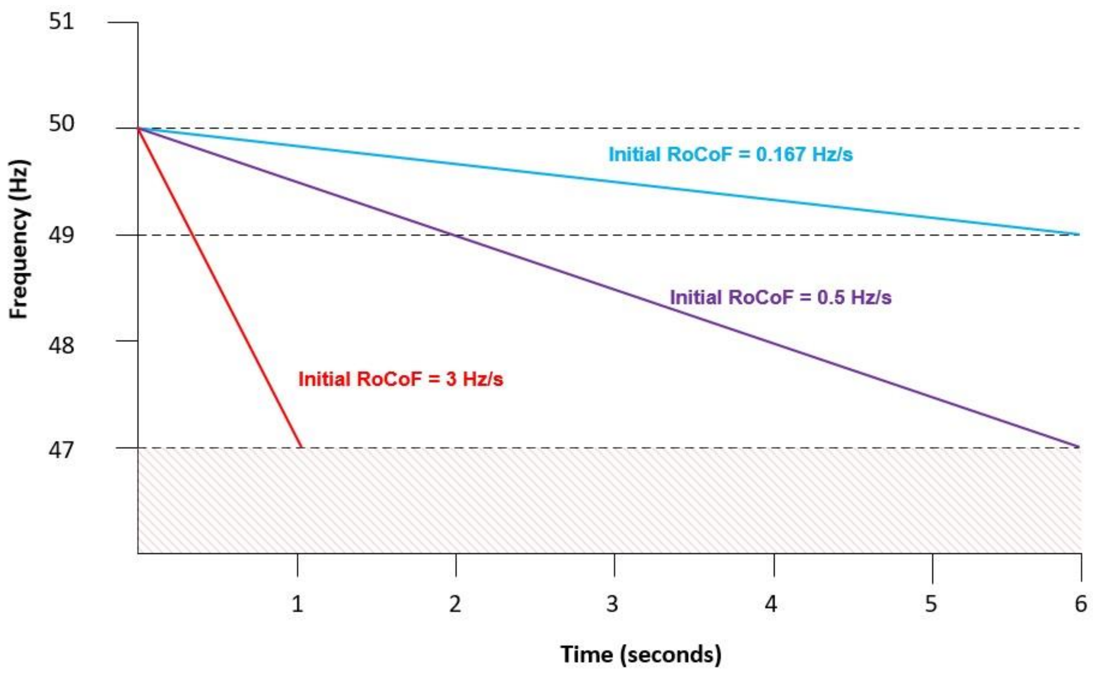
3. The ability of generators and loads to withstand or 'ride-through' changes in frequency.

3.2 Initial rate of change of frequency

The instantaneous rate of change of frequency following the occurrence of a contingency event is influenced by the level of inertia in the system and the size of the contingency. The speed at which the frequency changes determines the amount of time that is available to arrest the decline or increase in frequency before the frequency moves outside of the fixed bounds of the FOS.

Figure 3.1 illustrates how the rate of frequency change determines the amount of time available to respond. The three lines in the figure show the potential impacts on the level of frequency from different levels of initial RoCoF. The figure assumes that a loss of generation occurs with the system frequency at 50 Hz, there are no available services to arrest the decline in frequency until six seconds after the contingency (the point at which the six second FCAS responds), and all units in the system can tolerate the system conditions prior to restoration of the system frequency.

Figure 3.1 Initial RoCoF determines the time available to respond



- For the frequency to remain within the operational frequency tolerance band (above 49 Hz), the initial RoCoF cannot exceed 0.167 Hz/s (blue line)
- For the frequency to remain within the extreme frequency excursion tolerance limits (above 47 Hz), the initial RoCoF cannot exceed 0.5 Hz/s (purple line)
- An initial RoCoF of 3 Hz/s would lead to the frequency falling below the extreme frequency excursion tolerance limit after one second (red line).

In addition to showing the frequency implication of the initial RoCoF, figure 3.1 also highlights the challenges posed by the high levels of RoCoF that are now possible in certain parts of the NEM, most notably South Australia.

Prior to the occurrence of a contingency event, there are two ways to minimise the resulting initial RoCoF:

- constrain the power system to minimise the size of the contingency; and/or
- increase the level of inertia in the system to resist the initial frequency change.

3.2.1 Constraining the power system

There are numerous constraints that feed into the dispatch engine including, amongst others, generator capacity, thermal ratings on transmission lines, operating limits of interconnectors, ramp rates and dispatch inflexibility profiles of thermal units, and FCAS requirements.

One option to address system security is therefore to introduce additional constraints that alter the operation of the power system. Such constraints would limit the maximum contingency size, for a defined set of contingencies, at any one point in time, relative to the amount of inertia online. The constraints may have the effect of:

- reducing flows on specific interconnectors;
- dispatching generators out of merit order; and
- constraining off specific generators that may be unable to tolerate certain system conditions.

The introduction of a binding constraint into the dispatch engine may act to increase dispatch prices. This change in prices is the result of addressing the specific system security concern through the dispatch process. For example, a constraint that restricts flows on an interconnector may limit the ability of power to be sourced from a lower priced generator in another region. The application of constraints on the power system is an immediately available tool that can be used to limit the size of contingencies. However, it has the potential to increase the costs of managing system security. These costs may be reduced through other mechanisms to obtain services that allow for alleviation of the constraint.

3.2.2 Increasing the level of inertia

An alternative to constraining the system to limit the contingency size would be to increase the level of inertia in the power system. A higher level of inertia would permit the occurrence of larger contingencies for a given level of initial RoCoF.

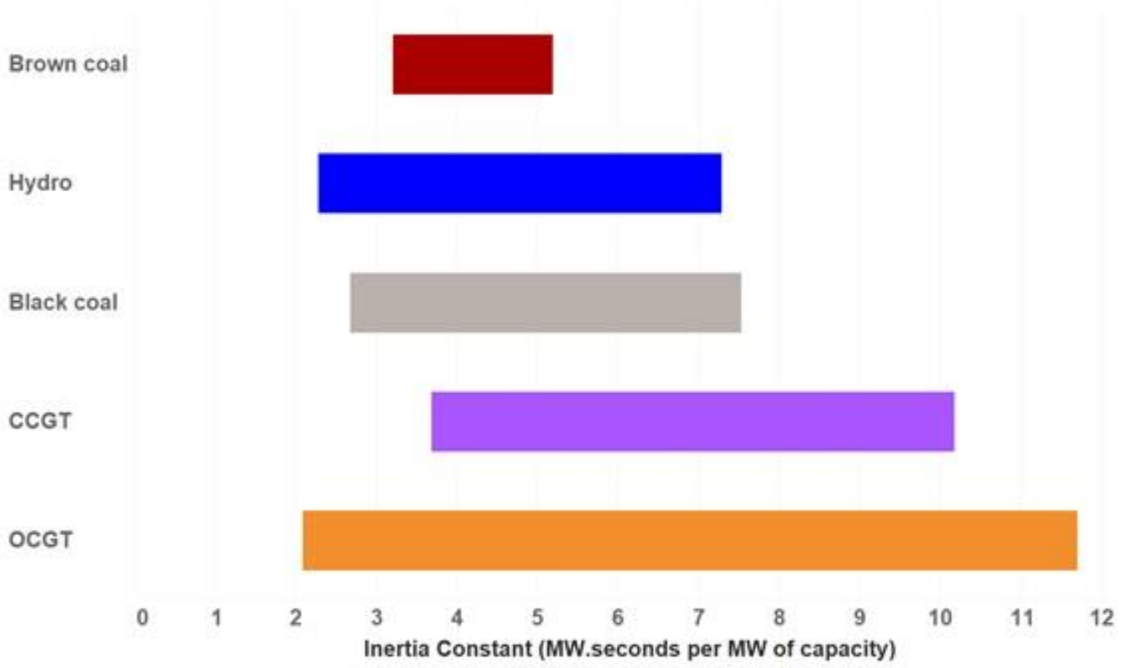
Inertia from synchronous generators

Inertia is provided by large spinning generators, such as open-cycle gas turbines or steam turbines powered by coal, gas, or solar thermal. The rotation of the turbines is synchronised to the frequency of the power system. The large mass of the turbines means that energy is required to either increase or decrease the speed of the rotation. As such, the turbines will tend to resist any changes in frequency across the system. The provision of inertia from a synchronous generator is binary in that it provides all of its inertia when online, irrespective of its generating output.

Newer types of electricity generators, such as wind and rooftop solar, are not synchronised to the grid, have low physical inertia, and are therefore currently limited in their ability to dampen rapid changes in frequency or respond to sudden large changes in electricity supply or consumption.

Figure 3.2 shows the levels of inertia provided by different synchronous generating technologies in the NEM. The inertia constant (MW.s per MW of capacity) varies across different technologies and between different generating units of the same technology.

Figure 3.2 Levels of inertia provided by different synchronous generating technologies in the NEM



The relationship between inertia and capacity is not uniform. Some generating units provide significantly more inertia per MW of capacity than other generating units.

Other sources of inertia

Inertia does not necessarily need to be provided by synchronous generating units. Synchronous condensers provide inertia to a system without producing energy. These are large synchronous machines similar to those used in synchronous generating units but they do not include a turbine to produce energy to be converted to electrical energy. Synchronous condensers are already used in the NEM to provide reactive power control and to increase the system strength in some transmission networks. Loads that include synchronous motors can also provide inertia to the system.

Inertia as a tool to manage frequency

As discussed, the level of inertia in the system determines the instantaneous RoCoF for a given contingency size. A greater level of inertia increases the time available to respond to a major disturbance. In practice, increasing the level of inertia could involve any combination of the following:

- Altering dispatch to increase the number of synchronous units online, and the amount of inertia that they provide to the system.
- Constraining off devices that do not provide inertia, so as to make room for units that do provide inertia.
- Installing devices (eg synchronous condensers) that provide inertia to the system without providing any energy.

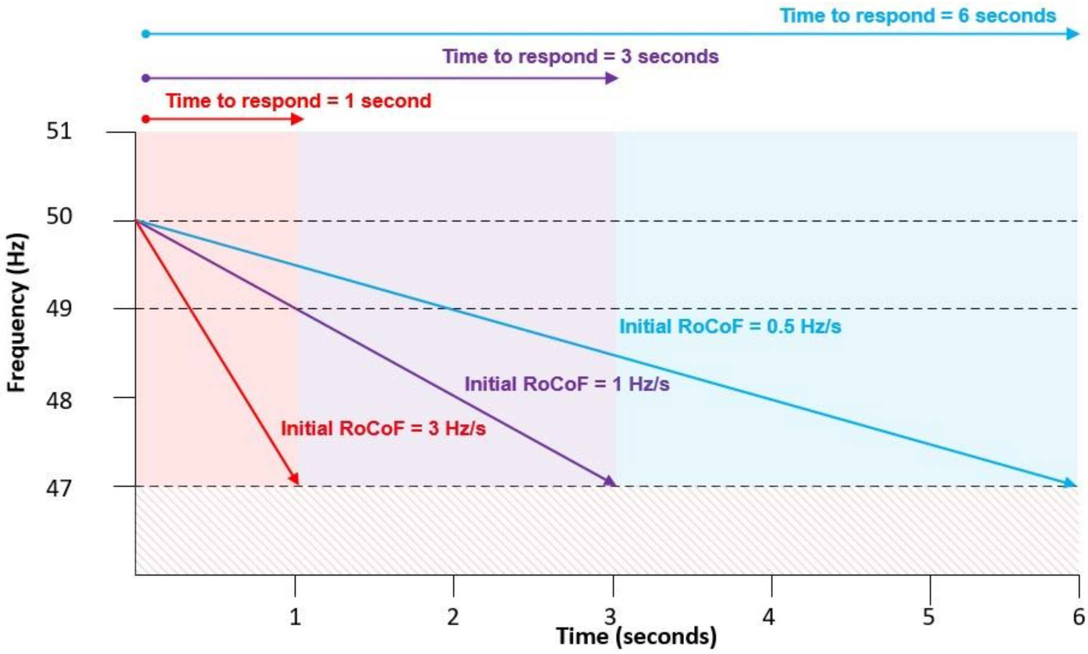
3.3 Capacity to return the system to stability

Limiting the initial rate of change of frequency only determines the amount of time before the frequency moves outside of the bounds of the FOS. Inertia does not act to arrest the frequency drop entirely or revert frequency back to normal operating levels.

A system with high levels of inertia but with no frequency control or ability to shed generation or load would merely see the frequency move outside of the bounds of the FOS more slowly. For example, an initial rate of change of frequency of 3 Hz per second requires a response within one second, otherwise the frequency will fall outside of the extreme frequency excursion tolerance limit. It follows that having capacity to restore frequency to its normal operating band, or at the very least to arrest a fall, is critical to ensuring stability of the system.

Moreover, the greater the capacity of a system to respond to frequency changes after a contingency event, the lower the need to limit the initial RoCoF. This relationship is illustrated in figure 3.3.

Figure 3.3 Initial RoCoF determines the length of time to respond



The figure shows that, in order to remain within the extreme frequency excursion tolerance limit of 47 Hz:

- an initial RoCoF of 0.5 Hz/s requires a response within six seconds;
- an initial RoCoF of 1 Hz/s requires a response within three seconds; and
- an initial RoCoF of 3 Hz/s requires a response within one second.

Given that the fastest contingency FCAS currently operate as six-second services, it appears that a faster response service is likely to be required to manage future potential disturbances to the power system. Following a contingency event, there are two principal means of returning frequency to its normal operating band within a timeframe less than six seconds:

- Creating a mechanism to obtain fast frequency response services that operate under six seconds.
- Schemes that are effective in the emergency shedding of load or generation.

3.3.1 Fast frequency response

As discussed, the level of inertia provided is an inherent physical property of the generating unit and acts to dampen changes in system frequency following a sudden shift in generation or load. This is different to frequency response services which involve a power injection following a change in frequency in order that the system frequency can be stabilised back to normal operating levels. As such, all frequency response services involve a time delay following the change in generation or load, with some response services being faster than others.

Currently, the fastest mechanism for the procurement of FCAS is based on a response time in the order of seconds. AEMO has identified that the future power system may require frequency response services that can be activated in milliseconds.

While synchronous generators currently provide the majority of six-second raise FCAS, it appears unlikely that the response time of these services could be shortened. It is possible that inverter based generators such as wind and storage could provide a much faster FCAS response. Load based resources also have the potential to provide a very rapid response.

Fast frequency response as a tool to manage frequency

Fast frequency response services are not a mature technology. There are limited examples of fast frequency response technologies being used to provide a contingency service in major power systems in the world. EirGrid in Ireland has recently implemented a FFR contingency service triggered by local frequency change.[25] This service is based on a response time of two seconds. However, this service faces challenges in relation to the robust detection and measurement of high RoCoF events.

Preliminary investigations by AEMO suggest that it is unclear the extent that fast frequency response services could be relied upon to prevent a system-wide blackout following a major disturbance to the system.

However, fast frequency services could increase the ability of the system to tolerate a major disturbance, and in turn increase the initial RoCoF that the system can withstand. It follows that fast frequency services have the potential to be an extremely valuable tool to manage system security, particularly where it is costly to constrain the system to limit RoCoF.

The Commission considers that a long-term solution to managing frequency in a low inertia system should anticipate, or at least not preclude, the potential use of fast-frequency response technologies.

Fast frequency response technologies

Fast frequency response is distinct from synchronous inertia. Technologies that provide inertia to the system act to immediately resist changes in frequency. Fast frequency response technologies involve a time delay between the initial change in frequency and the frequency response. This delay is comprised of four separate components which sum to equal the total time to respond:[26]

- **Measurement** – The change in frequency must be measured over a period of time in order to determine the appropriate response. An inaccurate measurement of the change in frequency has the potential to result in a frequency response that is

25 DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp 111-112.

26 DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp 60-62.

either insufficient to correct the frequency change or may overcompensate which may force the frequency to change in the opposite direction. Alternatively, a response could be inadvertently activated for normal deviations in frequency.

- **Signalling** – Measurement of the frequency change then needs to be communicated to the device providing the frequency response. This signalling may take time depending on the distance between the point of measurement and the device and the speed of the communications equipment being used.

- **Activation** – Once the device received the signal, it may then require time to activate the response. The length of the activation time depends on the power electronic converter being used and the type of FFR device behind the power electronic converter.

- **Ramping** – The final component of the response period is the time taken for the FFR device to ramp up from the point of activation to its maximum response output.

There are a number of options for technologies that may be able to provide the activation and ramping components of fast frequency response.

Wind

Wind generators are electrically decoupled from the frequency of the power system and use power electronics to allow for the speed of rotation of the blades to adjust to different wind speeds. The delivery of power to the grid is controlled through the power electronic device, which allows for near instantaneous adjustment of power output in real time. The mass of the rotating blades can be converted to electrical energy, which slows the speed of the blades.

Wind generators have the capability to rapidly respond to changes in system frequency with the ability to inject power up to 10% of their pre-disturbance output with a ramp rate of 20-30% of the maximum power injection per second. However, the ability to provide power injections following disturbances is usually dependent on voltage stability and a weak system may suppress the ability for wind generators to provide a frequency response.

Solar PV

Solar PV has the capability to provide a rapid power injection to respond to frequency changes. However, unlike wind generators that store energy in the rotating mass of the blades, solar PV converts solar energy directly to electrical energy and therefore must operate at a level below its maximum output in order to be able to provide a rapid power injection when needed.

Battery storage

Batteries involve the conversion of chemical energy into electrical energy as ions flow from one electrode to another through an electrolyte. Batteries have the potential to provide extremely rapid response times, operating in the order of tens of milliseconds. Some of the fastest response times require batteries to be maintained in a hot standby condition, which can result in energy losses and cycling of batteries can reduce the life of the device through use.

Supercapacitor energy storage systems have a higher cycle life and can be charged and discharged rapidly. However, they typically have lower stored energy than chemical batteries.

Load based resources

Interrupting a load to provide a frequency response service has the opposite effect on frequency as a generator rapidly increasing output to respond.

Controlled interruptible load is distinct from load shedding and may be able to participate in the provision of fast frequency response services. While response times on the order of milliseconds would likely require the shedding of load, response times of one second would allow for a more controlled reduction in load from participating facilities.

The provision of fast frequency response from loads would need to take into account the extent to which the load is also contributing to system inertia.

HVDC transmission

HVDC transmission links are able to regulate and rapidly change the volume and direction of power flow through programmable controls. This may have applications for the provision of fast frequency response services in regions where the tripping of AC connections to other regions may limit the level of available inertia.

3.3.2 Emergency frequency control

System frequency is primarily managed by FCAS. However, in some instances it may not be possible for the six-second contingency FCAS to respond quickly enough to keep frequency at acceptable levels. At this point, the remaining option to bring supply and demand back into balance is to shed load or generation. The shedding of load, or generation, is an emergency mechanism, intended to be used in the rare circumstance where a drop in frequency has not been arrested by FCAS.

Upon separation of South Australia from the rest of the NEM, under-frequency load shedding is activated to prevent the frequency from dropping below 47 Hz. This lower frequency standard was set as a result of the relatively expensive contingency FCAS available in South Australia.

In the NEM, load shedding occurs through the under-frequency load shedding (UFLS) scheme. The UFLS scheme typically comprises a series of relays linked to circuit breakers that are designed to disconnect load blocks at a predetermined frequency level. As the frequency drops, more and more load is disconnected to arrest the frequency decline. Once the frequency stabilises, FCAS can then be used to return the frequency to within normal operating bands. There is currently no equivalent set of arrangements in the NEM to manage over-frequency events.

Emergency shedding of load and generation as a tool to manage frequency

The shedding of load or generation is an emergency measure, acting as a last line of defence to control frequency. Nevertheless, the capability of the shedding scheme determines whether the system can withstand a disturbance, and so has consequences for the acceptable level of initial RoCoF.

The AEMC is currently considering two separate rule change requests from the South Australian Government that relate to:

- the arrangements that govern the operation of UFLS schemes; and
- the proposed introduction of an over-frequency generation shedding scheme.

The rule change requests seek to ensure that emergency frequency control schemes are fit for purpose, recognising the consequences of lower levels of inertia and the potential for high RoCoF.

3.4 Tolerance of the system

The decision to obtain inertia or fast frequency response services from a particular generator must consider the tolerance of that generator to sudden high rates of change of system frequency. For example, inertia that is obtained from a synchronous generator to prevent the RoCoF from rising above 2 Hz/s would not be effective if the RoCoF withstand capability of the generator was only 1 Hz/s. The implication is that inertia must be viewed in the context of the generator or other source that provides it.

The generator performance standards in relation to withstanding rates of change of system frequency are set out in schedule 5.2.5.3 of the NER. These standards have been imposed as a condition of generator connection agreements since 2007.

The automatic access standards require generating units to withstand a RoCoF of ±4 Hz per second for 0.25 seconds. Generators may negotiate a lower access standard, however, the minimum access standards require generating units to remain connected through an event where RoCoF reaches up to ±1 Hz per second for more than one second. There is no obligation on generators to remain connected to the system through an event where the RoCoF exceeds those levels, even if the system frequency remains within the bounds of the FOS. As system inertia reduces, conditions may arise where the RoCoF exceeds ±1 Hz per second, which may result in generators being inadvertently disconnected from the electricity system.

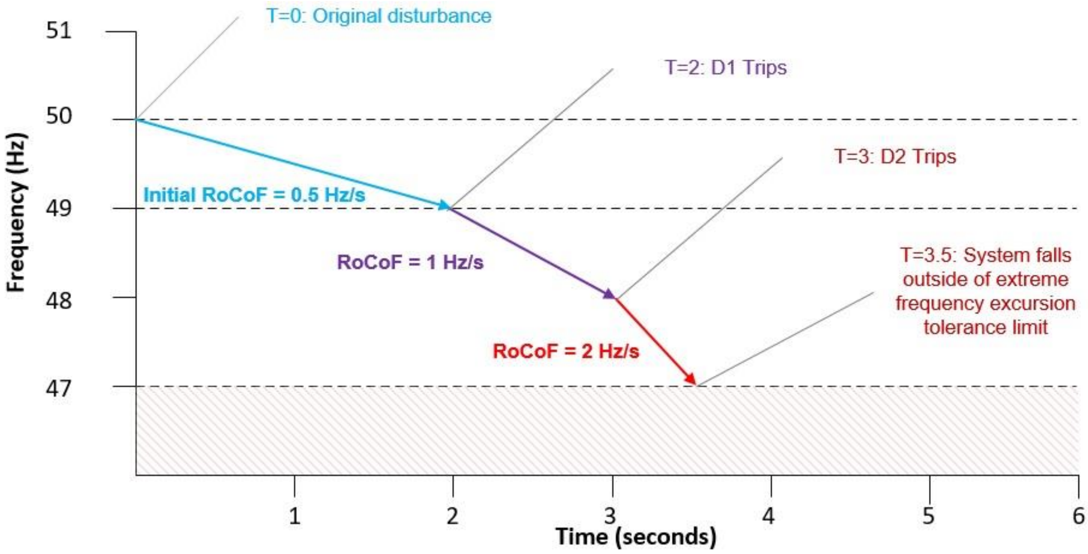
The withstand capability of generators that connected prior to 2007 is largely unknown. While historical incidents can provide some indication of the withstand capability of these generators, the capability of any particular generator to withstand high RoCoF is largely dependent on the operating and market conditions that were present at the time of the event.

Generators that trip as a consequence of high RoCoF may exacerbate the disturbance to the system and lead to an even higher RoCoF by both contributing to the overall size of the contingency as well as reducing the level of inertia in the system. This is illustrated in figure 3.4 which shows the effect of units tripping in response to a high RoCoF following a contingency. It is assumed that:

- one of the units online (D1) is unable to tolerate a RoCoF of greater than 0.5 hertz per second for more than two seconds; and
- one of the units online (D2) is unable to tolerate a RoCoF of greater than 1 hertz per second for more than one second.

Figure 3.4 shows how frequency may change over time as generating units trip, where the initial RoCoF is 0.5 hertz per second.

Figure 3.4 Effect of generating trips on system frequency



- At T=0 seconds, a contingency occurs, resulting in an initial RoCoF of 0.5 hertz per second.
- At T=2 seconds, the frequency has fallen from 50 hertz to 49 hertz, at which point generator D1 trips. The loss of D1 increases the RoCoF from 0.5 hertz per second to 1 hertz per second.
- At T=3 seconds, the frequency has fallen from 49 hertz to 48 hertz, at which point generator D2 trips. The loss of D2 again leads to a rise in the RoCoF from 1 hertz per second to 2 hertz per second.
- At T=3.5 seconds, the frequency has fallen from 48 hertz to 47 hertz and falls outside of the extreme frequency excursion tolerance limit.

This example demonstrates the importance of the ability of generators to ride through the disturbance. A single, large unit that cannot tolerate the conditions following a disturbance may act as a ‘weak link’. It follows that the system must be operated to account for the tolerance of the units that are online. This may mean:

- constraining off generating units with low tolerance to RoCoF;
- constraining the system or increasing the level of inertia to prevent the initial RoCoF from rising above a level that can be tolerated by all units;
- imposing additional obligations on generators to design plant with the capability to ride through periods of high RoCoF.

Generator obligation to ride-through high levels of RoCoF

A potential complementary measure to constraining the system or increasing the levels of inertia would be to impose additional obligations on generators to design plant to be able to tolerate high levels of RoCoF.

As discussed above, generators currently have obligations under their connection agreements to be able to tolerate maximum levels of frequency change over defined periods of time. The ability of AEMO to maintain system security under variable operating conditions may require a change to the minimum and automatic access standards to increase the capability of generators. These requirements are set out in schedule 5.2 of the NER.

However, the capability of a generating unit to ride through periods of high RoCoF does not solely depend on the physical characteristics of the plant. The RoCoF withstand capability of a generator is variable and can depend on:

- the output of the generator immediately prior to the contingency (a generator at full output is more likely to trip for a given RoCoF);
- the inertia provided by the generator (a generator providing high inertia would have lower withstand capability);
- the strength of the system (at low fault level, generators are more likely to trip for a given RoCoF); and
- the length of the RoCoF period (a longer period is more likely to cause a generator to trip).

EirGrid in Ireland has recently proposed to increase the requirements on new and incumbent generators to be able to ride through periods of high RoCoF.[27] The current capability of 0.5 hertz per second is to be increased to 1 hertz per second on the condition of technical assessments confirming that system security will be maintained.

The adoption of a similar approach in the NEM may be an option to assist in the management of system frequency following disturbances.

27 DGA Consulting, *International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator*, 14 October 2016, pp 23-24.

3.5 Consequences of solutions for system strength

In addition to reducing system inertia, the reduced number of synchronous generating units has meant that the system strength in some areas of the NEM power system has also decreased. System strength, also known as fault level, is a measure of the power system's ability to maintain the voltage with changes to the power flows in the system.

The system strength is measured in MVA and is defined as the product of the normal system voltage at a connection point and the current that would flow into a fault at the connection point. The strength of the system at a particular location depends on:

- the number and size of the synchronous generators and synchronous condensers in the vicinity; and
- the extent to which that location connects to the rest of the network.

Historically, the primary concern has been that system strength may be too high such that fault currents may damage equipment. This is because networks have been reinforced and additional generation was installed as the demand for electricity increased. This can potentially become a problem when the current that flows into a fault in the system exceeds the capability (or rating) of the network elements, in particular the circuit breakers. The rules require AEMO and NSPs to monitor the fault levels when operating and planning the power system to prevent the system strength exceeding the capability of the network components.

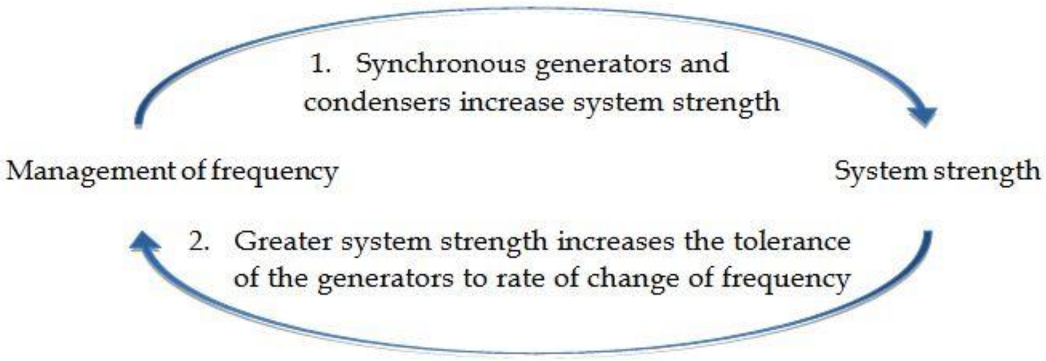
More recently, system strength in some parts of the power system has been decreasing as the number of traditional synchronous generators are operating less or being decommissioned. This is anticipated to cause a number of issues, including a reduction in:

- the capability of some transmission and distribution network protection systems, which rely on a high fault current, to operate effectively;
- the ability of network operators to manages voltages within their networks; and
- the ability of generators to operate correctly such that they can meet their technical performance standards, which can increase the risk of cascading outages leading to major supply disruptions.

Interactions between frequency management and system strength in low inertia power systems

The number, size and location of synchronous generators and synchronous condensers determine the ability to manage both frequency and system strength. Increasing the quantity of synchronous generation and synchronous condensers both provides inertia to assist in the management of frequency and increases system strength.

Therefore, when assessing the different potential options for the provision of inertia for the management of frequency, it is important to also consider the impact on system strength. The following figure shows the two main interactions between frequency management and system strength.



1. System strength is higher in the vicinity of the synchronous generators or synchronous condensers that provide inertia. As such, the provision of inertia may need to be distributed across the power system in order to prevent system strength being too high or too low in any particular location.

2. System strength is a determining factor in the ability of a generator to ride through periods of rapid change in system frequency. As the system frequency changes the speed of rotation of the synchronous generator must also change. This requires a high power flow into or out of the generator. If this power flow is too large, the generator may lose synchronism with the system and may disconnect.

4 The costs of managing system security

System security is necessary for the efficient functioning of the power system and benefits all market participants as well as the wider community. However, there are costs associated with maintaining the power system in a secure operating state.

Costs may arise from the need to avoid or minimise the impact on the system should network or generation elements suddenly fail. The application of limits on transmission lines, constraints on the output from generators, and the use of frequency response services are all examples of the operational costs incurred in maintaining a secure power system.

There are also costs associated with the failure to maintain a secure system. This may include damage to equipment, lost production, and the process of restoring the system.

Decisions in relation to the level of costs that should be incurred to avoid or minimise the level of costs from a system security incident are undertaken by the Reliability Panel through the determination and application of system security standards. AEMO makes operational decision within the bounds of these standards, which also have a bearing on the overall costs of managing system security.

The Reliability Panel sets the Frequency Operating Standards, which defines the range of allowable frequencies for the electricity power system under different conditions. The Reliability Panel's determination on the level of the frequency operating standards is guided by the physical capabilities of the power system but also represents a decision on the likely level of costs to consumers associated with disruptions to supply that is deemed acceptable given the likely costs that would be required to manage the electricity system to meet the standards.

AEMO makes operational decisions around how best to meet the Frequency Operating Standards set by the Reliability Panel. Each of the operational decisions made by AEMO has an associated cost which adds to the overall cost of maintaining a secure power system.

Currently, AEMO has the power to procure FCAS or constrain the system to limit the impacts in the event of a credible contingency but must rely on emergency protection schemes to control frequency in response to non-credible contingencies.

AEMO also has the power to reclassify non-credible events as credible events under abnormal operating conditions. Reclassification as credible permits AEMO to actively manage the system to avoid the need for emergency frequency control schemes and limit the consequences that might result from the occurrence of the particular contingency event. However, this reclassification has the potential to come at significant additional cost as a result of the system constraints imposed.

The Commission is considering whether there are some non-credible contingencies where the likelihood is sufficiently high, and the consequences of it occurring sufficiently detrimental, that it may be appropriate to constrain the system or obtain additional services to manage system stability. The new category of contingencies would permit AEMO to limit the rate of frequency change by constraining the system so that the under-frequency load shedding scheme would be effective.

The Commission is seeking to determine whether the categorisation of these events would be a role best suited to AEMO and also whether there would be any additional value in the Reliability Panel imposing additional standards for this category of events. These standards may define the acceptable level of consequences following the occurrence of the event or other ex-ante limits on the operation of the power system, such as a limit on the rate of change of frequency.

These standards may have a role to play in determining the required level of inertia to maintain system security, which can be divided into two components:

1. System security – the minimum level of inertia required to maintain the secure operation of the system.
2. Energy cost reduction – Additional inertia that lowers the overall cost of energy provision by allowing for the alleviation of constraints on the system.

4.1 Current costs of managing system security

A trade-off exists between the level of costs that should be incurred in avoiding or minimising the impact on the system, should a disturbance occur, and the probability of the level of costs that would likely be incurred as a result of the failure to maintain the system in a secure operating state.

Costs of avoiding or minimising the impact on the system may include the application of limits on transmission lines or constraining off generation to limit the size of the impact should these generation or network elements suddenly fail. It may also include the up-front costs of enabling the provision of frequency response services to stabilise the system should a supply disruption occur.

Costs incurred as a result of the failure to maintain the system in a secure operating state may be more varied and include such things as damage to equipment, the opportunity costs of lost production, and the additional costs of restoring the system. Depending on the extent of the failure, other societal costs may also be incurred.

The costs incurred in avoiding or minimising the impact of the contingency can be estimated up front. However, the costs incurred as a consequence of the failure of the system are wide-ranging and cannot be known with certainty until the event happens. As such, there is a range of potential outcomes which must be assigned a probability in order to evaluate the level of up-front costs that should be incurred.

Risk allocation and the accountability for investment decisions should rest with those parties best placed to manage them. Under a centralised planning arrangement, risks are more likely to be borne by customers. Solutions that allocate risks to market participants, such as businesses who are better able to manage them, are preferred where practicable.

Decisions in relation to the level of costs that should be incurred to avoid or minimise the level of costs from a system security incident are currently undertaken by the Reliability Panel through the determination and application of system security standards. AEMO makes operational decision within the bounds of these standards, which also have a bearing on the overall costs of managing system security.

4.1.1 Role of the Reliability Panel

The Reliability Panel sets the Frequency Operating Standards, which defines the range of allowable frequencies for the electricity power system under different conditions, including normal operation and following contingencies. Generator, network and end-user equipment must be capable of operating within the range of frequencies defined by the FOS, while AEMO is responsible for maintaining the frequency within the ranges defined by these standards.

The Reliability Panel's determination on the level of the frequency operating standards is guided by the physical capabilities of the power system but also represents a decision on the likely level of costs to consumers associated with disruptions to supply that is deemed acceptable given the likely costs that would be required to manage the electricity system to meet the standards.

The trade-off between the costs of managing system security and the consequences arising from a power system incident is similar to the decision that the Reliability Panel makes in relation to power system reliability.

The Reliability Standard is the maximum amount of electricity expected to be at risk of not being supplied to consumers in a financial year. The standard is expressed as a percentage of the annual energy consumption for the associated regions. The standard, referred to as the maximum expected unserved energy (USE), is 0.002% of annual energy consumption. The NEM Reliability Standard is contained in the NER.[28] The Reliability Panel may submit a rule change request to the Commission to adjust to the NEM Reliability Standard. The decision on whether to change the level of the Reliability Standard rests with the Commission.

The standard applies to unserved energy that is associated with power system reliability incidents that result from credible contingencies.[29] It does not apply to multiple or non-credible contingencies.

4.1.2 Role of the market operator

AEMO makes operational decisions around how best to meet the Frequency Operating Standards set by the Reliability Panel. The rules permit different actions to be undertaken to either prevent or respond to events which may impact the security of the electricity system. These events are categorised into credible and non-credible depending on their likelihood of occurrence.

Currently, AEMO has the power to procure FCAS or constrain the system to limit the impacts in the event of a credible contingency but must rely on emergency protection schemes to control frequency in response to non-credible contingencies. Procuring FCAS and constraining the system tend to be higher cost measures that are more frequently employed due to the higher likelihood of the occurrence of the credible event. In contrast, the existing under-frequency load shedding schemes are used infrequently to prevent widespread blackouts. These schemes operate at lower cost due to the lower likelihood of the events they are protecting against.

28 NER, clause 3.9.3C

29 The Reliability Standard also applies to delays in the commissioning of generating units and transmission elements.

AEMO may also reclassify non-credible contingencies as credible under abnormal conditions, such as storms or bushfires.[30]

Each of the operational decisions made by AEMO has an associated cost which adds to the overall cost of maintaining a secure power system.

4.2 Extending the current framework for managing system security

All non-credible contingencies are treated in the same manner regardless of the likelihood of occurrence or potential impact on the system. However, there are some non-credible contingencies where the likelihood is sufficiently high, and the consequences of it occurring sufficiently detrimental, that it may be appropriate to constrain the system or obtain additional services to manage system stability. The sudden non-credible loss of the Heywood Interconnector between South Australia and Victoria may be one such event.

4.2.1 A new category of event

The separation of South Australia from the remainder of the NEM may currently be classified as either a credible or non-credible contingency. A credible contingency would be the loss of a single circuit of the Heywood Interconnector with one line already out of service or the loss of both circuits when this has been reclassified as credible due to abnormal conditions such as bushfires in the vicinity of the lines. A non-credible contingency would the direct simultaneous tripping of both lines or the consequential over-loading and simultaneous tripping of both lines due to other contingencies in the network, such as multiple generating unit trips.

While a sudden and unexpected failure of both lines simultaneously is currently considered a non-credible contingency under normal system conditions, the fact that both lines are physically located on the same transmission tower suggests that it is not outside the realms of possibility that a double circuit failure could occur.

AEMO analysis shows that the loss of the Heywood Interconnector can lead to high RoCoF values when the level of inertia in South Australia is relatively low and the interconnector flow being interrupted is relatively high.[31] If the value of the RoCoF is high enough, the under-frequency load shedding scheme will be too slow to prevent a blackout.

Therefore, it may be desirable for the non-credible loss of the Heywood Interconnector to be classified as a new category of event. This new category, referred to as protected events, would permit AEMO to limit the RoCoF by constraining the system so that the under-frequency load shedding scheme would be effective.

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30 NER, clause 4.2.3A.

31 AEMO, *Future Power System Security Program – Progress Report*, August 2016, p. 21.

Currently, AEMO is permitted to reclassify non-credible events as credible events under abnormal operating conditions. Reclassification as credible permits AEMO to actively manage the system to avoid the need for emergency frequency control schemes and limit the consequences that might result from the occurrence of the particular contingency event. However, this reclassification has the potential to come at significant additional cost as a result of the system constraints imposed.

In contrast, categorisation of a non-credible event as a protected event would not require AEMO to actively manage the system to avoid the use of emergency frequency control. AEMO would be required to manage the system but only to the limited extent that the emergency frequency control schemes could operate effectively.

The non-credible loss of the Heywood Interconnector is one example of a contingency that may be classified as a protected event. Other possible contingencies are likely to exist elsewhere in the NEM which may also be classified as protected events. Allocation of individual contingencies to the protected events category would require an understanding of how the system should be operated to manage the occurrence of the event. The most appropriate entity to decide on the specific contingency events to allocate to this category is likely to be AEMO.

4.2.2 Setting new system security standards

In addition to the categorisation of protected events, standards may also be set in relation to system operation and the acceptable level of system impacts associated with each protected event. The most appropriate entity to undertake this role is likely to be the Reliability Panel.

For each protected event, the Reliability Panel may set a standard that defines the acceptable consequences following the occurrence of a protected event. This may include such items as a maximum level of load shedding in the region in which the protected event occurred and/or a maximum period of time following the occurrence of the event for generation and load to be reconnected.

A further possibility is that the Reliability Panel may also set ex-ante limits on the operation of the power system to control system frequency. For each protected event, the Reliability Panel may set a limit on the level of RoCoF to which AEMO must manage the system. This option was proposed as part of the rule change request from the South Australian Minister for Mineral Resources and Energy.[32]

The benefits of applying a limit on RoCoF is that it would provide a means to determine the extent to which the system should be constrained for a given contingency event. As an alternative to constraining the system, it would also act as a guide for the required level of inertia. Inertia would limit the size of the RoCoF that would result from the contingency and increase the likelihood that generators would be able to withstand the change in frequency and that the under-frequency load

32 South Australian Minister for Mineral Resources and Energy, *Managing the rate of change of power system frequency – rule change request*, 12 July 2016, p. 2.

shedding scheme would remain effective. As discussed in section 3.3, FFR may be used to arrest and stabilise frequency following the occurrence of a contingency and as such may reduce the level of inertia required in the system.

A limit on RoCoF would be applied in addition to the Frequency Operating Standards already set by the Reliability Panel. AEMO is currently required under the NER to manage the system within the bounds of the FOS. Given that the Reliability Panel would be guided by advice received from AEMO in relation to the tolerance of the system for different levels of RoCoF, a limit on RoCoF set by the Reliability Panel may be superfluous to the existing FOS. The advice provided by AEMO on an appropriate limit on RoCoF would likely be consistent with the requirement for AEMO to manage the frequency of the system within the bounds of the FOS.

The Reliability Panel setting the RoCoF limit upfront would likely be a conservative estimate so that the security of the system can be maintained under a worst case scenario. Permitting AEMO to vary operational arrangements for the management of system security may be more optimal as the tolerance of the system to RoCoF varies under different system conditions.

The Commission is seeking stakeholder views to determine whether the categorisation of events would be a role best suited to AEMO and also whether there would be any value in the Reliability Panel imposing additional standards for this category of events. This is also the subject of the Commission's draft determinations on the emergency frequency control rule change requests that are intended for publication on 22 December 2016 in accordance with statutory timelines.

4.3 Determining the level of inertia

The level of system inertia determines the size of the immediate RoCoF that would result upon the occurrence of a contingency of a given size. Limiting the size of the RoCoF would provide:

- a higher probability of generators remaining online following the occurrence of a contingency event;
- time for the under-frequency load shedding scheme to operate effectively; and
- time for frequency control ancillary services to respond and recover the frequency to normal operating levels.

Each of these aspects contributes to the system frequency remaining within the bounds of the Frequency Operating Standards.

The level of inertia that is required to maintain the RoCoF to a given limit can be divided into two components:

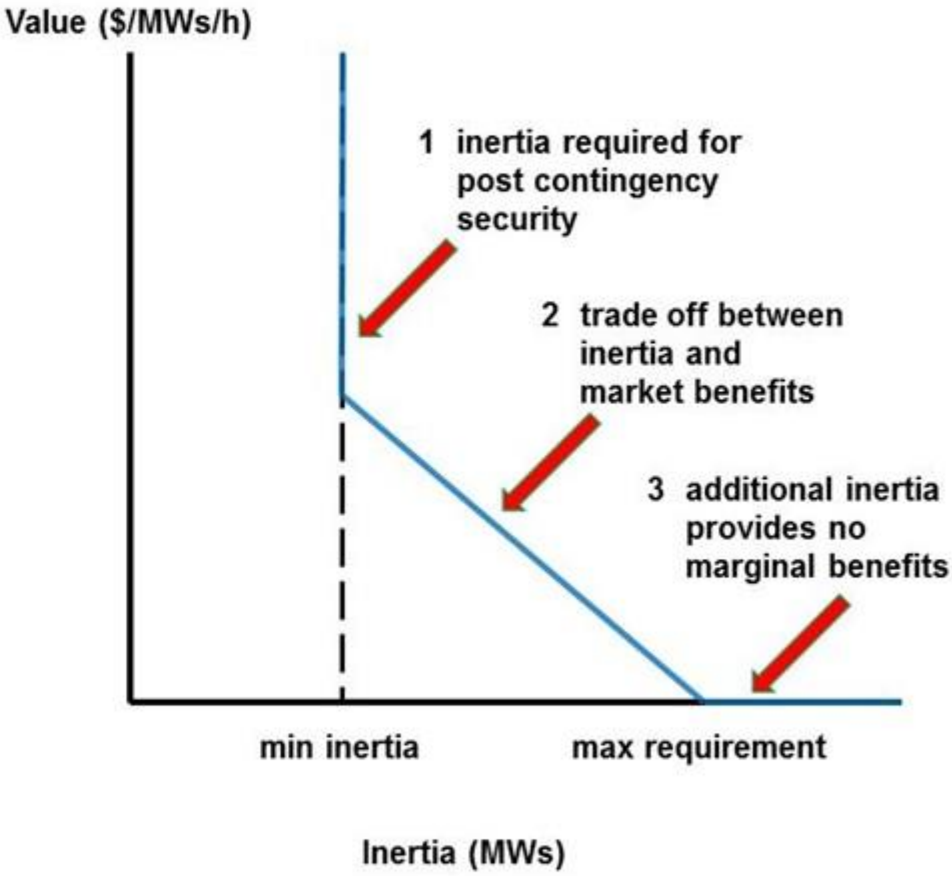
1. **System security** – The minimum level of inertia that is required to maintain the secure operation of the system. This minimum amount is required to limit the instantaneous RoCoF caused by a contingency in order to provide sufficient time

for a frequency response. This minimum amount would apply at a point in time but may vary depending on changes in market conditions, eg changes in the size of potential contingencies.

2. **Market benefits** – Additional inertia that lowers the overall cost of energy provision by alleviating constraints on the system. For example, in South Australia, this might involve a co-optimisation between obtaining additional inertia and constraining the Heywood Interconnector.

The split between these two components is illustrated in Figure 4.1, which shows a theoretical demand curve for inertia.

Figure 4.1 Value of inertia and the amount of inertia provided



The vertical line on the left represents the minimum quantity of inertia which is required for post-contingency security. This vertical line may shift to the left or right depending on the targeted RoCoF constraint but will be fixed for a given set of market conditions at a specific point in time. Beyond this level, the sloped line represents the trade-off that exists between the costs of supplying more inertia and other options for managing system security, such as constraining the system. A continuation of the line shows that any additional inertia supplied to the market has no effect in further alleviating constraints on the system and so provides no additional benefit for either maintaining system security or lowering the overall cost of energy production.

The distinction in the two components of inertia can be illustrated by using the failure of the Heywood Interconnector as an example. If the non-credible loss of the Heywood Interconnector was treated as a protected event then the system security component of inertia (vertical line) would be the minimum level of inertia required in the system and would determine the level of the instantaneous RoCoF should the interconnector trip with zero flow. This inertia would allow the frequency of the islanded region to be managed post-separation.

Any additional inertia above this minimum level (sloped line) would form part of the energy cost reduction component and would permit greater flows on the Heywood Interconnector. This would involve an economic trade-off between the costs of obtaining greater levels of inertia and the market benefits that could be derived from greater flows on the interconnector.

Once the maximum capability of the interconnector is reached, additional inertia does not provide any further market benefits (horizontal line). Obtaining additional inertia does not provide any ability to further increase flows on the interconnector.

5 Potential options to obtain additional system security services

Inertia and fast frequency response are distinct services which perform different roles in the management of system frequency. The Commission considers it probable that both these services are likely to be needed to manage the future security of the power system.

The Commission has developed a range of potential options for obtaining the required services.

1. **Generator obligation** – The imposition of a minimum technical standard on generators in the NEM, which could involve:

   (a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or

   (b) an option for generators to enter into an agreement with another provider.

2. **AEMO contract process** – The procurement of services via contracts with individual market participants through a competitive tender process undertaken by AEMO.

3. **TNSP provision** – The direct provision of services by TNSPs or the procurement of services by TNSPs under a modified Network Support and Control Ancillary Services (NSCAS) framework.

4. **Five-minute dispatch** – Prices are set for the services on a five-minute basis, which could involve:

   (a) the services incorporated in the dispatch process with a price paid to providers based on the value of the service in the five-minute dispatch interval; or

   (b) a separate dispatch process with offers submitted by providers of the services and a price determined for each five-minute interval.

To guide the development of these options, the Commission has set out a number of principles including:

1. **Certainty versus flexibility**: Arrangements must be flexible in a changing market environment and remain effective in achieving system security over the long term. This must be balanced against the need to provide investment certainty.

2. **Technology neutral**: Arrangements should be designed to take into account the full range of potential market and network solutions.

3. **Competition**: Competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning.

This chapter sets out the Commission's current thinking on the design of the different options, the suitability of each option for the two distinct services, the extent to which each option meets the assessment principles, and the ability of each option to also address the issues associated with system strength. While each of the options is discussed individually, an overall solution may involve the development of a combination of the options.

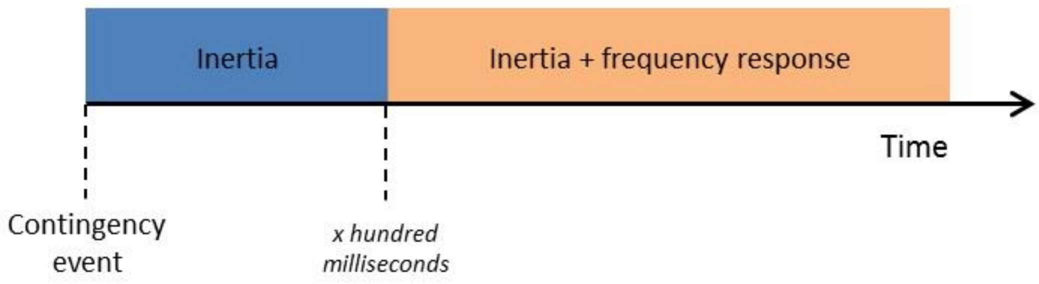
5.1 Inertia and fast frequency response are distinct services

Inertia and fast frequency response are distinct services which perform different roles in the management of system frequency. The Commission considers that both these services are likely to be needed to manage the future security of the power system.

The ability to slow a rapid change in frequency at the time of a contingency event is dependent on the level of inertia in the system. Fast frequency response technologies may respond rapidly to the sudden change in frequency. However, current FFR technologies exhibit a time delay in this response. This delay is comprised of the time taken to detect and measure the change in frequency and the subsequent time taken to activate the service and respond. While a number of technologies exhibit very rapid response times, the physical realities of accurately measuring frequency changes may limit the response capabilities of FFR technologies.

The time delay of FFR technologies implies that there is a level of inertia that must be online at any point in time to resist frequency changes at the time of the contingency event as well as over the first few hundred milliseconds following a contingency event. Beyond this initial time period, fast frequency response technologies have the potential to be used in combination with inertia to stabilise system frequency. This distinction between the roles of the two services is illustrated in figure 5.1.

Figure 5.1 Timeline for inertia and fast frequency response



Given the time delay of fast response services, the implication is that it would be necessary to design a mechanism which would provide for sufficient inertia to be online to limit high RoCoF at the time of, and immediately following, the occurrence of a contingency event.

The same mechanism, or a separate mechanism, could then be used to obtain fast frequency response services to stabilise frequency after the initial time period. Co-optimisation of the services would likely lead to lower overall cost arrangements. However, it is not yet clear whether this co-optimisation can occur on a real-time basis or over a longer time period.

As discussed in chapter 4, the level of inertia that is required to maintain the RoCoF to a given limit can be divided into a minimum system security component and an energy cost reduction component. In addition to obtaining additional inertia for the energy cost reduction component, the provision of FFR may be another alternative to constraining the system, thereby lowering the overall cost of energy provision.

5.2 Principles to guide the development of options

The Commission has set out the following principles to guide the development of options to obtain additional system security services.

1. **Certainty versus flexibility**: Arrangements must be flexible in a changing market environment and remain effective in achieving system security over the long term. This must be balanced against the need to provide investment certainty.

2. **Technology neutral**: Arrangements should be designed to take into account the full range of potential market and network solutions.

3. **Competition**: Competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning.

5.2.1 Certainty versus flexibility

The extent to which services are likely to be provided over the long term may be dependent on the level of certainty that can be provided in relation to investment. A secure power system demands the availability of system security services at all times. Regulatory frameworks must be designed to accommodate this requirement by providing certainty to prospective investors as well as existing providers. However, while greater investment certainty may help to ensure that the services are available when they are needed, this may come at the expense of the flexibility to continuously adjust the requirement under changing market conditions.

The NEM design promotes economic efficiency in dispatch through the determination of generator output on a five-minute basis in accordance with maximising the value of trade. Flexibility in adjusting to changing market conditions is achieved through the ability of generators to rebid their offered generation capacity between price bands. Investment certainty is underpinned by a separate secondary contract market which permits market participants to obtain a fixed price for the provision of energy up to four years ahead. The liquidity in the secondary contract market is facilitated by the presence of multiple potential trading counterparties and the settlement of energy payments limited to five regional prices.

Achieving a secure operating system in an economically efficient manner requires market frameworks to be designed to encourage investment in system security services and to maximise flexibility in the provision of those services to achieve an economically efficient outcome.

Further, regulatory or policy changes should not be implemented to address issues that arise at a specific point in time or in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances at different times and in different jurisdictions. They should be effective in maintaining system security where it is needed while not imposing undue market or compliance costs on other areas.

5.2.2 Technology neutral

Arrangements should be designed to take into account the full range of potential market and network solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly and, to the extent possible, a change in technology should not require a change in arrangements.

When considering how frameworks accommodate new technologies, it is the functions they perform that need to be the focus, not the technologies themselves. As set out in section 3.3, the relative immaturity and inherent delay in the operation time of fast frequency response technologies at present means that some level of system inertia is required to maintain a stable system frequency. However, fast frequency technologies may have an important future role in reverting frequency to normal operating levels following a contingency.

While inertia and fast frequency response may have separate but related roles to play in stabilising the system, there are a variety of technologies that are capable of providing each of these services. Inertia may be provided by synchronous generators and synchronous condensers. Wind, solar and batteries are all examples of technologies that have the capability to rapidly respond to deviations in system frequency.

5.2.3 Competition

Competition and market signals generally lead to better outcomes than prescriptive rules or centralised planning since they are more flexible to changing conditions and give businesses the ability to meet consumers' needs as efficiently as possible. Such outcomes should be less likely to change over time, creating regulatory certainty. Markets should be designed to maximise opportunities for the provision of services in order to send the right price signals and lower the overall cost of achieving a secure electricity system.

However, requiring solutions that address issues in specific network locations may limit the ability to maximise opportunities for service provision. System frequency is a global issue while system strength issues tend to be locationally specific. The range of service providers that are available to address system frequency may narrow if the same service providers are also required to address issues of system strength.

5.3 Overview of options

New mechanisms for the provision of additional system security services could be established for inertia and fast frequency response. These mechanisms are discussed below and include:

1. **Generator obligation** – The imposition of a minimum technical standard on each generator in the NEM, which could involve:

   (a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or

   (b) an option for generators to enter into an agreement with another provider.

2. **AEMO contract process** – The procurement of services via contracts with individual market participants through a competitive tender process undertaken by AEMO.

3. **TNSP provision** – The direct provision of services by TNSPs or the procurement of services by TNSPs under a modified Network Support and Control Ancillary Services (NSCAS) framework.

4. **Five-minute dispatch** – Prices are set for the services on a five-minute basis, which could involve:

   (a) the services incorporated in the dispatch process with a price paid to providers based on the value of the service in the five-minute dispatch interval; or

   (b) a separate dispatch process with offers submitted by providers of the services and a price determined for each five-minute interval.

As discussed above, maintaining the power system in a secure operating state requires that a minimum level of inertia is provided at all times. Each of the options set out below are discussed in the context of obtaining additional inertia to support system security. To the extent that there are any differences in the development of the option for fast frequency response services, these are subsequently identified.

5.4 Generator obligation

The generator obligation involves the imposition of a minimum technical standard on each generator in the NEM to provide a specified level of inertia.

This could involve:

(a) an obligation on generators to physically acquire or build the necessary equipment to meet the standard; or

(b) an option for generators to enter into an agreement with another generator or inertia provider for the required level of inertia.

There are four key elements that require consideration relating to the design of this option:

1. Specifying the nature of the obligation.

2. Determining the level, or minimum standard, that generators must satisfy.

3. For those generators that do not physically meet the obligation, the arrangements for entering into agreements with other providers of inertia.

4. The treatment of existing generators versus new-entrant generators.

5.4.1 Specifying the obligation

The establishment of a generator obligation would require the exact nature of the obligation to be specified and the level of the obligation determined.

There are two possible approaches to specifying the minimum standard that generators are required to satisfy:

1. **Generation online** - the minimum standard could be specified in terms of MW.seconds of inertia per MW of generation capacity online. For example, a 5 MW.second per MW minimum standard would mean that when a generator has 1000 MW of generation online, it would be required to provide at least 5000 MW.seconds of inertia. The inertia requirement would fall to 4000 MW.seconds if the generator's output reduced to 800 MW.

2. **Installed capacity** – the minimum standard could be specified in terms of MW.seconds of inertia per MW of installed generation capacity. For example, a 5 MW.second per MW minimum standard would mean that a generator with 1000 MW of installed generation capacity would be required to provide at least 5000 MW.seconds of inertia at all times.

Any obligation placed on generators to limit the RoCoF to a certain level would need to consider the RoCoF withstand capability of the generators that are providing the inertia. An obligation may have limited effect if it is designed to require generators to provide inertia in order to limit the RoCoF to a level that is higher than the RoCoF withstand capabilities of the generators.

Generation online

A minimum standard that varies in proportion to generation capacity online would mean that generators are not required to provide inertia to the system if they are offline or otherwise not dispatched. For synchronous generators, inertia is a by-product of the generation of electricity. An obligation to provide inertia at all times would require synchronous generators to remain at minimum generation output or otherwise enter into an agreement with another provider of inertia for the periods when they are offline.

As such, a minimum standard based on generation online is only likely to create a practical obligation for non-synchronous generators. Currently, the large proportion of non-synchronous generators are utility scale wind and solar farms. These generators tend to be intermittent in their production of electricity and have low operational capacity factors. An obligation to provide inertia in proportion to generation online may be preferable for these generators, although they would at least need to be able to source the capability to provide inertia in proportion to their total installed capacity for periods when they are operating at full output. This has the potential to result in an over-investment in inertia, which may be an inefficient outcome.

Installed capacity

An alternative to a minimum standard based on generation capacity online would be to apply the obligation in terms of installed generation capacity. This would require all generators to provide a minimum level of inertia at all times in proportion to their total installed capacity.

The relatively large level of inertia provided under this scenario would increase the likelihood that sufficient inertia is provided to maintain system security under different combinations of generator dispatch arrangements. However, such a large obligation at all times may prove too onerous on generators, particularly because, in most cases, the provision of inertia is a by-product of the provision of energy.

It may be possible to reduce the obligation on generators by lowering the level of the minimum standard. However, the sufficient provision of inertia at certain times may require AEMO to be able to dispatch the provision of inertia centrally. This may require AEMO to direct the operation of synchronous condensers or synchronous generators at certain times to maintain the security of the power system.

5.4.2 Determining the level of the obligation

Setting the level of the obligation, or minimum standard, will require consideration of the level of costs to impose on generators to reduce the probability of the failure of the power system and the costs on consumers and market participants that may arise as a consequence. This may be a role for the Reliability Panel and could be informed by modelling and analysis undertaken by AEMO.

The entity responsible for setting the level would consider both:

- **System security** – this would set a lower bound on the minimum standard, being the minimum level of inertia required to maintain secure operation of the system.
- **Market benefits** – any inertia that generators are required to provide above the amount needed to maintain system security would alleviate constraints in the system, thereby potentially providing market benefits.

In the case of the separation of South Australia, the system security component would be the minimum level required to maintain system security and would determine the level of the instantaneous RoCoF if the interconnector were to trip with zero flow. Additional inertia provided under the market benefits component would allow for increased flows on the interconnector.

An important question is whether the entity responsible for setting the level of the obligation should be charged with making decisions in relation to the optimal use of the interconnector. The decision to acquire additional inertia over and above the level required to maintain stability of the system would seem not to be a question of system security, and may therefore be at odds with the notion of a technical obligation.

Further, an obligation on generators is likely to have to be determined upfront with limited scope to vary the obligation over time. As such, there is a risk that a generator obligation may be under or over-specified, increasing the costs of maintaining system security over the long term.

5.4.3 Meeting the minimum standard

The generator obligation option envisages that generators that do not physically meet the minimum standard may use some combination of:

1. purchasing new equipment (eg synchronous condensers, flywheels) to increase the inertia that they have online while generating;

2. entering into an agreement with another generator with excess inertia above the minimum standard, or a third party provider; or

3. ceasing to generate when inertia is scarce.

The minimum standard would create demand from generators that are unable to provide sufficient inertia when they are generating.

While generators may be able to purchase new equipment to meet the minimum standard, this may prove to be a more expensive option than entering into an arrangement with another provider of inertia. A third party provider of inertia may be able to provide inertia at lower cost by gaining economies of scale and contracting for the provision of inertia with multiple counterparties.

Economic efficiency in the generator obligation option is likely to be improved by generators being able to enter into arrangements with one another, and with providers of inertia (eg synchronous condensers), to meet the minimum standard in a relatively efficient manner. However, consideration may need to be given to the following aspects of such an arrangement.

- The mismatch in generation profiles may present some challenges in finding suitable counterparties, ie wind farms are intermittent in the production of electricity while thermal generators tend to more closely follow demand. This would suggest that contracts for the provision of inertia would be most efficient if they pooled as many buyers and sellers of inertia as possible. This type of market may be more operationally efficient with the involvement of a central organiser.

- Coupling synchronous generation to non-synchronous generation through contracts may create some anomalies in central dispatch. At times of high wind output, such contracts may force on synchronous generation to support the wind, thereby ‘doubling on’ generation. In contrast, when a synchronous generator shuts down, it may force off non-synchronous generation, thereby 'doubling off' generation.

- If AEMO had central control of the inertia, it is not clear how dispatch would be coordinated across the different generators and inertia providers. The contractual arrangements between participants may need to be undertaken as part of a transparent negotiated process such that AEMO would be able to determine a basis upon which to prioritise the dispatch of generators to achieve an economically efficient outcome.
- The ability of a generator to enter into a contract with another generator in a different region would be limited. For example, in South Australia a minimum level of inertia is required to maintain system security in the islanded region following separation. Entering into a contract with a generator outside of South Australia would not provide the required inertia in the islanded region should failure of the Heywood Interconnector cause separation from Victoria. However, confining the trading of inertia to within regions may limit competition. This reasoning could also potentially restrict the ability of generators within the same region to contract for the provision of inertia if there was a risk of intra-regional separation.

5.4.4 Applying the obligation to different generators

Consideration would also need to be given to whether there would be restrictions in applying the obligation to certain types of generators. The obligation could be restricted to new entrant generators or extended to apply to all existing generators. Equally, the obligation could be restricted to scheduled generators or extended to apply to non-scheduled generators as well.

Treatment of existing versus new entrant generators

To address the immediate challenges to system security in the NEM (ie those in South Australia), the standard would need to apply to at least some existing generators. Restricting the obligation to new entrant generators (and assuming no other option was employed to provide inertia) would likely require the system to be heavily constrained in order to manage RoCoF.

Imposing the obligation on existing generators may give rise to situations where generators find it difficult or expensive to meet the obligations, which may present a risk of stranded assets. In some cases it may be difficult to impose the obligation on certain generators and there may be issues in determining which specific existing generators should be required to meet the obligation.

In addition, placing an obligation on existing generators to amend their performance standards may create inconsistencies with their existing connection agreements with NSPs. Connection agreements include the agreed performance standards with respect to each of the relevant technical requirements, which are based on either the automatic access standard or the negotiated access standard for that technical requirement as set out in the NER.

Once a connection agreement is in place, it cannot be varied except as agreed by both parties. If this option were to be pursued, the AEMC may need to investigate other means of imposing the obligation on existing generators through other relevant areas of the NER or National Electricity Law (NEL).

Treatment of non-scheduled generators

An obligation applied only to scheduled generators may not result in the provision of sufficient inertia to maintain system security if a large proportion of demand is supplied through non-scheduled generation sources. Regions such as South Australia are likely to experience increasing penetration of rooftop solar and it is possible that, at some point in the future, demand may reach levels where it can be supplied through interconnector imports alone (or even exporting). A technical obligation that is restricted to scheduled generators only may not provide sufficient inertia to maintain system security at these times.

Central control of inertia services by AEMO may still not be of assistance in these instances as they would be limited in their ability to constrain off the generation being supplied from rooftop solar.

5.4.5 A generator obligation for fast frequency response

It may be possible to impose an obligation on generators to provide a specified level of FFR services. The ability of FFR to respond rapidly to a sudden frequency change caused by a contingency event may, to a limited extent, reduce the amount of inertia that is needed.

As with inertia, the technical specifications of the service would need to be determined. Similar to existing FCAS technologies, FFR involves a power injection to stabilise movements in frequency following a contingency. This power injection can have a range of characteristics which would need to be specified when imposing the requirement as an obligation on generators. These characteristics include the response and activation time, the duration of the response, and the profile of the power injection.

As discussed in section 3.3, the inherent delay in response times of FFR services, as well as the relative immaturity of current FFR technologies, suggests that a minimum level of inertia is required in the current market environment at all times in order to maintain system security.

However, imposing a technical obligation on generators that focuses solely on the provision of inertia may result in an abundance of inertia which may act as a barrier to future innovation in FFR technologies, or may direct developments in FFR towards a particular outcome, eg as a replacement for inertia. Conversely, some investments in inertia may end up as stranded assets through subsequent advancements in FFR technologies.

If a technical specification could be developed and applied, this may have some benefit in facilitating the development and provision of FFR services. This may provide a foundation for the future creation of a competitive market for the provision of the service.

5.4.6 Impact on system strength

The provision of inertia through a generator obligation is likely to increase the system strength in parts of the power system, but the extent of the increase would depend on how the technical obligation is met by each of the generators. This is because a technical obligation to provide a quantity of inertia would generally increase the quantity of synchronous generating units and synchronous condensers that are operating at any given time.

When a generator wishes to connect a generating unit with no inertia in a location in the system that also has low system strength, then it is likely to install a synchronous condenser. This would both meet its technical obligation to provide inertia and increase the system strength at that location, which would improve its ability to meet its performance standards.

However, if a generator meets its technical obligation by contracting with another generator then the impact on system strength will depend on the location of the contracted synchronous generating unit or synchronous condenser.

These arguments equally apply to the provision of FFR services, although the ability of FFR to contribute to system strength is less clearly defined than inertia.

5.5 AEMO contract process

An AEMO contract process would involve the procurement of the required amount of inertia via a competitive tender process or a bilateral negotiated process. An example of this type of approach is the process currently used to procure System Restart Ancillary Services (SRAS).

There are three key design elements for this option:

1. Determining the required level of the inertia to procure.

2. The form or characteristics of the contract.

3. The arrangements for recovering the costs of the contract.

5.5.1 Determining the required level of inertia

The costs of paying for the provision of inertia through contracts with providers would need to be assessed against the cost of potential alternative measures, such as constraining the system, as well as the cost of possible consequences arising from a failure to maintain system security.

Similar to the generator obligation, the required level of inertia can be divided into two components which would service separate functions.

- **System security** – a minimum amount of inertia required at all times to maintain the security of the system.
- **Energy cost reduction** – beyond the amount required to perform the system security function, additional inertia procured under contract would allow the alleviation of system constraints which may reduce energy costs.

The contract process could be used to procure inertia for both purposes. AEMO would procure the minimum level of inertia needed for system security via contracts with providers. AEMO would then make a decision about how much inertia should be procured to alleviate constraints to minimise the overall cost of dispatched energy. This decision would involve a trade-off between the cost of procuring more inertia and the benefits that this provides to the energy market.

To determine the level of inertia to contract, AEMO would be informed by market modelling to estimate the optimal amount of inertia to procure on the basis of expectations of future energy demand.

AEMO's assessment of the required level of inertia for both the system security component and the energy cost reduction component would be informed by the limit on RoCoF. The RoCoF would determine the minimum amount of inertia required for the system security component and would provide an exchange rate between the procurement of inertia and constraining the system to limit the size of contingencies, ie the RoCoF limit would determine the extent to which system constraints could be alleviated for an incremental increase in inertia.

5.5.2 Determining the form of the contract

Critical to AEMO's ability to procure the required level of inertia from providers would be the form and conditions of the contract.

The following are likely to be some of the key characteristics of the contract:

- Term of the contract, eg annual.
- Timeframe for procurement, eg three years in advance of the requirement.
- Payment structure, eg a fixed amount on the basis of availability and a variable change based on the level of inertia actually provided.
- Penalties, eg units that fail to provide inertia when required may forfeit their availability payments.
- A reserve margin to increase the likelihood that the target quantity of inertia can be provided, assuming some level of outages.

AEMO might develop guidelines to specify the conditions of the contract and there would likely be some level of bilateral negotiation, similar to NSCAS contracts which are negotiated between the NSP and the service provider.

The conditions of the contract would be likely critical in encouraging existing providers to provide inertia when it is needed and to provide certainty to prospective providers to encourage investment. While certainty in the term and payment structure of the contract will provide greater incentives for investment, this will likely need to be balanced against the need to maintain flexibility in the payment structure to avoid an over-procurement of inertia and to be able to adjust the level of inertia provided at any point in time to account for variable system conditions.

It is possible that a fixed payment for availability would provide the necessary level of certainty to investors and create an incentive for the inertia to be available and provided when required. The fixed payment seems more appropriate to encourage provision of the minimum requirement to satisfy the system security component of inertia. However, it would seem potentially inefficient to provide availability payments for the energy cost reduction component of inertia. For example, in South Australia, limiting flows on the interconnector may be a more optimal course of action at certain times than paying for the provision of higher levels of inertia.

Given that for synchronous generators the provision of inertia is a by-product of energy production, consideration may need to be given as to how generators would be incentivised to provide inertia under contract if the price paid in the energy market is below their offer price. Conversely, a generator providing inertia may not need to be paid for that inertia if the price in the energy market is above their offer price and they would have generated anyway. It is not clear how a model based on contract procurement of inertia would interact with the energy market.

5.5.3 Cost recovery arrangements

Similar to the manner in which the level of required inertia is determined, the cost recovery arrangements could also be divided into the costs attributable to the system security component of inertia and costs attributable to the energy cost reduction component of inertia.

Inertia provided as a minimum to maintain system security benefits all market participants. Reflecting the view put forward in AGL's rule change request, costs associated with this level of inertia could be recovered from both generators and loads in proportion to energy production or consumption, with a 50/50 split between generators and loads.[33]

Additional inertia provided above the level required to maintain system security lowers the overall energy market costs to the benefit of customers. It would seem appropriate that these costs would be recovered from customers in proportion to their energy consumption.

33 AGL, *Inertia ancillary service market - rule change request*, 24 June 2016, p. 4.

Over the course of a year, there will be periods when inertia is relatively expensive or cheap to provide. As such, it may be preferable if possible that cost recovery under the contracts recognises this variation in the value of inertia, particularly for the energy cost reduction component.

A further consideration is how costs should be recovered from customers in one region that benefit from the provision of inertia in another region.

5.5.4 AEMO contract process for fast frequency response

The current power system design depends on a minimum level of system inertia to be available at the time of a contingency event in order to limit the RoCoF and remain within the bounds of the FOS. However, there is likely to be a significant role for FFR to play in responding to frequency changes within timeframes beyond a few hundred milliseconds and assisting in the stabilisation of system frequency.

Contracts used to procure FFR would involve an economic decision to be made around the level of FFR to procure given the alternatives of procuring additional inertia or further constraining the interconnector.

Unlike inertia, FFR is not generally a direct by-product of energy production. As such, coordination of payments under contract with payments in the energy market is likely to be more straightforward for the provision of FFR. FFR is typically provided independently of energy and so a provider could be paid separately for the provision of the two different services.

Contracts would also have the benefit of underpinning investor certainty. This may be particularly useful given the relative immaturity of the majority of FFR technologies and the likely perception of these technologies as a high risk investment. The level of certainty provided to investors would be influenced by the terms of the contract, such as duration, timeframe for procurement, and payment structure.

5.5.5 Impact on system strength

The provision of inertia through a contracting process undertaken by AEMO is likely to increase the system strength through the increased provision and operation of synchronous generating units and synchronous condensers.

While a general increase in inertia is likely to cause a general increase in system strength, a contract tender process may not be suitable to addressing system strength issues in specific areas of the network. It may be possible for NSPs to identify and communicate to AEMO areas of the network where there is low system strength. AEMO may then be able to use this information in determining potential providers of inertia. However, as discussed in chapter 4, solutions that address system strength issues in specific network locations may limit the ability to maximise opportunities for the provision of inertia. The range of inertia providers that are available to address system frequency may narrow if the same inertia providers are also required to address issues of system strength.

These arguments equally apply to the provision of FFR services, although the ability of FFR to contribute to system strength is less clearly defined than inertia.

5.6 TNSP provision

TNSP provision of inertia would involve either the direct provision of services by the TNSP (eg installing synchronous condensers) or the procurement of the required amount of inertia via contracts with inertia providers under the Network Support and Control Ancillary Services (NSCAS) framework, or similar, as set out in the NER. Contracts would be formed under a process of negotiation between the TNSP and the inertia provider.

There are three key design elements for this option:

1. Determining the required level of the inertia to procure.

2. The form or characteristics of the contract.

3. The arrangements for recovering the costs of the contract.

5.6.1 Determining the required level of inertia

The required level of inertia can be divided into two components which would service separate functions.

- **System security** – a minimum amount of inertia required at all times to maintain the security of the system.

- **Energy cost reduction** – beyond the amount required to perform the system security function, additional inertia procured under contract or directly would allow the alleviation of system constraints which may reduce energy costs.

The extent to which the NSCAS framework could be used to procure inertia for both purposes is not clear. The NSCAS framework may be more appropriate for the procurement of the minimum amount of inertia. For the energy cost reduction component, the costs of paying for the provision of inertia through contracts with providers would need to be assessed against the cost of potential alternative measures, such as constraining the system. This would seem to be a task more appropriately undertaken by AEMO. The decision would involve a trade-off between the cost of procuring more inertia and the benefits of alleviating constraints to minimise the overall cost of dispatched energy.

Under the NSCAS framework, NSPs may procure services if they identify a need. AEMO may also identify “gaps” in the volume of NSCAS procured by NSPs through its National Transmission Network Development Plan (NTNDP). This is currently the case for system reactive support in some locations.

It is not clear that the NER would currently allow inertia to be purchased as NSCAS under the existing definition. NSCAS includes network loading, voltage control, and transient and oscillatory stability. It is possible that some inertia could be provided as a by-product of the provision of the above services. However, a separate inertia specification could potentially be included in the NER.

Further, NSCAS is currently not able to be procured to manage the occurrence of non-credible contingencies. However, a separate category of protected events, as discussed in section 4.2, may provide an avenue for the identification of a "gap" and the procurement of services for events such as the double-circuit loss of the Heywood Interconnector.

NSCAS may provide a means for additional system security requirements to be included in the procurement process, such as system strength. However, the localised nature of system strength issues may mean that the process for NSCAS procurement may not be as competitive as a general tender process conducted by AEMO.

5.6.2 The form of the contract

Similar to the AEMO contract process, the TNSP's ability to procure the required level of inertia from providers would likely depend on the form and conditions of the contract.

Certainty in relation to the term and payment structure of the contract would potentially provide greater incentives for investment. However, this will likely need to be balanced against the need to maintain flexibility in the payment structure to avoid an over-procurement of inertia and possibly to be able to adjust the level of inertia provided at any point in time to account for variable system conditions.

There are currently four types of NSCAS payments:

1. Availability payments – made for every trading interval that the service is available.

2. Enabling payments (for some subsets of Reactive Power only) – made only when the service is specifically enabled.

3. Usage payments (for some subsets of load shed only) – made when the service is successfully delivered in response to an instruction from AEMO.

4. Testing payments – made when a test is successfully conducted.

It is possible that a fixed payment for availability would provide the necessary level of certainty to investors and create an incentive for the inertia to be available and provided when required. The fixed payment seems more appropriate to encourage provision of the minimum requirement to satisfy the system security component of inertia. Usage payments would seem to be more appropriate for the energy cost reduction component of inertia where the costs of paying for the inertia can be compared against the alternative cost of constraining the system.

5.6.3 Cost recovery arrangements

NSCAS costs are recovered from market customers on a regional basis. The recovery of costs is divided up between regions according to the regional benefit framework. The intention is for costs to be recovered from the region that correspondingly benefits from NSCAS services.

Within each region, costs are covered from market customers in proportion to the energy they consume. This is done at the five-minute level.

Under the regional benefit framework, the cost of NSCAS dispatched to provide power system security management is recovered evenly from benefiting regions. Where NSCAS is dispatched to provide an increase in the interconnector flow between two regions, the costs are recovered only from the region receiving power.

Application of this framework to the provision of inertia may suggest that the costs of the system security component of inertia could be recovered equally from benefitting regions. The costs of inertia for the energy cost reduction component could depend on the direction of flows on the interconnector. In the case of inertia procured through NSCAS in South Australia, the costs would be recovered from South Australian customers at times when importing from Victoria, and from Victorian customers when exporting to Victoria.

5.6.4 TNSP provision of fast frequency response

The current power system design depends on a minimum level of system inertia to be available at the time of a contingency event in order to limit the RoCoF and remain within the bounds of the FOS. As such, NSCAS contracts used to procure FFR would only be able to apply to act as a substitute for the energy cost reduction component of inertia. This would involve an economic decision to be made around the level of FFR to procure given the alternatives of procuring additional inertia or further constraining the system. This would not appear to be an appropriate role to be undertaken by a TNSP.

Similar to the AEMO contract process, NSCAS contracts would have the benefit of underpinning investor certainty. This may be particularly useful given the relative immaturity of the majority of FFR technologies and the likely perception of these technologies as a high risk investment.

5.6.5 Impact on system strength

The provision of inertia through a NSCAS contracting process is likely to increase the system strength through the increased provision and operation of synchronous generating units and synchronous condensers. While a general increase in inertia is likely to cause a general increase in system strength, a key benefit of the NSCAS process is that localised network issues, such as system strength, may be evaluated and incorporated in the decision of the location of the inertia provider.

5.7 Five-minute dispatch

In the five-minute dispatch option, prices would be set for the services on a five-minute basis, which could involve:

(a) incorporation of the services in the dispatch process with a price paid to providers based on the value of the service in the five-minute dispatch interval; or

(b) a separate dispatch process with offers submitted by providers of the services and a price determined for each five-minute interval.

There are three key design elements for this option:

1. Incorporating the service into the five-minute dispatch process.

2. Creating the mechanism to price the service.

3. Establishing arrangements for recovering the costs of the service.

5.7.1 Incorporating inertia into five-minute dispatch

Currently, the majority of inertia is provided by synchronous generators. While other sources, such as synchronous condensers, may also contribute at present, the provision of inertia is largely a by-product of the provision of energy. It follows that there may be benefits from incorporating the sourcing of inertia with the energy market dispatch process.

Inertia is provided in blocks

For any five-minute dispatch interval, the level of inertia in the system is currently dependent on the combination of synchronous generators that are online at the time. Generators provide all of their inertia when they are online or no inertia when they are offline, regardless of energy output. Therefore, any increase in the level of inertia would require the start up of an additional generating unit. This is different to energy where an incremental increase in the demand for energy can generally be accommodated by an incremental increase in the output of the generating units that are already online.

The provision of inertia through a five-minute dispatch model may require generators to be notified well in advance of the relevant dispatch interval, such as through a day-ahead dispatch model.

5.7.2 Creating a mechanism to price inertia

For every dispatch interval in the energy market, AEMO solves the dispatch program using the National Electricity Market Dispatch Engine (NEMDE) to bring supply and demand into balance. For a given dispatch interval, the process yields a solution, which comprises a set of instructions to operate the power system at least cost. These instructions include:

- the output level for every generating unit;
- the level of all scheduled loads; and
- the flows on interconnectors between regions.

An output, or by-product, of solving the dispatch program is the dispatch price for each region. The dispatch price is equal to the value of the next unit of electricity available to be supplied to that region for that dispatch interval. It is the marginal cost of the constraint that supply must equal demand.

Prices can be derived from other constraints in the dispatch process as well. The 'shadow price' is equal to the marginal cost of a constraint, ie how much money could have been saved if the constraint were relaxed by a very small amount.

This principle can be applied to determine a price for inertia. In the case of South Australia, the critical constraint related to inertia is given by:

$$\frac{25\ [Hz] \times Heywood\ Flow\ [MW]}{RoCoF\ [Hz\ per\ second]} \leq Inertia\ [MW.seconds]$$

Assuming that a hypothetical 1 MW.s (or simply a very small) provider of inertia is included in the system, taking the shadow price of this constraint would yield a price for inertia equal to its marginal value.

In other words, given a RoCoF limit, the incremental value of inertia could be determined by the value of an incremental increase in the flow on the Heywood Interconnector, ie the value of inertia relates to the difference in the regional reference prices between South Australia and Victoria.

Note the role of the RoCoF limit in this equation. All else being equal, a higher RoCoF limit increases the amount of power that can flow across the Heywood Interconnector.

When there is insufficient inertia available to maintain system security, the price would be set at a market price cap. A market price cap (and potentially a cumulative price threshold) could be set for inertia, to promote market stability (ie through limiting price exposure and volatility above the level required to incentivise investment).

5.7.3 Cost recovery arrangements

This option would create a price for inertia on a five-minute basis, which would be paid to providers of inertia. Multiplying the amount of inertia purchased (ie the optimal amount as determined through dispatch) by the price of inertia would yield the total cost of the services.

Similar to the manner in which the level of required inertia is determined, the cost recovery arrangements could also be structured to separately recover the costs attributable to the system security component of inertia and costs attributable to the energy cost reduction component of inertia.

Inertia provided as a minimum to maintain system security benefits all market participants. These costs could be recovered from both generators and loads in proportion to energy production or consumption.

Additional inertia provided above the level required to maintain system security lowers the overall energy market costs to the benefit of customers. It would seem appropriate that these costs would be recovered from customers in proportion to their energy consumption.

Five-minute dispatch determines the optimal amount of inertia to purchase to minimise total dispatch costs.

- If the dispatch engine purchases inertia to alleviate the constraint on the interconnector, it does so because that is cheaper than the cost of running the dispatch with the interconnector constrained.

- If the dispatch engine does not purchase inertia, and instead constrains the interconnector, it does so because the additional energy costs do not outweigh the costs of the inertia.

A further consideration is how costs should be recovered from customers in one region that benefit from the provision of inertia in another region.

An example of where services in one region provides benefits to customers in other regions is the acquisition of additional inertia in South Australia to support the increased export of energy into Victoria, and potentially New South Wales, Queensland and Tasmania.

One option would be to adjust payments from market participants depending on the direction of flow on the interconnector. For example, South Australian consumers are likely to benefit from imports into South Australia via the Heywood Interconnector and could therefore be required to cover the costs of obtaining inertia within South Australia to resist high RoCoF should the interconnector trip in these circumstances. Conversely, South Australian generators could be required to cover the costs of obtaining inertia at times when South Australia is exporting to Victoria.

This option would not charge generators or consumers in Victoria for the benefit to them of exports and imports from South Australia which may arise from inertia obtained from providers in South Australia.

5.7.4 Five-minute dispatch of fast frequency response

The current market environment would depend on a minimum level of system inertia to be available at the time of the contingency event. However, there may be a significant role for FFR in responding to frequency changes within timeframes beyond a few hundred milliseconds and assisting in the stabilisation of frequency following the contingency.

Obtaining FFR through the five-minute dispatch would involve a co-optimisation between the level of FFR, the level of inertia, and constraining the interconnector.

The price for FFR could be obtained in a similar fashion to inertia, taking the shadow price of the constraint:

$$Heywood\ Flow\ [MW] - \frac{Inertia\ [MW.seconds] \times RoCoF\ [Hz\ per\ second]}{25\ [Hz]} \leq\ FFR\ [MW]$$

This calculation would only apply in timeframes beyond a few hundred milliseconds when FFR technologies can be utilised.

An alternative to pricing FFR in NEMDE would be to have a separate dispatch process for FFR which is similar to the existing arrangements for contingency FCAS.

Unlike inertia, FFR is not a by-product of energy production. Therefore, it is possible that FFR could be priced similar to existing FCAS with providers of the services placing offers in a separate dispatch process. Similar to existing FCAS arrangements, there would be separate raise and lower services which would be co-optimised with the energy market.

The creation of a separate dispatch process for FFR would reflect the fact that FFR is not a perfect substitute for inertia. FFR could be obtained through a separate dispatch process to control frequency changes over a pre-determined timeframe, similar to existing contingency FCAS arrangements. A separate dispatch process may also allow for a greater range of service providers to participate.

There is a risk that the creation of a separate dispatch process for the provision of FFR services may be premature given the fledgling state of the range of available technologies. The benefits of a five-minute dispatch model may reside more in the efficient dispatch and operation of the technologies rather than the ability to provide the necessary certainty that investors may seek in the provision of a relatively immature service.

5.7.5 Impact on system strength

The provision of inertia through a five-minute dispatch process is also likely to increase the system strength through the increased provision and operation of synchronous generating units and synchronous condensers.

The disadvantage in terms of the system strength of a five-minute process for inertia is that the provision of inertia would be separated from the management of system strength. This separation would make it more difficult for the provision of inertia to be coordinated with the management of system strength.

6 Lodging a submission

The Commission is inviting written submissions on this Interim Report. Submissions are to be lodged online or by mail by 9 February 2017 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change requests. The Commission publishes all submissions on its website, subject to a claim of confidentiality.

All enquiries on this project should be addressed to Sebastien Henry on (02) 8296 7800.

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the relevant project reference code as follows:

EPR0053 – System Security Market Frameworks Review

ERC0208 – Inertia Ancillary Services Market

ERC0214 – Managing Power System Frequency

ERC0211 – Managing Power System Fault Levels

Comments made in submissions that do not reference a particular project code will be treated as comments that apply to all and any of the rule change requests and the Review.

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

6.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Or by Fax to (02) 8296 7899

The envelope must be clearly marked with the relevant project reference code, as above.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
FCAS	Frequency Control Ancillary Services
FFR	fast frequency response
FOS	Frequency Operating Standards
FPSS	Future Power System Security
NEL	National Electricity Law
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NEO	National Electricity Objective
NER or rules	National Electricity Rules
NSCAS	Network Support and Control Ancillary Service
NTNDP	National Transmission Network Development Plan
RoCoF	rate of change of frequency
SRAS	System Restart Ancillary Services
UFLS	under-frequency load shedding
USE	unserved energy