RULE CHANGE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

National Electricity Amendment (Inertia ancillary service market) Rule 2017

Rule Proponent

AGL

7 November 2017

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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 Australian Energy Market Commission (AEMC or Commission) has determined not to make a draft rule relating to the introduction of a market mechanism for power system inertia at this time.

The draft rule determination has been made with respect to a rule change request received from AGL, which proposes the establishment of an inertia ancillary services market to address the declining supply of inertia in the National Electricity Market (NEM).

On 19 September 2017, the AEMC made a final rule determination with respect to the rule change request received from the South Australian Government on *Managing the rate of change of power system frequency.* The final rule places an obligation on TNSPs to make available the minimum level of inertia required to maintain secure operation of the power system. As such it provides confidence that system security can be maintained in all regions of the NEM, while minimising the costs to consumers. The final rule commences on 1 July 2018 with TNSPs required to make the minimum level of inertia available by 1 July 2019.

The Commission supports the development of competitive markets for the provision of system services for achieving the most efficient outcomes for consumers. However, given the current power system operating conditions, the need to understand practical outcomes from new regulatory frameworks recently introduced, and assess outcomes from various programs of work on foot by the Commission and the Australian Energy Market Operator (AEMO), the Commission is not satisfied that the introduction of a market mechanism for additional inertia for market benefit will meet the national electricity objective (NEO) at this time.

The Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the recently initiated *Frequency control frameworks review*. Recommendations arising from this review will be provided in mid-2018.

Reasons for not making a draft rule

On 5 September 2017, the AEMC published a consultation paper relating to AGL's rule change request, which set out a straw man design of a market mechanism for the provision of power system inertia.

Substantial feedback from stakeholders was received in response to the consultation paper. While stakeholders are largely in support of the development of markets to value system services, many are not convinced of a clear or compelling need for the development of a market mechanism for inertia at this time. Many stakeholders have suggested delaying the introduction of a market for inertia until after the AEMC's *Frequency control frameworks review* is completed in mid-2018.

Four principal factors were raised by stakeholders in favour of not implementing a market mechanism for additional inertia for market benefit at this time:

1. The minimum levels of inertia required to maintain the system in a secure operating state has been addressed through a final rule on the South Australian Government's rule change request. There is now less urgency associated with introducing a complementary mechanism to facilitate the provision of additional inertia for market benefit. While this mechanism would likely contribute to the national electricity objective (NEO), careful design is necessary in order to make sure that the potential economic benefits are realised in an efficient manner.

2. The minimum levels of inertia required to maintain the system in a secure operating state will be determined by AEMO over the next eight months. The level of the minimum inertia requirement will allow the extent to which there is any residual market benefit from additional inertia to be identified.

3. The application of constraints by AEMO to manage low system strength issues in South Australia has had a consequential impact on the alleviation of the inter-regional rate of change of frequency (RoCoF) constraint on the Heywood Interconnector, suggesting limited market benefits could be obtained through the provision of additional inertia at this time.

4. Further consideration needs to be given as to how inertia can be accurately valued with the application of constraints to manage other system security requirements, such as system strength and system stability, and with the provision of alternative frequency control services, such as fast frequency response. AEMO is working to further understand the limits of power system operation with low levels of synchronous capability and is considering how system security constraints can be developed to address these issues in a holistic manner.

Submissions on this draft rule determination are due by **19 December 2017.**

Background to the rule change request

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 conventional electricity generators, operating 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.

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.

AGL's rule change request suggests that the changing mix of generation capacity in the NEM has led to the supply of inertia decreasing, limiting the ability of the system to cope with rapid changes in frequency due to significant changes in either supply or load.

On that basis, the rule change request proposes the introduction of an inertia ancillary services market as an appropriate response to the declining supply of inertia.

On 27 June 2017, the AEMC published its final report on the *System security market frameworks review*. The report made a number of recommendations, both for immediate measures to address priority issues and a further program of work to develop robust market frameworks for the longer term.

Two of the recommendations contained in the final report relate to the provision of power system inertia:

1. Place an obligation on transmission network service providers (TNSPs) to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.

2. Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on TNSPs.

Recommendations arising from the *Independent review into the future security of the NEM* (Finkel Panel) are consistent with the first of these recommendations but take a more reserved approach to the second recommendation, suggesting that a future move towards a market-based mechanism should only occur if there is a demonstrated benefit.

The AEMC made a final rule determination with respect to the first recommendation by placing an obligation on TNSPs to make available the minimum level of inertia required to maintain secure operation of the power system by 1 July 2019. The final rule also allows TNSPs to procure other services such as fast frequency response to reduce the minimum level of inertia required, with approval from AEMO.

The minimum level of inertia required to maintain secure operation of the power system can be distinguished from additional levels of inertia that may increase economic benefits by allowing for greater power transfers on the network, such as greater energy flows on interconnectors.

The final rule does not provide a mechanism to realise the market benefits that could be obtained through the provision of additional inertia above the minimum required level.

However, the Commission considers that a market mechanism will complement and build on the certainty created through the TNSP obligation by providing the ability to continuously adjust the level of service provision in real time to maximise efficiency.

The Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review.*

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1 AGL's rule change request

1.1 The rule change request

On 24 June 2016, AGL submitted a rule change request to the AEMC to make a rule regarding the introduction of an *Inertia ancillary services market* for the provision of power system inertia in the NEM.

AGL proposes that such a services market should provide a means of placing an efficient value on inertia in light of the "ongoing shift towards renewable energy in the NEM, changes in consumer preferences and the corresponding reduction in the level of inertia as synchronous generation capacity in the NEM is either mothballed or retired".[1]

The rule change request proposes the introduction of an inertia ancillary services market and that AEMO should be responsible for the procurement of inertia services on a competitive basis.

The Commission's draft rule determination is to not make a rule with respect to AGL's rule change request. The draft determination sets out the Commission's assessment of the need for a market mechanism and the rationale for its decision. It also outlines an approach to the development of a market mechanism for inertia to meet a potential future requirement.

1.1.1 The AEMC System Security Work Program

The AEMC initiated the *System security market frameworks review* on 14 July 2016 to consider changes to wholesale energy market frameworks to address the security of the power system with the shift to non-synchronous forms of generation in the NEM.

On 27 June 2017, the AEMC published the final report on the review. The report made a number of recommendations, both for immediate measures to address priority issues and a further program of work to develop robust market frameworks for the longer term.

Two of the recommendations contained in the report relate to the provision of power system inertia:

1. Place an obligation on TNSPs to provide minimum required levels of inertia, or alternative equivalent services, to allow the power system to be maintained in a secure operating state.

2. Introduce a market-based mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on TNSPs.

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1 AGL, *Inertia Ancillary Service Market,* Rule change request, 24 June 2016, p. 1.

Recommendations arising from the *Independent review into the future security of the NEM* are consistent with the first of these recommendations however take a more reserved approach to the second recommendation, suggesting that a future move towards a market-based mechanism should only occur if there is a demonstrated benefit.[2]

On 19 September 2017, the AEMC made a final rule determination with respect to the rule change request received from the South Australian Government on *Managing the rate of change of power system frequency*.[3]

The final rule addresses the first recommendation by placing an obligation on TNSPs to make available the minimum level of inertia required to maintain secure operation of the power system. The final rule does not provide a mechanism to realise the market benefits that could be obtained through the provision of additional inertia above the minimum required level.

With respect to the second recommendation, the Commission has also been assessing AGL's rule change request proposing the establishment of an inertia ancillary services market.

To progress further recommendations made in the *System security market frameworks review,* on 7 July 2017 the AEMC initiated a review into market frameworks necessary to support better frequency control: the *Frequency control frameworks review*. This review will continue to be coordinated with the ongoing technical work being completed by AEMO on frequency control issues under the terms of our collaboration agreement.

1.1.2 Current arrangements

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 synchronous 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.

2 Dr Alan Finkel, Independent review into the future security of the NEM, June 2017, p. 21.

3 AEMC, *Managing the rate of change of power system frequency - final determination*, 19 September 2017.

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. For example a rapid change may not allow enough time for existing emergency frequency control schemes to operate effectively.

The RoCoF is proportional to the size of the sudden change in supply or demand as a result of the contingency event and inversely proportional to the level of system inertia at the time that the contingency occurs.[4] The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change.

AEMO maintains the secure operation of the system by continuously monitoring the system frequency through the automatic generation control (AGC) system every 2-4 seconds and incrementally adjusts dispatch of generation to balance supply and 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.

Large deviations from the normal frequency level or high rates of change of frequency can also cause the disconnection of generation or load, and have the potential to lead to cascading failures.

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, or power station output, 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).

FCAS is concerned with the timely injection of active power to stop a change in frequency. FCAS has the ability to inject sufficient active power over a timeframe that maintains the technical performance of the power system, in this case the frequency operating standards (FOS). This differs to the role of inertia; inertia does not act to stop the frequency change or revert frequency back to normal operating levels.

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4 Contingency events may be classified as either credible or non-credible. A credible contingency is an event which AEMO considers to be reasonably possible. Generally, such events would involve the loss of one generating unit or network element. A non-credible contingency is any other contingency, a sequence of credible contingencies within a five-minute period, or a further separation event in an island.

In the NEM, FCAS is sourced from markets operating in parallel to the wholesale energy market, with the energy and FCAS markets being optimised simultaneously so that total costs are minimised.

1.2 Rationale for the rule change request

Newer types of electricity generators connected to the national electricity system, such as wind and rooftop solar, are not synchronous machines, have low or no physical inertia, and are, therefore, currently limited in their ability to dampen rapid changes in system 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 providing these rapid response services to manage the future security of the power system.[5]

AGL's rule change request suggests that the changing mix of generation capacity in the NEM has led to the supply of inertia decreasing, limiting the ability of the system to cope with rapid changes in frequency due to significant changes in either supply or load.[6]

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 connected. 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 that has the ability to provide inertia in that region at the time of the interconnector outage, the frequency could be subject to very rapid changes. This makes it harder to arrest the frequency change and restore the frequency to normal operating levels. As the generation mix changes in a similar way across the NEM these risks may become more widespread.

1.3 Solution proposed in the rule change request

AGL suggests that the introduction of an inertia ancillary services market is an appropriate response to the declining supply of inertia. Specifically, AGL proposes that the inertia services would be procured on a competitive basis by AEMO.[7] Under the competitive procurement arrangements, AEMO would:

- administer the market and determine the quantity of capacity to be contracted

5 While these services are currently not actively employed in the NEM, AEMO has been undertaking investigations into their potential use in the management of power system frequency and intends to report on its findings as part of its Future Power System Security (FPSS) work program.

6 AGL, *Inertia Ancillary Service Market,* Rule change request, 24 June 2016, p. 3

7 AGL, *Inertia Ancillary Service Market,* Rule change request, 24 June 2016, p. 4.

- determine the timeframe for the capacity to be procured
- be the responsible entity to conduct the tender/auction process
- set any relevant terms and conditions and any other relevant requirements associated with procurement
- complete any other relevant functions as necessary to ensure that the service contracted is reliable, contracted efficiently and competitively.

AGL suggests that contracting for the provision of inertia services would need to be region specific in order to allow for the islanded operation of NEM regions.

AGL has proposed that cost recovery of the inertia services could be based on a 50/50 split between customers and generators.[8]

1.4 Relevant background

1.4.1 Control of system frequency following a contingency event

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 can be considered through the following three-part framework:

1. The initial 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.

Initial RoCoF

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

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

- constrain generator output or interconnector flow to minimise the size of the contingency; and/or
- increase the level of inertia in the system to resist the initial rate of frequency change.

8 AGL, *Inertia Ancillary Service Market,* Rule change request, 24 June 2016, p. 4

For credible contingencies, AEMO has the ability to introduce constraints, in order to maintain system security, 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 on an interconnector may limit the ability of power to flow from a lower priced region to a higher priced region.

An alternative to constraining the system to limit the size of the contingency 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.

The Commission recently made a final rule relating to the *Managing the rate of change of power system frequency* rule change request which places an obligation on TNSPs to procure minimum levels of inertia. However, there is currently no mechanism for AEMO or any other party to obtain and pay for additional inertia for market benefit. In the past, inertia has been plentiful and so such a mechanism has not previously been required

Restoring frequency

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

Currently, AEMO is able to procure FCAS, to maintain frequency within defined limits set out in the FOS. 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. The current fastest contingency FCAS operates over a timeframe of up to six seconds.

To permit a greater potential 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”. FFR services are faster than the existing six-second service and would provide greater flexibility in the level of RoCoF that could be permitted. The Commission consequently considers that managing frequency in a low inertia system should aim to facilitate the use of fast-frequency technologies and to be able to effectively co-optimise the provision of these services with the provision of inertia.

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 slows 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 above a minimum threshold level to stabilise system frequency.

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 all parts 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 individual 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).[9] 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 the RoCoF exceeds those levels, even if the frequency remains within the bounds of the FOS.

1.4.2 Levels of inertia required to manage power system security

As new non-synchronous generating technologies achieve greater levels of penetration, a higher level of RoCoF will be experienced for a given contingency event, and there will be less time available to arrest the increase or decrease in frequency before it moves outside of permitted operating bands.

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

1. **Minimum level of inertia**[10] – The minimum level of inertia that is required to maintain in a secure operating state the portion of the system that could become islanded as a result of a separation contingency event. This represents a lower bound on the level of inertia that is required to feasibly operate the system. Operating at this minimum level may require load shedding but would be sufficient to maintain the islanded system in a satisfactory operating state and

9 Schedule 5.2.5.3 of the NER.

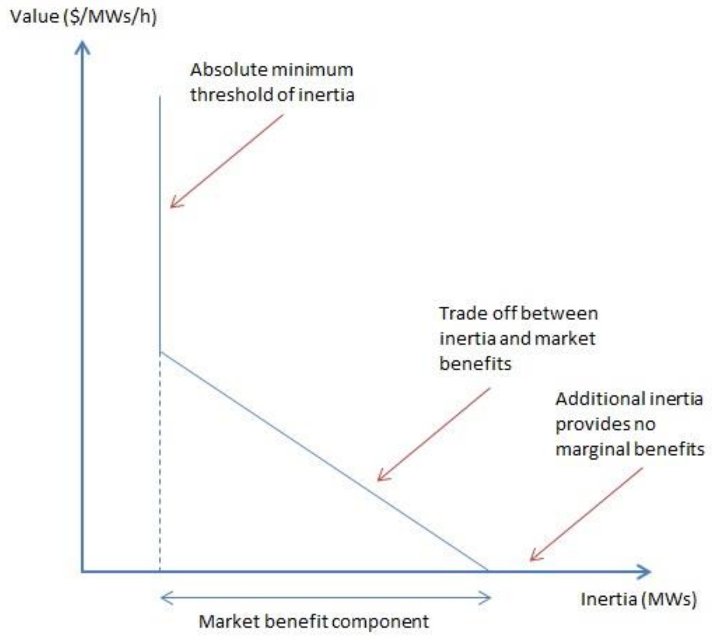
10 The minimum level of inertia has been addressed through the *Managing the rate of change of power system frequency* final rule, which commences on 1 July 2018.

avoid a system black condition. This minimum level might permit only limited interconnector flow, prior to separation.

2. **Market benefits** – Additional inertia above the minimum level of inertia would allow for a more unconstrained operation of the islanded system or additional interconnector flows when not islanded. This would provide benefits of improved reliability and a lower overall cost of energy provision by alleviating constraints on the system.

The split between these two components is illustrated in Figure 1.1, which shows a theoretical demand curve for inertia.

Figure 1.1 Value of inertia and the amount of inertia provided



The vertical line on the left represents the minimum level of inertia that is required to maintain the islanded system in a satisfactory operating state. This vertical line is a lower bound on the level of inertia that could feasibly be required in order to operate the system within the FOS and maintain a satisfactory operating state when operating the system as an island. 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 or obtaining FFR services. 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, improving reliability, or lowering the overall cost of energy production.

Figure 1.1 represents a theoretical trade-off between increasing levels of inertia and obtaining market benefits. This trade-off is unique to the specific set of operating conditions present in the system at a given point in time. In practice, the level of inertia required to limit RoCoF and maintain the secure operation of the power system varies with changing system conditions.

Section 3.1 outlines in more detail the distinction between the minimum required levels of inertia and the market benefit level of inertia.

1.5 The rule making process

On 8 September 2016, the Commission published a notice advising of its commencement of the rule making process and consultation in respect of the rule change request.[11] A consultation paper identifying specific issues for consultation was also published. Submissions closed on 13 October 2016.

On 15 December 2016, the Commission published its interim report to the COAG Energy Council on the System security market frameworks review. The interim report set out the Commission's preliminary findings and canvassed a number of options to obtain system security services to address the potential for high rates of change of frequency arising from reduced levels of inertia. Submissions closed on 9 February 2017.

On 23 March 2017, the Commission published a directions paper on the System security market frameworks review. The directions paper presented the Commission's proposed approach to address the management of system frequency with reduced levels of synchronous generation. Submissions closed on 20 April 2017.

On 27 June 2017, the AEMC published its final report on the System security market frameworks review. One of the recommendations in the report was to introduce a market based mechanism to realise the benefits that could be obtained through the provision of inertia.

All of these documents, and submissions to them, are available on the AEMC website.[12]

On 5 September 2017, the Commission published a further consultation paper seeking stakeholder feedback on a specific market-mechanism to reward the value of inertia. Submissions closed on 3 October 2017.

The Commission received 17 submissions in response to this consultation. The Commission considered all issues raised by stakeholders in submissions. Issues raised in submissions are discussed and responded to throughout this draft rule determination.

1.6 Structure of draft rule determination

This draft rule determination is set out as follows:

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11 This notice was published under s. 95 of the National Electricity Law (NEL).

12 Available at: http://www.aemc.gov.au/Markets-Reviews-Advice/System-Security-Market-Frameworks-Review

- Chapter 2 sets out a summary of the Commission's draft rule determination, including its assessment framework and summary of reasons for not making a draft rule.
- Chapter 3 explores the rationale for not introducing a market mechanism for the provision of additional inertia for market benefit at this time
- Chapter 4 outlines the focus of the AEMC's work program for the development of an inertia market mechanism in the future and the potential integration with markets for other frequency control services
- Appendix A provides additional information on maintaining the power system in a secure operating state
- Appendix B provides the Commission's response to stakeholder comments that are not addressed elsewhere in the draft rule determination
- Appendix C sets out the relevant legal requirements under the NEL for the Commission to make this draft rule determination.

1.7 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination by 19 December 2017.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 14 November 2017.

Submissions and requests for a hearing should quote project number ERC0208 and may be lodged online at www.aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

2 Draft rule determination

2.1 The Commission's draft rule determination

The Commission supports the development of competitive markets for the provision of system services for achieving the most efficient outcomes for consumers. However, given the current power system operating conditions, the need to understand practical outcomes from new regulatory frameworks recently introduced and assess outcomes from various Commission and AEMO programs of work on foot, the Commission is not satisfied that introducing a market sourcing mechanism for inertia will, or is likely to, contribute to the achievement of the NEO at this time but does consider that such a mechanism could meet the NEO in the future.

This chapter sets out the reasons as to why the Commission's draft rule determination is not to make a draft rule at this time.

This chapter also outlines the rule making test for changes to the NER and the assessment framework for considering the rule change request.

Further information on the legal requirements for making this draft rule determination is set out in Appendix C.

2.2 Rule making test

2.2.1 Achieving the national electricity objective

The Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[13] This is the decision making framework that the Commission must apply.

The NEO is:[14]

> “to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.”

13 Section 88 of the NEL.

14 Section 7 of the NEL.

2.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered the following principles:

- **Risk allocation:** The provision of additional inertia above the minimum level would allow for a more unconstrained operation of the islanded system or additional interconnector flows when not islanded, creating market benefits for consumers. However, there are costs associated with procuring additional inertia.

  A trade-off exists between the costs incurred for providing additional inertia for a more unconstrained operation of the system and the benefits of improved reliability and a lower overall cost of energy to consumers.

  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, resulting in increased costs. Solutions that allocate risks to market participants, such as businesses who are better able to manage risks and balance costs, are preferred where practicable.

- **Market mechanisms:** Competition and market signals, where feasible, generally leads to more efficient operational and investment decisions than prescriptive rules and central planning. These outcomes are generally more flexible to changing market conditions and provide consumers with the services in the most efficient manner possible. For competition to be effective, it must be able to deliver market signals to parties best able to respond to these signals in a manner that benefits consumers.

- **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.[15] 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.

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

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15 Investment refers to both certainty of initial investment and return on ongoing investment

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

- **Technology neutral:** Regulatory 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.

2.4 Summary of reasons

The Commission has assessed whether the proposed rule change request will, or is likely to, contribute to the achievement of the NEO and has evaluated the proposed rule change request against the assessment framework set out above.

The Commission considers that a market-based mechanism is likely to be the most efficient means of delivering the market benefits aspect of inertia. One of the Commission’s key principles is that competition and market signals generally lead to better outcomes than centralised planning, since they are more flexible to changing conditions and to consumers’ needs.

Additional inertia above the minimum level associated with maintaining system security would allow power to flow on the system in a less constrained way, potentially reducing market energy prices. The levels of inertia required to remove all constraints are highly variable. Consequently, using a market-based mechanism that puts a price on inertia to unlock these market benefits would allow market participants to co-optimise their provision of inertia and energy, minimising overall costs.

However, while a complementary mechanism to facilitate additional inertia for market benefit would likely contribute to the NEO, given the current power system operating conditions, the need to understand practical outcomes from new regulatory frameworks recently introduced and assess outcomes from various Commission and AEMO programs of work on foot, the Commission is not satisfied that introducing a market sourcing mechanism for inertia will, or is likely to, contribute to the achievement of the NEO at this time.

In light of views expressed by stakeholders in submissions, and further analysis undertaken on the benefits of the introduction of an inertia market mechanism, the Commission has determined not to make a draft rule with respect to AGL’s rule change request for the following reasons:

1. The minimum levels of inertia required to maintain the system in a secure operating state has been addressed through final rules on the South Australian Government's rule change request on *Managing the rate of change of power system frequency*. Therefore, concerns around guaranteeing the continuous availability of

minimum levels of inertia has been addressed, reducing the urgency for realising market benefits from the provision of additional inertia above this minimum level.

2. The minimum levels of inertia required to maintain the system in a secure operating state will be determined by AEMO over the next eight months. . The obligation on AEMO to determine the minimum levels of inertia does not extend to the identification of market benefits that can be obtained through the provision of additional inertia. However, once the minimum levels of inertia are determined, the extent to which price signals exist to accurately reflect the value of inertia are likely to be more evident.

   The delivery of accurate price signals allows parties best able to deal with these signals to respond in a manner that encourages competition and benefit consumers. Appropriate price signals are required to encourage efficient operational and investment decisions.

3. The application of constraints by AEMO to manage low system strength issues in South Australia has had a consequential impact on the alleviation of the inter-regional RoCoF constraint on the Heywood Interconnector, suggesting limited market benefits could be obtained from additional inertia at this time.

4. Further consideration needs to be given as to how inertia can be accurately valued with the application of constraints to manage other system security requirements, such as system strength and system stability, and with the provision of alternative frequency control services, such as FFR.

   AEMO is working to further understand the limits of power system operation with low levels of synchronous capability and is considering how system security constraints can be developed to address these issues in a holistic manner.

   Going forward, new technologies that have the potential to provide new, faster frequency control services will become increasingly important as a complement to, and partial substitute for, inertia. The Commission considers that delaying the introduction of a market mechanism for additional inertia for market benefit allows the design of an appropriate market to be refined and potentially be co-optimised with other new markets such as FFR.

   The Commission's final rule relating to the *Managing the rate of change of power system frequency* rule change request allows TNSPs to procure other services such as fast frequency response to reduce the minimum level of inertia required.

   The Commission considers that in the absence of a greater understanding of the practical outcomes from new regulatory frameworks recently introduced and outcomes from various Commission and AEMO programs of work on foot risks putting in place new markets or requirements that are not carefully designed which may result in customers or market participants bearing unnecessarily higher costs for the development of a new market which does not present value at this time.

The Commission considers that the introduction of a market mechanism for additional inertia for market benefit is the most efficient means to meet the NEO, to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price and security of supply of electricity.

However, given the current power system operating conditions, the need to assess outcomes from the program of work on foot, both that of the Commission's and AEMO's, and having regard to the issues raised during consultation, the Commission is not satisfied that the proposed rule will, or is likely to, contribute to the achievement of the NEO at this time but does consider that it could meet the NEO in the future.

Accordingly, the Commission’s draft rule determination is to not make a draft rule. However, the Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*. Recommendations arising from this review will be published in mid-2018.

3 The introduction of a market mechanism for inertia

Competitive market mechanisms are always the Commission's preferred approach for achieving the most efficient outcomes for consumers.

However, the design and implementation of a market mechanism for additional inertia for market benefit requires careful consideration in order to facilitate the efficient allocation of risk across participants and to allow for the development of a competitive environment.

It is also important that the need for a new market mechanism is established, particularly at a time when the energy market is rapidly evolving.

This chapter outlines:

- the distinction between the minimum required levels of inertia and the market benefit level of inertia and identifies current market benefit opportunities in the NEM
- an assessment of the need for a market mechanism for additional inertia for market benefit at this time.

3.1 The provision of inertia through a market mechanism

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

1. **Minimum level of inertia** – The minimum level of inertia that is required to maintain the islanded system in a satisfactory operating state represents a lower bound on the level of inertia that is required to feasibly operate the system.
2. **Market benefits** – Additional inertia above the minimum level of inertia would allow for a more unconstrained operation of the islanded system or additional interconnector flows when not islanded. This would provide benefits of improved reliability and a lower overall cost of energy provision by alleviating constraints on the system.

On the 19 September 2017, the Commission made a final rule relating to *Managing the rate of change of power system frequency* rule change request. The final rule places an obligation on TNSPs to procure minimum levels of inertia or procure other services such as frequency control services that reduce the minimum level of inertia required.

A market mechanism for inertia would be designed to facilitate the efficient provision of additional inertia in order to maximise market benefits.

3.1.1 Minimum required levels of inertia

The final rule relating to the *Managing the rate of change of power system frequency* rule change request provides a high degree of confidence that system security can be maintained when separation and islanding of sub-networks occurs. .

Determining the minimum required levels of inertia

The minimum inertia requirement is made up of two separate levels of inertia:

1. The minimum threshold level of inertia - the minimum threshold level of inertia required in order to maintain the islanded region in a satisfactory operating state should it be separated from the rest of the NEM

2. The secure operating level of inertia - once separation has occurred, the higher level of inertia required for the continued operation of the islanded region in a secure operating state.

Clause 4.2.2 in the NER defines the conditions under which a system is considered as being in a satisfactory operating state. There are a range of technical parameters that must be maintained within satisfactory limits, including a requirement that the system frequency is within the normal operating frequency band.

The minimum threshold level of inertia is sufficient to maintain the islanded region in a satisfactory operating state should it become separated. However, it is not sufficient to maintain a satisfactory operating state should a further credible contingency occur. A credible contingency of even a moderate size would likely cause the system frequency to move outside the bounds of the FOS, potentially resulting in cascading loss of generation and a system black event.

Therefore, once separation has occurred, the continued operation of the islanded system requires a higher level of inertia to be provided. This level of inertia should be sufficient to enable AEMO to return the islanded system to a secure operating state.

The level of inertia required to maintain the islanded region in a secure operating state would be based on a consideration of three different factors:

1. *Availability and capability of contingency FCAS* - The capabilities and expected response times of contingency FCAS in the islanded region would determine the maximum RoCoF that could be managed without the frequency moving outside the bounds of the FOS. Inertia does not act to stop the frequency drop entirely or revert frequency back to normal operating levels. Inertia slows the rate of frequency change and so provides time for contingency FCAS to operate

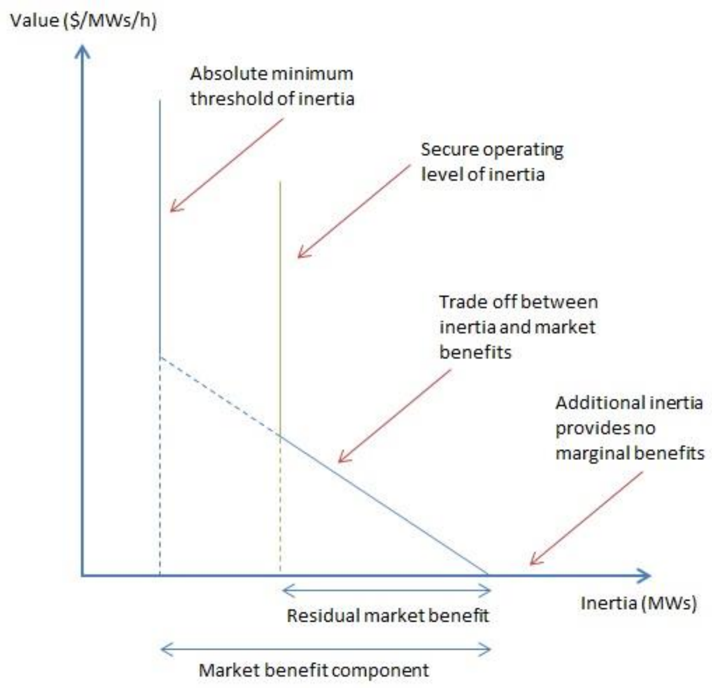
2. *Maximum contingency size* - The maximum expected contingency size when operating as an islanded system would also influence the level of inertia required. A larger contingency size results in a higher RoCoF for a given level of inertia. It is likely that the operation of the system as an island would require the system to be operated in a specific highly constrained state, which would likely

mean a lower potential contingency size as the majority of generating units would be operating at their minimum output

3. *Possible further loss of inertia* - Additional inertia needed to account for the possible loss of a synchronous generating unit. The RoCoF that occurs as a result of a contingency event would be even higher if the contingency that occurs is the loss of a synchronous generating unit that is also providing inertia.

Figure 3.1 shows the secure operating level of inertia in relation to the minimum system threshold level of inertia.

Figure 3.1 The minimum threshold level and the secure operating level



Final rule to provide minimum required levels of inertia

The final rule made with respect to the South Australian Government's *Managing the rate of change of power system frequency* rule change request places an obligation on TNSPs to procure the minimum levels of inertia, or alternative frequency control services, required to maintain the secure operation of the power system.

The key features of the final rule are as follows:

- An obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island and, for each sub-network, to:
  - determine the minimum required levels of inertia; and
  - assess whether a shortfall in inertia exists or is likely to exist in the future.

- Where an inertia shortfall exists in a sub-network, an obligation on the relevant TNSP[16] to make continuously available minimum required levels of inertia, determined by AEMO. The TNSP can provide the inertia itself or procure inertia services from third parties such as generators.

- An ability for TNSPs to invest in or contract with third-party providers of alternative frequency control services ("inertia support activities"), including FFR services, as a means of reducing the minimum required levels of inertia, with approval from AEMO.

- An ability for AEMO to enable the inertia network services provided by TNSPs and third-party providers under specific circumstances in order to maintain the power system in a secure operating state.[17]

An obligation on TNSPs to make minimum levels of inertia continuously available will provide a high degree of confidence that system security can be maintained when separation and islanding of sub-networks occurs.

The requirement for TNSPs to identify the least cost option, or combination of options, to provide the minimum levels of inertia, together with the existing economic regulatory framework for TNSPs, will provide discipline on the level of expenditure on inertia network services by enabling the AER to assess the efficiency of that expenditure, and will provide a greater ability to coordinate the provision of inertia with other network support requirements, such as system strength.

3.1.2 The provision of inertia to realise market benefits

Beyond the minimum levels of inertia required to maintain the system in a secure operating state, a market mechanism for inertia could facilitate the efficient provision of additional inertia in order to maximise market benefits.

Level of additional inertia for market benefit

The secure operating level of inertia would only be sufficient to operate the islanded system under specific highly constrained conditions. A higher level of inertia would provide market benefits by either:

- enabling the secure operation of the islanded sub-network under a much larger range of system conditions; or

- when not operating as an island, allowing for greater flows on the interconnectors with adjacent sub-networks.

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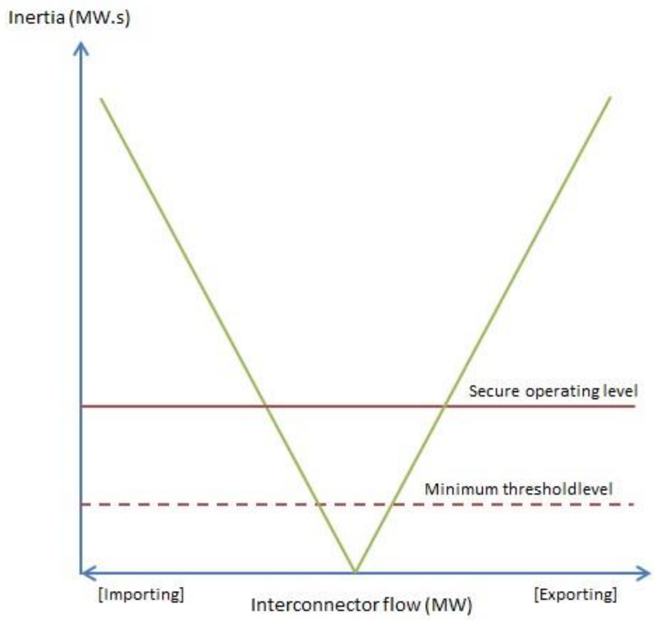
16 AEMO is responsible for planning, authorising and directing augmentation of the declared shared network in Victoria. Different arrangements for the provision of shared transmission services, including inertia network services, will apply to AEMO in its role as the Inertia Service Provider for Victoria.

17 An inertia network service is enabled when AEMO has selected the relevant inertia network service and the service is providing inertia to an inertia sub-network.

Figure 3.2 shows the absolute minimum threshold level of inertia (broken red line) and the secure operating level of inertia (solid red line) in comparison to the level of additional inertia that would allow for increased flows on the interconnector (green line). The provision of only the minimum levels of inertia would require the interconnector to be constrained. Additional inertia would allow for the alleviation of constraints and higher flows on the interconnector for a given limit on the RoCoF that would occur from a sudden separation of the interconnector.

Figure 3.2 Comparison of minimum required levels of inertia and additional inertia for market benefit



3.1.3 Current opportunities for market benefit of inertia in the NEM

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 installation of non-synchronous generation relative to its total generation capacity. In addition, a number of conventional synchronous generators have recently retired.

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.

On 4 October 2016, AEMO introduced constraints to limit the RoCoF to below 3 Hz/sec for the non-credible coincident trip of both circuits of the Heywood Interconnector, following a direction issued by the South Australian Minister.[18] The effect of the constraint has been to limit flows on the Heywood Interconnector.

The rationale for the implementation of a market mechanism for inertia has been alleviation of the inter-regional RoCoF constraints on the Heywood interconnector between South Australia and Victoria where there has likely been a market benefit from doing so. Additional inertia online in South Australia provides potential market benefits by allowing for greater flows on the interconnector while still limiting the RoCoF to 3 Hz/sec should the interconnector suddenly fail.

3.2 AGL's view

AGL considers that the changing mix of generation capacity in the NEM has led to a decreasing supply of inertia, and that inertia, as an increasingly scarce service, should be appropriately valued in the market.[19]

AGL proposes that procurement of inertia should occur on a competitive basis through a tender contract process conducted by AEMO. AEMO would administer the procurement and determine the quantity of inertia to be contracted. AEMO would conduct the tender/auction process, determine any relevant terms and conditions, and the timeframes for the inertia to be procured.

However, in response to the AEMC's consultation paper, AGL considers that further analysis is required to assess whether an inertia market mechanism is required at this time. AGL's submission sets out a number of reasons as to why a market for inertia may not be appropriate at this time including its interaction with:

- the introduction of an obligation on TNSPs to provide the minimum levels of inertia through the AEMC's *Managing the rate of change of power system frequency rule change*, and
- other recent changes to system security requirements including those being set by the South Australian Office of the Technical Regulator, the South Australian Government’s own investments in battery storage capability, diesel generation capacity and open cycle gas turbines and AEMO’s market management given wind levels in South Australia.[20]

In addition, AGL is not convinced that the use of an obligation on TNSPs for the minimum inertia levels coupled with a market mechanism will operate efficiently.[21]

18 The power for the South Australian Minister to issue this direction arises under South Australian legislation.

19 AGL, *Inertia Ancillary Service Market,* Rule change request, 24 June 2016, p. 3

20 AGL, Submission on the consultation paper, p. 1

21 AGL, Submission on the consultation paper, p. 2

3.3 Stakeholders' views

The introduction of a market mechanism for additional inertia for market benefit at this time

Stakeholders are largely in support of the development of markets to value system services.

Origin Energy considers that a market mechanism for inertia where generators can make commitment decisions based on clear price signals, will enable inertia to be provided at the least cost to the consumers.[22]

Tesla also supports a market based mechanism which has the ability to evolve over time to ensure the most capable and cost-effective technologies are providing the required inertia.[23]

The Public Interest Advocacy Centre (PIAC) consider that monetising and rewarding some system services may be warranted. However any rule change which impacts on consumer costs must be justified by demonstrably better outcomes for consumers through being based on their actual willingness to pay.[24]

While stakeholders generally support markets for inertia, many are not convinced of a clear or compelling need for the development of a market mechanism for inertia at this time. A number of stakeholders have suggested delaying the introduction of a market for inertia until after the AEMC's *Frequency control frameworks review* is finalised in mid-2018.

Meridian Energy suggests that the Australian energy market is undergoing fundamental change and it would be inappropriate to introduce a new complex market unless there was a clear compelling need and/or the benefit clearly outweighed potential costs.[25]

Energy Australia[26] and the Australian Energy Council[27] raise concerns that this rule change should not be progressed ahead of a more holistic review of frequency management.[28]

AEMO supports the development of market frameworks for valuing and unbundling the components of a secure, reliable and efficient system.[29] However, it considers that

22 Origin Energy, Submission on the consultation paper, p. 1

23 Tesla Motors Australia Pty Ltd, Submission on the consultation paper, p. 2

24 PIAC, Submission on the consultation paper, p. 1

25 Meridian Energy, Submission on the consultation paper, p. 2.

26 Energy Australia, Submission on the consultation paper p. 1

27 Australian Energy Council, Submission on the consultation paper p. 1

28 Energy Australia, Submission on the consultation paper, p. 2

29 AEMO, Submission on the consultation paper, p. 3

the presence of a price signal requires the appropriate elements for an efficient market to exist. AEMO considers that these elements are not apparent currently.

The minimum levels of inertia are unknown

Meridian Energy suggest that the introduction of a new market may not be appropriate at this time given that inertia management is still being developed.[30]

S&C Electric propose that issues around governor response and deadband settings should be addressed in advance of the creation of a new market.[31]

AEMO suggest that as they are currently assessing the system strength requirements for South Australian under recent AEMC *Managing the rate of change of power system frequency* and *Managing power system fault levels* rule changes, the outcome of which will better allow the gap for market benefits to be identified.[32]

System strength constraints have reduced the main economic benefit

AEMO highlight in its submission that as a result of a recently implemented system strength constraint to provide sufficient fault level to maintain a secure operating state, the inter-regional RoCoF constraint on the Heywood Interconnector has not been binding to the same extent as it did in the past.[33] This suggests that the provision of additional inertia would not provide any additional economic benefit by allowing for the alleviation of the inter-regional RoCoF constraint and the provision of greater power transfer capability between South Australia and Victoria.

While AGL's rule change request specifically relates the introduction of a market mechanism for inertia, AEMO suggests that market benefits may be achieved in the short term by delivering additional synchronous capability to alleviate the system strength constraint which has been applied to limit non-synchronous wind generation in South Australia, rather than the inter-regional RoCoF constraint. An increase in the provision of inertia from synchronous generating units would also increase the levels of system strength in South Australia, which would allow for greater non-synchronous wind generation at times.

However, AEMO acknowledges that the alleviation of the system strength constraint requires synchronous capability in specific locations and for specific combinations of generating plant. In this case, it would be difficult to derive a marginal price that would accurately reflect the value of bringing specific generation online.

30 Meridian Energy, Submission on the consultation paper p. 2

31 S&C Electric, Submission on the consultation paper, p. 1

32 AEMO, Submission on the consultation paper, p. 4

33 AEMO, Submission on the consultation paper, p. 4

3.4 Assessing the need for an inertia market mechanism at this time

The introduction of a market mechanism to realise the market benefit of inertia requires careful consideration to establish whether there is a compelling need for its introduction at this time. The Commission has considered a number of principle factors in its assessment:

1. The minimum levels of inertia required to maintain the system in a secure operating state has been addressed through final rules on the South Australian Government's rule change request on *Managing the rate of change of power system frequency*. Therefore there is less urgency associated with the provision of additional inertia above this minimum level

2. The minimum levels of inertia required to maintain the system in a secure operating state will be determined by AEMO over the next eight months. The level of the minimum inertia requirement will determine the extent to which there is any residual market benefits to be obtained from additional inertia.

3. The application of system strength constraints by AEMO to manage low system strength issues in South Australia has had a consequential impact on the alleviation of the inter-regional RoCoF constraint on the Heywood Interconnector, suggesting limited market benefits could be obtained from additional inertia at this time.

3.4.1 Minimum levels of inertia required for system security have been addressed

The Commission's final rule for the *Managing the rate of change of power system frequency* rule change request, relates to the provision by TNSPs of the minimum level of inertia required to maintain secure operation of the power system. This can be distinguished from additional levels of inertia that may increase economic benefits by allowing for greater power transfers on the network, such as greater energy flows on interconnectors.[34]

An obligation on TNSPs to make minimum levels of inertia continuously available will provide a high degree of confidence that system security can be maintained.

The final rule does not provide a mechanism to realise the market benefits that could be obtained above the minimum level of inertia. However, these additional levels of inertia do not need to be continuously available in order to make sure that system security can be maintained. Instead, an economic trade-off exists between the costs of providing this additional inertia and the lower overall costs of energy production obtained through a less constrained operation of the power system. Additional inertia provided above the minimum level is less about maintaining the secure operation of the system and more about making sure that the efficient capability of the network is utilised in order to lower overall costs to consumers.

34 See section 3.1 for a detailed discussion on this.

However, the overall costs to consumers will only be lowered if the costs of providing additional inertia are lower than the market benefits that can be obtained through greater power transfers on the network. Therefore, the Commission considers that a market-based mechanism is likely to be more appropriate to deliver the market benefit aspect of inertia. However careful design of this mechanism is necessary in order to make sure that the potential economic benefits are realised in an efficient manner.

3.4.2 Minimum levels of inertia are to be determined by AEMO

The final rule made by the Commission relating to the *Managing the rate of change of power system frequency* rule change places an obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island and, for each sub-network, to:

- determine the minimum required levels of inertia; and
- assess whether a shortfall in inertia exists or is likely to exist in the future.

The implementation of the final rule requires that AEMO must publish the inertia requirements methodology by 30 June 2018, setting out the process it will use to determine the inertia requirements for each inertia sub-network. AEMO must also make a determination of the inertia requirements for each inertia sub-network by 30 June 2018 applying the initial inertia requirements methodology.

A similar requirement has been applied to AEMO under the final rule on the South Australian Government's *Managing power system fault levels* rule change request[35] in relation to minimum levels of system strength.

It is not clear at this stage what the minimum required levels of inertia and system strength will be. However, this will have an impact on the extent to which there is residual market benefit to be obtained from the provision of additional inertia above this level.

The minimum required levels of inertia are likely to be relatively low as they are intended only to be sufficient to maintain the islanded system in a secure operating state under specific highly constrained conditions.

However, power system equipment that provides inertia, such as synchronous generating units and synchronous condensers, also provides system strength. Depending on the size of the minimum required levels of system strength, it is possible that some additional inertia may be provided by virtue of meeting the minimum system strength requirement. This additional inertia may provide for some consequential market benefit by allowing for a more unconstrained operation of the power system.

35 AEMC, *Managing power system fault levels* - Rule determination, 19 September 2017.

Another issue which may also contribute to the size of the minimum inertia requirement is the recent decline in NEM frequency performance which has correlated with changes to governor settings on generating plant. This issue was identified as part of the AEMC's *System security frameworks review* final report[36] and is being progressed as part of the *Frequency control frameworks review* which will examine the potential consequential impacts of reintroducing mandatory governor response requirements.

As AEMO is currently assessing the minimum inertia requirements, other aspects of the market and regulatory frameworks relevant to the system's inertia levels may change therefore the Commission considers it may be premature to introduce a market mechanism for additional inertia for market benefit until these factors are known. Until they are known the extent of the residual market benefit level is unclear.

3.4.3 System strength constraints have reduced the main economic benefit

As previously discussed in section 3.1.3, there has likely been some market benefit opportunities in South Australia for the alleviation of the inter-regional RoCoF constraint. However, the recent application of system strength constraints in South Australia has meant that the RoCoF constraint has not bound, reducing the potential market benefit that could be obtained through the provision of additional inertia.

Figure 3.3 shows the percentage of instances that the RoCoF constraint has bound on the Heywood Interconnector since October 2016. AEMO notes that the constraint has bound for 145 hours between 1 January and 27 May 2017, but has not bound since.[37]

The reason that the constraint has not bound since May is because AEMO has implemented a requirement in South Australia for a minimum level of synchronous generation to remain online at all times to address issues of low system strength. The minimum level of synchronous generation required to be online increases with the output of non-synchronous generation.[38]

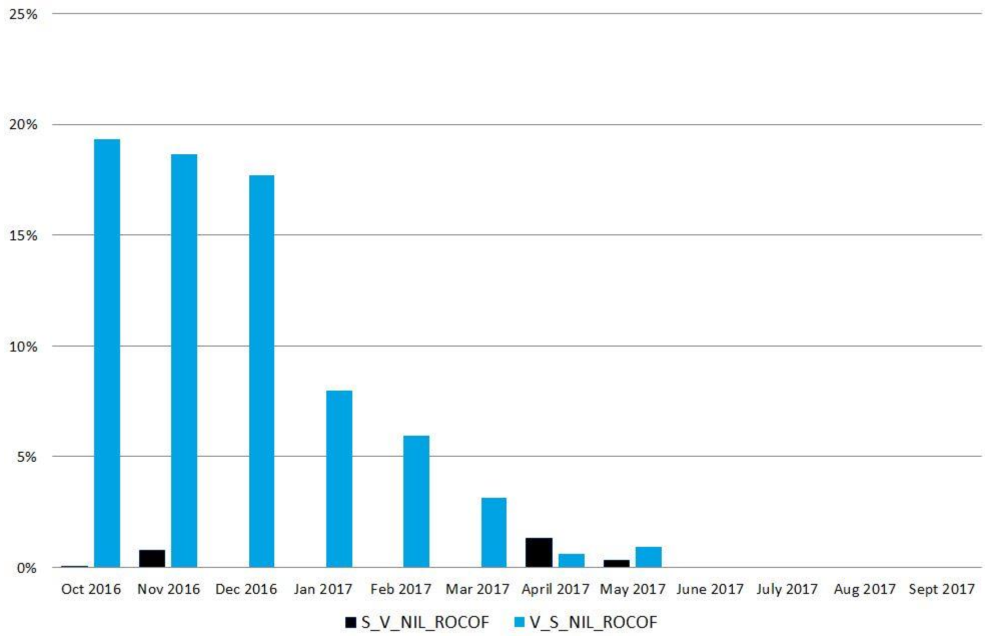
Prior to the application of this constraint, AEMO had implemented a minimum requirement equivalent to the two largest synchronous machines to remain online at all times. However, further detailed power system studies have identified that a more complex arrangement of synchronous machines must remain online in order to maintain sufficient system strength for various dispatch levels of non-synchronous generation. These updated constraints were first applied on 2 July 2017. AEMO's system strength constraints are discussed in Box 3.1.

36 The AEMC's *System security frameworks review* final report included a recommendation to "Assess whether mandatory governor response requirements should be introduced and investigate any consequential impacts (including on the methodology for determining causer pays factors for the recovery of regulation FCAS costs)".

37 AEMO, Submission on the consultation paper, p. 4.

38 AEMO, *South Australia System Strength Assessment*, September 2017, p. 5.

Figure 3.3 Percentage of time that a RoCoF constraint bound (where marginal value is not equal to zero)[39]



While the requirement for a minimum number of synchronous generators relates to maintaining minimum levels of system strength, the additional inertia provided by these generating units has meant that the Heywood interconnector has not bound since the system strength constraint was put in place.

This suggests that there may be limited economic benefit to be gained from the introduction of a market mechanism to provide additional inertia at this time.

AEMO notes that the constraints associated with the system strength requirement have bound for 355 hours between their introduction in early July 2017 and the end of September 2017.[40] Therefore, market benefits may be achieved in the short term by delivering additional synchronous capability to alleviate the system strength constraint rather than the inter-regional RoCoF constraint. However, the alleviation of the system strength constraint requires synchronous capability in specific locations and for specific combinations of generating plant. The Commission agrees with AEMO that it would be difficult to derive a marginal price bringing this additional capability online to alleviate the system strength constraint and allow for greater generation from non-synchronous wind.

To date, the focus for an additional inertia requirement has been on South Australia. It is not apparent at this stage, the extent to which other regions of the NEM may require the provision of additional inertia and therefore it is not clear that the alleviation of the

39 S_V_NIL_ROCOF refers to the RoCoF constraint on the Heywood interconnector flowing from South Australia to Victoria; V_S_NIL_ROCOF refers to the RoCoF constraint on the Heywood interconnector flowing from Victoria to South Australia.

40 AEMO, Submission on the consultation paper, p. 4.

inter-regional RoCoF constraints would provide an accurate value of inertia in regions other than South Australia.

As the generation mix changes, such as the increased penetration of non-synchronous generation and the subsequent retirement of large synchronous generating units, the requirements for inertia will also change. Inertia is likely to become more valuable into the future and therefore the development of a market mechanism for additional inertia for market benefit will be required to provide accurate price signals to promote efficient investment and to provide economic benefits to consumers.

Box 3.1 AEMO's system security constraints

AEMO has conducted power system studies to evaluate the adequacy of system strength for a range of operating conditions, including various levels of synchronous and non-synchronous generation, with normal operating conditions in South Australia.

This analysis has identified that a more complex arrangement of synchronous machines must remain online, to maintain sufficient system strength for various non-synchronous generation dispatch levels. In order to address low system strength in South Australia, AEMO has applied and maintained a system strength constraint since 2 July 2017.

The constraint introduces a requirement for minimum numbers of large synchronous generating units to be operating at all times in accordance with the level of non-synchronous wind generation online:

- Between zero and 1200 MW of wind generation, there must be three synchronous generating units online; and
- With more than 1200 MW of wind generation, there must be four synchronous generating units online.

The constraint acts to constrain back the level of wind generation, which allows for a higher proportion of synchronous generation to meet demand. At times, AEMO may also direct synchronous generators to come online.

Details of the technical analysis that supports these South Australian system strength requirements, and the permitted configurations of synchronous generating units, were published by AEMO on 6 September 2017.[41]

41 AEMO, South Australia System Strength Assessment, September 2017, p. 1.

4 Future development of markets for frequency control

While the Commission is of the view that introducing a market sourcing mechanism for inertia is unlikely to contribute to the achievement of the NEO at this time, it considers that further assessment of the nature of a market sourcing mechanism and the timing of its introduction is warranted, given the power system's evolving needs.

The Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*, in which the consideration of issues relevant to the nature of any such mechanism are currently underway.

This chapter sets out:

- the Commission's and stakeholders' views on the limitations of the market sourcing approach for inertia that was presented in the consultation paper published on 5 September 2017
- areas for further understanding of power system frequency in order to design a market mechanism for additional inertia for market benefit and to potentially incorporate the provision of alternative frequency control services.

4.1 The straw man market sourcing approach for inertia

In the consultation paper published on 5 September 2017, the Commission presented a straw man design for a market-based mechanism to reflect the value of inertia. This design was based around inter-regional RoCoF constraints.

The Commission understands that, in the near future at least, RoCoF constraints on the mainland are most likely to be applied on an inter-regional basis and, that by restricting flows between regions, these constraints are likely to have the greatest economic impacts. As the value of additional inertia to alleviate inter-regional RoCoF constraints is related to the reduction in price separation between two regions, the straw man design option would reward inertia provision by making use of the inter-regional settlement residues (IRSRs) that accrue on interconnectors when a RoCoF constraint binds.

There are two principal components of the Commission's straw man market sourcing approach:

- A price for inertia based on the shadow price for the alleviation of a RoCoF constraint
- Payments to inertia providers through the use of IRSRs that accrue on an interconnector with a binding RoCoF constraint.

Shadow pricing

For every dispatch interval in the energy market, AEMO derives dispatch using the National Electricity Market Dispatch Engine (NEMDE) to bring supply and demand into balance.

An output, or by-product, of solving the dispatch program is the energy price for each region. The energy price is generally 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, while accounting for the presence of other constraints on the power system.

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

In the presence of RoCoF constraints, which are limited by the amount of inertia present, 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:

$$(25[\text{Hz}] \times \text{Heywood Flow [MW]})/(\text{RoCoF [Hz per second]}) \leq \text{Inertia [MWs]}$$

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, i.e. the value of inertia relates to the difference in the regional reference prices between South Australia and Victoria.

Inertia funding through inter-regional settlement residues

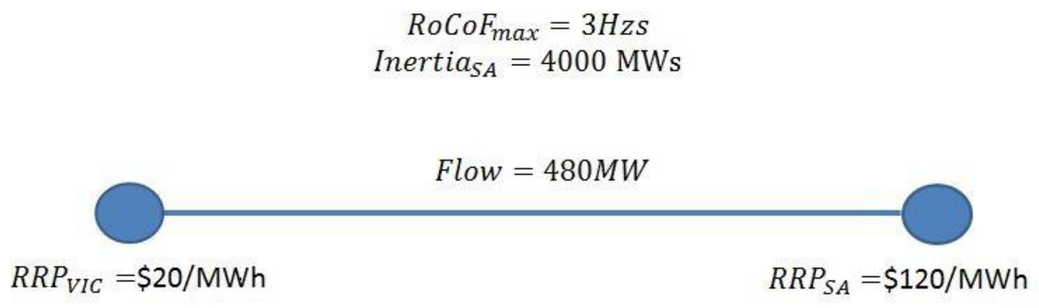
Inter-regional price separation occurs when interconnector capacity is limited and therefore insufficient to equalise the spot price by allowing enough power to flow from a lower to a higher priced region. If network conditions allow it, electricity flows from a lower price region toward a higher priced one. In an unconstrained network, with unlimited capacity, this would result in perfectly coupled prices in all regions, altered only by network losses. However, there is congestion in the NEM, and interconnectors do not always have enough capacity to allow for the equalisation of prices across regions.

When interconnectors are constrained, AEMO collects more money in the higher priced region (from consumers) than it needs to pay for the generation that has flowed from the lower priced region. The difference between the price paid in the importing region and the price received in the exporting region, multiplied by the amount of flow, is called an inter-regional settlements residue.

Where an inter-regional RoCoF constraint binds, the IRSR is equal to the shadow price of inertia (as discussed above) multiplied by the amount of inertia in the constrained region. This is because the provision of an additional one MW.s of inertia would allow an additional amount of inter-regional transfer, and hence the shadow price of inertia is derived from the inter-regional price separation in the same way that the shadow price of the constraint would be for any other type of constraint.

As an example, in the presence of 4000MW.s of inertia in South Australia, a RoCoF constraint on the Heywood Interconnector may bind at a flow of 480MW. Assuming the price separation between South Australia and Victoria is $100/MWh (and ignoring losses), the price of inertia can be calculated as:

$$\frac{480MW\ x\ \$100/MWh}{4000MWs} = \$12/MWs/h$$



Under the straw man mechanism, the IRSR funds accruing as a result of RoCoF constraints would be paid to inertia providers. Unlike the TNSP sourcing approach, all inertia providers would be eligible to provide the services, and would receive payments from settlement.

These payments would act as a signal to guide the enablement of inertia in the short term, and investment over the longer term. There would not be a separate inertia market, rather market participants would take expected inertia payments into account in structuring their energy market offers and making commitment decisions. Generators dispatched in the energy market who were providing inertia would receive inertia payments in addition to energy market payments.

At times of plentiful inertia, RoCoF constraints would not bind, there would be no inter-regional price separation and, hence, the inertia price would be zero. However, when RoCoF constraints bound, there would be a positive inertia price which would act to signal the value of inertia and encourage participants to provide additional inertia where the expected proceeds would exceed the incremental cost involved in doing so.

Limitations of the straw man funding approach

In the consultation paper, the Commission also noted that there are a number of reasons which may limit the effectiveness and efficiency of using the IRSR to fund inertia payments which may justify the adoption of an alternative approach. These reasons are summarised as follows.

- By transferring some IRSR funds away from settlement residue auction (SRA) units holders, this funding approach has the potential to reduce the effectiveness of SRA units as a means of hedging inter-regional spot price risk. This may require the development of alternative hedging products and may have the effect of delaying the potential timeframe for implementation of the straw man approach
- The straw man market sourcing approach would be introduced on the assumption that, at least in the near term, RoCoF constraints that restrict power flows between regions are likely to have the greatest economic impacts. However, the straw man funding approach using IRSRs would not address intra-regional RoCoF constraints or other types of constraints which are applied to manage system security.

4.2 The development of future markets for frequency control

The appropriate design of a market mechanism for additional inertia for market benefit will require further consideration of:

- the interaction of constraints to manage high RoCoF with other system security constraints
- how best to incorporate the value of alternative frequency control services.

Understanding the requirements of the power system

AEMO is working to further understand the limits of power system operation with low levels of synchronous capability. The potential challenges include issues of system security associated with high RoCoF but also include issues associated with low system strength and system stability.

AEMO considers that system security constraints to address these issues will need to be considered in a holistic manner.[42] Further investigation is required to ascertain if an appropriate mechanism to value system services such as inertia can be developed using the value of alleviating constraints as a proxy to capture this benefit. The development of constraints to accurately reflect the value of inertia will require power system modelling and analysis in order to more fully understand the physical requirements of the grid.

AEMO is best placed in its role as market operator to ascertain how an appropriate constraint could be developed that would be able to be used to reflect an efficient value of inertia.

42 AEMO, Submission to the consultation paper, p. 3

AEMO's ongoing system security work program will be a key input to the development of future mechanisms to accurately value the provision of inertia in light of other system security constraints and the provision of alternative frequency control services.

Incorporating other frequency control services

Building on recommendations outlined in the *System security frameworks review*, a key work stream of the *Frequency control frameworks review* is to consider how best to integrate FFR services offered by new technologies into the ongoing response to frequency control.

Inertia and FFR are distinct services which perform different roles in the management of system frequency. Inertia acts to slow the rate of frequency change caused by a contingency. This is different to FFR, which actively injects power or reduces consumption to stop the frequency change and revert the frequency back towards normal operating levels. Nevertheless, an increase in the speed and quantity of FFR services may reduce the amount of inertia that is needed in order to control power system frequency following a contingency event.

New technologies, such as wind farms and batteries, offer the potential for frequency response services that act much faster than traditional services, perhaps as quickly as a few hundred milliseconds. However, the time delay of FFR technologies therefore 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, FFR technologies have the potential to be used in combination with inertia to stabilise system frequency.

However, beyond the first few hundred milliseconds, there is a potential trade-off that exists between the costs of supplying more inertia and obtaining FFR services. Consequently, there is an opportunity to co-optimise the provision of FFR, inertia and existing FCAS, to lower overall cost arrangements.

Further analysis is required to determine the appropriate frameworks to allow these services to be co-optimised.

AEMO is undertaking work to consider in detail how a technical specification for a FFR service might be developed.[43]

FFR services have not yet been deployed on a widespread basis, with limited experience operating a FFR-type contingency service in international markets. Some of the limited examples include a two-second FFR service recently implemented in

43 AEMO, Fast Frequency Response Specification, Release of GE Energy Consulting Report, 15 March 2017, p. 2

Ireland (October 2016) and a one-second demand response service used in New Zealand.[44]

AEMO indicated that given the immaturity of these services, a process of learning facilitated by trials and experience is necessary.[45] This will help to inform the capabilities of FFR services to contribute to maintaining frequency control and assess the potential for integration of other system services such as inertia and existing FCAS.

4.3 AGL's view

AGL consider that greater consideration is required as to whether the need for a market mechanism for inertia exists at present, given:

- the introduction of an obligation on TNSPs to provide the minimum levels of inertia through the AEMC's *Managing the rate of change of power system frequency rule change*, and
- other recent changes to system security requirements including those being set by the South Australian Office of the Technical Regulator, the South Australian Government's own investments in battery storage capability, diesel generation capacity and open cycle gas turbines and AEMO's market management given wind levels in South Australia.[46]

AGL propose that modelling of scenarios could provide evidence as to the potential value of inertia in a non-islanded region which would inform the design of a market mechanism.[47]

4.4 Stakeholders' views

The use of RoCoF constraints to value inertia

Many stakeholders support the use of shadow pricing as a means to value inertia[48] however many also raise concerns around this approach.

AEMO suggests that a shadow price of inertia may not be sufficient to address all the physical requirements of the grid and a more holistic approach is required.[49]

44 DGA Consulting, International Review of Frequency Control Adaptation – Report for the Australian Energy Market Operator, 14 October 2016, pp. 89 & 111.

45 AEMO, Fast Frequency Response in the NEM - working paper , August 2017, p.21

46 AGL, Submission on the consultation paper, p. 1

47 AGL, Submission on the consultation paper, p. 2

48 HydroTas, Submission on the consultation paper, p. 1; ERM Power, Submission on the consultation paper, p. 3

49 AEMO, Submission on the consultation paper, p. 3

Energy Australia raise concerns that the use of a shadow price, where inertia is valued based on the size of the price separation when there is an interconnector constraint, could have distortionary impacts on the energy market.[50]

ENGIE suggest that a binding RoCoF constraint in one particular five-minute dispatch interval will be unlikely to be sufficient incentive for a participant to decide to commit.[51]

Inter-regional settlement residue to fund inertia payments

The majority of stakeholders raise concerns around the use of this funding approach.[52] Stakeholders consider that the impact of using the IRSR funds on the existing settlements residue auctions have the potential to degrade the effectiveness of SRAs and therefore reduce their usefulness in the ability to hedge against inter-regional price risk.

Many also consider that encouraging a hedging market for inertia would add unnecessary complexity to the design of the mechanism.[53]

Both Hydro Tasmania and TasNetworks note that the proposed design is not a NEM wide solution as it would be incompatible with market network service provider (MNSP) funding models.[54]

Alternative approaches

Some stakeholders propose alternative models for the provision of additional inertia for market benefit.

ERM Power suggests the use of a close to real time market similar to the provision for fast start generators. It also suggests the use of procured network support and control ancillary services (NSCAS) to be dispatched on a day ahead basis.[55]

AEMO recommends the introduction of a centrally managed contract market for inertia to ensure services are considered in a holistic manner and to allow TNSPs and other providers to compete on an equal footing.[56]

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50 Energy Australia, Submission on the consultation paper, p. 2

51 ENGIE, Submission on the consultation paper, p. 3

52 AGL, Submission on the consultation paper, p. 2; Meridian Energy, Submission on the consultation paper, p. 2; Snowy Hydro, Submission on the consultation paper, p. 2; Energy Australia, Submission on the consultation paper, p. 2; Origin Energy, Submission on the consultation paper, p. 1; ERM Power, Submission on the consultation paper, p. 3; Clean Energy Council, Submission on the consultation paper, p. 4; TransGrid, Submission on the consultation paper, p. 3

53 Australian Energy Council, Submission on the consultation paper, p. 2; AEMO, Submission on the consultation paper, p. 5

54 HydroTas, Submission on the consultation paper, p. 1; TasNetworks, Submission on the consultation paper, p. 2

55 ERM Power, Submission on the consultation paper, p. 1

56 AEMO, Submission on the consultation paper, p. 6

Future development and incorporation of other frequency control services

Many stakeholders raise concerns around the premature introduction of a market mechanism for additional inertia for market benefit and consider that a greater understanding of the design requirements of a new market is required to produce the most efficient outcomes for consumers. Many stakeholders have suggested delaying the introduction of a market for inertia until after the AEMC's *Frequency control frameworks review* is complete in mid-2018.

Meridian Energy suggests that further quantitative analysis is required to ascertain how a market for inertia may develop.[57] This is supported by Energy Australia[58] and the Australian Energy Council[59] who consider that this rule change should be delayed until a wider review of frequency management is undertaken.[60]

S&C Electric specifically proposes that further investigation around issues such as governor response and deadband settings should be addressed in advance of the creation of a new market.[61]

Snowy Hydro considers that a review of FCAS markets should be completed to allow for consideration around how the co-optimisation of all ancillary services could be developed.[62]

Reach Solar Energy advocates the completion of the trial AEMO is currently conducting in advance of further changes being introduced, namely the trial at Hornsdale 3 wind farm for the provision of ancillary services.[63] Reach Solar suggest that delaying implementation will also allow a greater understanding of international experiences to assist in market development in the NEM.[64]

AEMO suggest that further information is required to drive the efficient development of the power system.[65]

AEMO is working to further understand the limits of operation of a power system with very low levels of synchronous capability, and refine the definition of the various fundamental system needs. This includes unbundling needs so they can be identified, valued properly, provided when needed and have costs recovered efficiently.[66]

57 Meridian Energy, Submission on the consultation paper, p. 1

58 Energy Australia, Submission on the consultation paper, p. 1

59 Australian Energy Council, Submission on the consultation paper, p. 1

60 Energy Australia, Submission on the consultation paper, p. 2

61 S&C Electric, Submission on the consultation paper, p. 1

62 Snowy Hydro, Submission on the consultation paper, p. 3

63 Reach Solar Energy, Submission on the consultation paper, p. 4

64 Reach Solar Energy, Submission on the consultation paper, p. 4

65 AEMO, Submission on the consultation paper, p. 3

66 AEMO, Submission on the consultation paper, p. 3

AEMO consider that system security constraints need to be considered in a holistic manner. The development of constraints to accurately reflect the value of inertia will require that the physical requirements of the grid are considered to allow a market mechanism to operate effectively.[67]

4.5 Facilitating future development

The Commission has come to the view that a market-based mechanism would offer an open and transparent approach that would best facilitate competition in the provision of inertia. However, the Commission also recognises the views expressed in stakeholder submissions that there are a number of reasons which may limit the effectiveness and efficiency of the straw man market sourcing approach.

As discussed in section 4.1, the Commission identified that the use of IRSRs to fund payments for inertia may limit the effectiveness of SRAs to the extent that they are used to hedge inter-regional price risk. As part of its consultation paper, the Commission presented alternative funding approaches for inertia payments, which stakeholders also expressed views on, including the use of SRA proceeds, SRA proceeds plus additional funding from TUoS charges, or an additional charge on beneficiaries.

The Commission also explored some potential alternative options for the provision of additional inertia as part of the *System security market frameworks review*. This included some options proposed by stakeholders in response to the consultation paper, such as the centrally managed contract market suggested by AEMO.[68]

The Commission considers that there may be relevance in continuing to assess this option in the design of market mechanism for additional inertia for market benefit. However, the Commission also considers that such an approach may not be appropriate in this instance as it may be difficult to develop clear criteria by which AEMO could assess competing or disparate offers, and that consumers would likely bear the risks of any under or over-procurement.

The Commission intends to continue its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*. The Commission acknowledges that further work required to gain a greater understanding of the frequency requirements of the power system in advance of the introduction of a new market.

AEMO's work on the limits of power system operation will be a key input to the AEMC's *Frequency control frameworks review* which is considering the market and regulatory frameworks necessary to support better frequency control in the NEM.

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67 AEMO, Submission on the consultation paper,, p. 3

68 AEMO, Submission on the consultation paper, p. 5

The review will first consider the outcome of AEMO's work on recent frequency control performance related to generator governor control.[69]

The terms of reference for the review also include a longer-term reassessment of FCAS frameworks to be undertaken. The objective of this work will be to determine how to most appropriately incorporate FFR into FCAS markets and will also offer the opportunity to consider wider questions as to whether existing FCAS markets will remain relevant in terms of meeting the emerging needs of frequency control in the NEM. This, might for instance, include reconsidering the rationale for the specific services that currently exist, in addition to considering the case for additional services.

Going forward, FCAS may also increasingly need to be optimised against dynamic system characteristics, such as the presence of inertia in each dispatch interval. As outlined in section 3.4.3, it is not clear that additional inertia targeted at alleviating inter-regional RoCoF constraints is where the opportunities for market benefits now lie. However, as levels of inertia decline into the future, a level of inertia will be required to manage contingencies across the NEM as a whole (e.g. loss of the largest generator). Consequently, any long term review of FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS, with this potentially requiring the development of additional inertia services.

This analysis will provide a key input into establishing how inertia can be appropriately valued and integrated with existing market frameworks and alternative frequency control services such as FFR.

The *Frequency control frameworks review* will continue to be coordinated with the ongoing technical work being completed by AEMO on frequency control issues.

The Commission considers that a mechanism that guides the provision of additional inertia for market benefit could further contribute to the achievement of the NEO. However, such a mechanism requires careful design due to the potential impacts on the operation of the energy and ancillary services markets.

69 AEMO commissioned expert advice on the causes and impacts of deteriorating frequency control performance, for consideration by its Ancillary Services Technical Advisory Group. The Commission is considering the outcome of this work and its implications through the *frequency control frameworks review.*

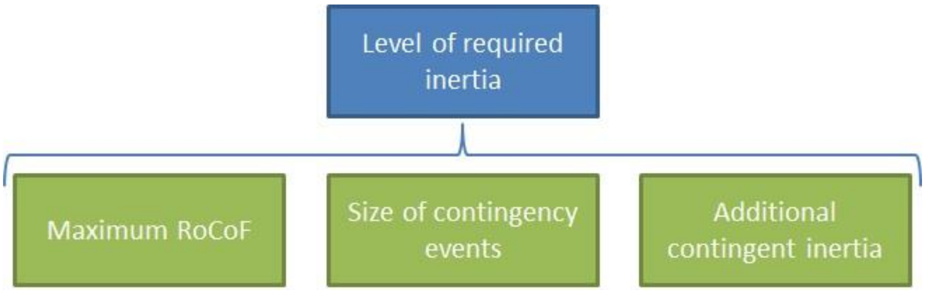
Abbreviations

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
MCE	Ministerial Council on Energy
MNSP	Market network service provider
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National electricity objective
NER	National Electricity Rules
NSCAS	Network support and control ancillary services
PIAC	Public Interest Advocacy Centre
RoCoF	Rate of change of frequency
SRA	Settlement residue auction
TNSP	Transmission Network Service Provider

A Maintaining the power system in a secure operating state

The level of inertia required to maintain an islanded region in a secure operating state is based on a consideration of a number of different factors:

Figure A.1 Factors that affect the secure operating level of inertia



Maximum RoCoF

The level of inertia required to maintain the islanded sub-network in a secure operating state would depend on the availability and capability of other frequency control services in the islanded system. The RoCoF would need to be limited to provide sufficient time for the fastest FCAS to respond and maintain the system frequency within the bounds of the FOS.

Contingency FCAS is controlled locally by generators and consists of technologies designed to detect and respond to larger frequency deviations that occur following contingency events.

The fastest existing contingency FCAS operates within timeframes of less than six seconds. However, it is likely that most of this contingency FCAS could operate over shorter timeframes. Specific analysis would need to be undertaken to determine the exact range and magnitude of response times from frequency control services in each sub-network.

Faster response services, such as FFR, could also increase the allowable RoCoF by providing much shorter response times. Less inertia would be needed to maintain the system frequency within the bounds of the FOS for a given contingency size.

Governor settings on generating plants also contribute to allowable RoCoF and affect the secure operating level of inertia.

Size of contingency events

The level of inertia required to limit the RoCoF is proportional to the size of the immediate shortfall in supply or demand arising from the contingency event. The larger the contingency event, the more inertia is required to limit the level of the RoCoF.

The maximum expected contingency size when operating the sub-network as an islanded system would influence the level of inertia required. It is likely that separation and islanding would require the sub-network to be operated in a highly constrained state. This would likely require some load shedding to occur and generating units to be constrained to their minimum operating output. As such, the maximum potential contingency size when operating as an island is likely to be substantially smaller than would be the case under normal operating conditions.

It is expected that the secure operating level of inertia would need to be large enough to account for a contingency equal to the largest minimum operating output from a single generating unit in the sub-network.

Additional contingent inertia

The secure operating level of inertia is intended to be able to maintain the sub-network in a secure operating state when islanded. This should mean that the islanded system can withstand the occurrence of a credible contingency within the sub-network and be able to maintain the system in at least a satisfactory operating state immediately following the contingency.

However, the likelihood of maintaining a satisfactory operating state would be greatly reduced if the contingency that occurs is the loss of a synchronous generating unit. Not only would the contingency event cause a change in the frequency but the ability of the system to dampen this change in frequency would be diminished by the loss of inertia from the synchronous generating unit.

Therefore, additional inertia will need to be provided to account for the possibility that the contingency that occurs is the loss of a synchronous generating unit. This additional inertia would be equal to the amount of inertia provided by an individual generating unit in the sub-network. This generating unit could be either:

- the generating unit providing the most amount of inertia to the system; or
- the generating unit with the highest minimum operating output, representing the largest contingency.

It is likely that the withstand capabilities of the generating units to high RoCoF would need to be taken into account in determining the specific individual generating unit.

B Summary of other issues raised in submissions

This appendix sets out the issues raised in stakeholder submissions on the consultation paper for this rule change request and the AEMC's response to each issue. If an issue raised in a submission has been discussed in the main body of this document, it has not been included in this table.

Stakeholder	Issue	AEMC Response
Alternative options		
Tas Networks	Further consideration should be given to model where inertia services can be contracted over a fixed period and dispatched in merit (cost) order depending on the marginal value of binding constraints. (p. 3) • The contracting model would be designed to dispatch supplementary capability necessary to make-up inertia shortfall coming from the energy dispatch process which results in binding constraints • relevant constraints would need to be clearly identified and appropriately formulated • the number and type of contracted inertia services could be reviewed annually and be based on the expected market benefits delivered over the forward analysis period • whether there is need for an associated TNSP incentive scheme and the treatment of synchronous generators dispatched in the energy market requires further consideration (p. 3)	The Commission acknowledges the proposed alternative approaches and intends to include them in its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*. AEMO is working to further understand the limits of power system operation with low levels of synchronous capability. The potential challenges include issues of system security associated with high RoCoF but also include issues associated with low system strength and system stability. AEMO considers that system security constraints to address these issues will need to be considered in a holistic manner. AEMO's work on the limits of power system operation will be a key input to the AEMC's *Frequency control frameworks review* which will examine the market and regulatory frameworks necessary to support better frequency control in the NEM.

Stakeholder	Issue	AEMC Response
Hydro Tas	Recommend a TNSP incentive scheme to contract for inertia on an annual basis. The scheme would provide the TNSP with an operational incentive to meet a targeted level of inertia (or a proportion of the time when RoCoF constraints should not bind). Hydro Tasmania believes that the TNSP's planning frameworks are able to set such targets and are able to forecast both the likely costs of inertia provision and the resulting benefits. These benefits could be quantified over the contract term with appropriate resets placed if market conditions were to change. Hydro Tasmania agrees that the TNSP incentive scheme should not be based on actual market outcomes. Hydro Tasmania believes this is a simpler approach and can be implemented using constraints: • A service provider is contracted for the provision of inertia based on an annual set fee agreed with the TNSP. This would include a base fee to maintain a minimum level of inertia for system security purposes and a further amount for market benefits • the service provider would be engaged to ensure a nominated set of constraints are alleviated, e.g. RoCoF from binding, and to ensure minimum inertia thresholds are always maintained (this approach can also later be broadened to apply for Fault Levels at defined connection points) • The service provider would only receive payment when the defined constraint sets are not binding for each of the minimum level and the market benefit provision for each 30 minute period (p. 2)	In relation to TNSP incentive schemes, the Commission noted in the *System security market frameworks review* that a market based mechanism is likely to be more appropriate to deliver the market benefit aspect, and would have significant advantages in that wholesale market participants, rather than TNSPs, would continue to make generator commitment decisions.
TransGrid	TransGrid consider that a broader range of options for the	

Stakeholder	Issue	AEMC Response
	provision of additional inertia should be considered such as a TNSP incentive scheme (p. 1)	
ENGIE	ENGIE proposes that a day ahead market could be considered for firming services including inertia. A day ahead market for firming services could be designed to allow AEMO to consider the forecast requirement for inertia and other firming services such as system strength and flexible ramping, for the upcoming day. Where particular generating units are required to be online to provide firming services, the firming services day ahead market would be used to allow potential service providers to indicate to AEMO in advance, their willingness and price to provide these services. AEMO would then select the cheapest combination of firming services to meet the forecast requirements, and produce a day ahead schedule to indicate which services are required, and when they need to be enabled. This day ahead schedule of firming service provision would then become binding upon the selected service providers, which would be required to be online and able to provide the nominated services as scheduled. (p. 4)	
Alternative methods of payment for inertia		
ERM Power	The primary beneficiary of the dispatch of market inertia services are consumers, therefor ERM believe the most accurate way from an economic efficiency perspective to capture the value of this benefit is for cost recovery to occur from the proceeds of the settlement residue auctions currently paid to TNSPs. The benefits to consumers would include both the benefit of a lower RRP in the importing region and the increased value	As discussed in section 4.1 the Commission recognises that the majority of stakeholders did not support the use of IRSRs to fund inertia payments, however there were also alternative funding approaches for inertia payments outlined in the consultation paper which stakeholders expressed views on, namely using SRA proceeds, SRA proceeds plus additional funding from TUoS charges, or an

Stakeholder	Issue	AEMC Response
	received during the interconnector settlement reside auction process for the sale of interconnector settlement residue units that will be firmer in nature due to the dispatch of market inertia services than would otherwise be the case. If a shortfall were to occur between the cost of the market inertia services and the proceeds of the settlement residue auctions ERM support continued cost recovery from TNSPs which could result in cost recovery from future settlement residue auctions or an incremental increase in TUOS charges. ERM would not support any proposal to cap and scale back payments to market inertia service provider's post-dispatch of market inertia services as this would result in the use of a service at less than its efficient cost. Recovery of costs via the settlement residue auctions proceeds would also allow implementation of the proposed market arrangements in a timely manner as this would not significantly impact the value of already auctioned interconnector settlement residue units (p. 3)	additional charge on beneficiaries. The Commission intends to explore a range of funding options as part of its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.
Reach Solar Energy	Should a market mechanism be introduced Reach Solar Energy support the integration of inertia within FCAS markets rather than set up a new market, they also support the use of SRA proceeds plus additional funds from TNSPs to fund inertia payments. (p. 3)	
Origin Energy	Regarding the potential for an SRA hedging market to offset the loss of SRA volumes, Origin would suggest that this approach is overly complex and relies on an uncertain hedging market outcome. Origin support recovery of inertia payments from all consumers within the affected region through either a separate levy or TUOS charges. This allows the value of SRAs to be maintained which would potentially result in higher auction proceeds that could contribute towards the payment of the inertia	

Stakeholder	Issue	AEMC Response
	mechanism. (p. 1)	
Hydro Tas	Support using a similar cost recovery mechanism to that used for NSCAS. Cost recovery should be on a global basis considering the importance of supporting penetration of renewables in all regions and interconnection going forward.(p. 1)	
Australian Energy Council	AEC raises concerns around the use of IRSRs to fund inertia payments. However consider funding through SRA proceeds and additional funding from TNSPs to be an acceptable alternative. The Energy Council believes that the lack of firmness and the expected lack of liquidity in an inertia hedge market will not overcome the shortcomings in this approach, and market participants will find their risk increased without good cause. The adjunct proposal by the AEMC to auction the inertia funds, while this allays reservations about the participation of regulated entities in competitive markets, is expected to be limited in its ability to stimulate the provision of inertia hedges.(p. 1)	
Tas Networks	Recommends that the concept of additional charges be further examined. Also specific charges levied at generators not providing inertia (when compared to some typical minimum or average inertia value provided from an equivalently sized synchronous generating system) should also be considered. (p. 4)	
ENGIE	ENGIE consider that creating an inertia hedge to offset the impact of using IRSR to fund inertia payments, would likely be a complex approach and subject to various implementation issues. It is therefore unlikely to succeed and the more likely outcome will be that SRAs, which are already seen as an imperfect hedge against inter regional price risk, will see their potential use further	

<table>
<tr><th>Stakeholder</th><th>Issue</th><th>AEMC Response</th></tr>
<tr><td></td><td>limited. (p. 3)</td><td></td></tr>
<tr><td colspan="3">Addressing intra-regional constraints</td></tr>
<tr><td>Tas Networks</td><td>Consider that intra-regional constraints will grow in importance in the future. A market should be designed to be robust enough to address both inter-regional and intra-regional constraints. (p. 4)</td><td rowspan="4">As outlined in section 3.4.3 , it is not clear that additional inertia targeted at alleviating inter-regional RoCoF constraints is where the opportunities for market benefits now lie. However, as levels of inertia decline into the future, a level of inertia will be required to manage contingencies across the NEM as a whole (e.g. loss of the largest generator). Consequently, any long term review of FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS, with this potentially requiring the development of additional inertia services.

This analysis will provide a key input into establishing how inertia can be appropriately valued and integrated with existing market frameworks and alternative frequency control services such as FFR.

Addressing intra-regional constraints will be considered as part of the Commission's assessment of the appropriate design of an inertia market mechanism through the Frequency control frameworks review.</td></tr>
<tr><td>Tesla</td><td>Consider it is equally important to provide incentives for inter-regional as well as intra-regional constraints.

Tesla suggests in the design of a market mechanism it is important that the provision of inertia remains technology agnostic, and non-synchronous generators capable of delivering synthetic inertia are provided the opportunity to participate – provided they can provide the requisite service.(p. 3)</td></tr>
<tr><td>Australian Energy Council</td><td>The Energy Council suggests that intra-regional constraints should also be considered, but not at the expense of complicating the market with more granular pricing. (p. 2)</td></tr>
<tr><td>Energy Australia</td><td>The heavy emphasis on developing a mechanism that is suitable for managing constraints on Heywood limits the potential relevance of this change to the rest of the NEM. There has been very little assessment of the suitability of the proposed mechanism for other inertial shortfall issues such as intra-regional constraints. There is a risk that implementing a rule change to address a very specific issue, that is not a primary order issue, will be a distraction from developing more comprehensive solutions to inertia issues facing the NEM. (p. 1)</td></tr>
</table>

Stakeholder	Issue	AEMC Response
TNSP participation		
S&C Electric	It is likely to be far more cost effective to allow some degree of over-sizing to ensure that assets are ready to meet regional requirements. TNSPs will be restricted from earning an income from any asset delivered to meet minimum and secure operation levels of inertia, even if this might mean the asset was delivered to the customer at a lower cost. Since the minimum and secure level of inertia are required to meet islanding requirements, when the region is not an island, the assets are idle – this is an inefficient use of system assets. Or the TNSP may fund a synchronous condenser to meet other operational requirements and may provide inertial support using the same asset. The TNSP should be able to earn additional revenue from providing inertia and we are concerned that the proposed mechanism to fund the new Inertia Ancillary Service will negatively impact on TNSP revenue, particularly that redistributed to end customers. (p. 5) S&C Electric consider that if TNSPs provide service at least cost, they should be able to participate. (p. 8)	The participation of regulated entities in competitive markets can often raise concerns. These concerns can sometimes be addressed through ring-fencing the part of the business providing the competitive service from the regulated entity. However, in some cases the assets may already be funded on a regulated basis for the provision of other services. When a TNSP invests in a synchronous condenser for system strength or minimum inertia requirements, this cost is added to the business' regulatory asset base. The return that the network business earns on the asset base is recovered from customers. If a TNSP is also paid the inertia spot price for providing inertia from the same asset then it is essentially being paid twice. TNSP participation will be explored further as part of the Commission's assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.
Meridian Energy	While there are always concerns with involving regulated businesses in competitive markets, the most important test is will their involvement improve customer outcomes. The market does not exist to ensure that all market participants can participate but rather to deliver outcomes consistent with the NEO. Failure to enable TNSP participation has the potential to preclude optimum solutions being provided at least cost (p. 2)	
Origin Energy	The AEMC should explore regulations that will prevent the TNSP from receiving additional inertia revenue streams from assets that are under the RAB. Any additional inertia provided by the	

Stakeholder	Issue	AEMC Response
	TNSP will have market impacts, whether on the inertia price or the energy price between two regions. This results in market distortion and increased costs on consumers who would be doubly subsiding inertia within their region. Origin support TNSP participation in an inertia market only if assets used to provide the service are funded independently of the regulated asset base. (p. 2)	
Energy Australia	Energy Australia does not support the participation of TNSPs in an inertia market. (p. 3)	
Co-optimisation of services		
Origin Energy	Origin suggests that the early stages of the inertia market be open only to inertia providers, and that AEMO investigate the interchangeability of FFR and inertia within this market. (p. 2)	The *Frequency control frameworks review* intends to consider how best to integrate faster frequency response (FFR) services offered by new technologies into the ongoing response to frequency control.
Clean Energy Council	The CEC are concerned that the AEMC's consultation paper implies that FFR could not be a substitute for providing inertia for market benefits and that this is inconsistent with other rule changes. (p. 3)	The draft determination outlines that the *Frequency control frameworks review* intends to consider how best to integrate FFR services offered by new technologies into the ongoing response to frequency control. The potential to substitute FFR and inertia for market benefit has the potential to exist.
ENGIE	ENGIE is of the view that the binary nature of inertia provision (it is provided when a synchronous machine is on-line, and is not related to the units power output) makes co-optimisation with energy in the 5 minute NEM impracticable. (p. 3)	Any long term review of FCAS markets will need to consider how inertia provision can best be co-optimised against FCAS. However, this is likely to present technical complexities given that inertia is effectively provided on a binary basis with an entire generating unit's inertia either online or offline. Further, the speed at which inertia can be brought online reflects the start and synchronisation time of the
Tesla	Co-optimising inertial services with energy and system security services will be the most efficient market approach to incentivise inertia services in the NEM. This will both maximise the run time of existing synchronous generators as well as take advantage of	

Stakeholder	Issue	AEMC Response
	new technologies such as battery storage, and renewable generation. (p .4)	generating unit. This issue will be considered as part of the Commission's assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.
Other issues raised		
Clean Energy Council	The CEC consider that it is unacceptable that generating units with unknown RoCoF withstand capability might contribute to inertia levels to support a secure power system (p. 6)	The Commission agrees that the RoCoF withstand capability of many older generating units is the NEM is largely unknown. This will be an important consideration in the appropriate design of an inertia market mechanism.
Clean Energy Council	The CEC raise concerns that AEMO is not allowed to plan for non-credible contingencies under the rules, therefore using RoCoF constraints is outside the rules planning framework (p. 3)	The rules do not prevent AEMO from planning for all non-credible contingency events. One of AEMO's key duties, maintaining power system security, relates to credible contingency events and protected events, which are a type of non-credible contingency event (NER cl 4.3.1(a), 4.2.3(f)).
Clean Energy Council	The CEC raise concerns that the proposed market mechanism risks designing a market with a technology specific criteria such as inertia excludes other technologies from providing the service. (p. 2)	The Commission consider that the appropriate design of an inertia market mechanism will be required to be consistent with its principle of technological neutrality. An important consideration in the *Frequency control frameworks review* will be the effective co-optimisation of the provision of inertia with other frequency control services.
PIAC	PIAC highlight the potential for market power issues to arise if there is a small concentration of inertia providers in a region	The Commission acknowledges this as a potential issue and intends to explore it further in its

Stakeholder	Issue	AEMC Response
	which could raise price beyond the value to consumers. (p. 1)	assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.
Energy Australia	The use of the shadow price, where inertia is valued based on the size of the price separation when there is an interconnector constraint, could have distortionary impacts on the energy market. The inertia payments could incentivise generators in the higher priced regions to inflate their energy bids to increase the price separation difference, and therefore their inertia payment. Given this possibility, EnergyAustralia does not support the value of inertia being linked to the energy price. (p. 2)	
Tas Networks	The treatment of synchronous generators dispatched in energy market requires further consideration particularly, the justification of a separate payment for providers who provide inertia by being online anyway. (p. 3)	The Commission acknowledges that this issue should be explored further.
Energy Australia	Energy Australia consider the proposed design will not incentivise provision of inertia services due to the poor link between behaviour and payment. If generators respond to the pre-dispatch price signal there may be sufficient inertia in the market to alleviate the constraint. If the constraint does not bind, generators will not receive any payments for inertia service provision, only for energy. If these generators bid below their marginal energy cost, on the assumption that they would receive some inertia payment to cover costs, they will be dispatching at a loss. This will disincentive provision of inertia services. (p. 2)	The Commission considers that the use of appropriate constraints should be explored further. This will be an important aspect of the appropriate design of an inertia market mechanism.
Reach Solar Energy	Considers system inertia is important and will be provided by synchronous generation in the near-term, but will be increasingly provided by even faster acting asynchronous inverter technologies and/or aggregated consumer generation, controlled load shedding, installation of frequency control on Murraylink, and energy storage. Reach Solar consider the proposed market mechanism is biased to generation and suggests consumer-led	The Commission consider that the appropriate design of an inertia market mechanism will be required to be consistent with its principle of technological neutrality. An important consideration in the *Frequency control frameworks review* will be the effective co-optimisation of the provision of inertia with other frequency control

Stakeholder	Issue	AEMC Response
	offerings should feature more. (p. 3)	services.
Origin Energy	Inertia providers need a clear price signal to make commitment decisions and Origin suggests that the best way to provide this clarity is through a separate inertia price for each region. Origin envisage that this would be similar to the way an energy or FCAS price is displayed, with pre-dispatch and ST-PASA showing prices up to 7 days. Sensitivities could also be included that would capture the inertia price if additional units were to be committed. (p. 1)	The Commission acknowledges that clear market signals are required to encourage efficient investment; this principle will be applied in the assessment of the appropriate design of an inertia market mechanism.
S&C Electric	The new market for inertia services only favours incumbent large synchronous generators and is therefore undesirable. It also does not facilitate the development of a service that will deliver inertia via power electronics, which will be needed as synchronous generation leaves the system. Clarity is needed as soon as possible on what level of inertia can be provided by what type of asset. (p. 2)	The Commission consider that the appropriate design of an inertia market mechanism will be required to be consistent with its principle of technological neutrality. An important consideration in the *Frequency control frameworks review* will be the effective co-optimisation of the provision of inertia with other frequency control services.
TransGrid	The design of an effective market for ancillary services is complex, and TransGrid considers it should be considered within the context of a whole-of-NEM market review. The current focus should be on sharing existing inertia and system strength services throughout the NEM, and on ensuring that TNSPs have efficient incentives to meet the obligations placed on them. (p. 3)	The *Frequency control frameworks review* will consider this issue further.
TransGrid	In the straw man market mechanism, TransGrid notes it may not be appropriate to use NEM regional boundaries within which inertia may be required. A key issue is whether a credible contingency (or protected event style contingency) could create an inertia shortfall on the other side of a regional boundary where there is insufficient interconnection between regions, or insufficient resilience within a region. (p. 2)	The Commission intends to consider this issue as part of its assessment of the appropriate design of an inertia market mechanism through the *Frequency control frameworks review*.

C Legal requirements under the NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

C.1 Draft rule determination

In accordance with s. 99 of the NEL the Commission has made this draft rule determination in relation to the rule proposed by AGL.

The Commission has determined not to make a draft rule.

The Commission's reasons for making this draft rule determination are set out in section 2.4.

C.2 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the rule;
- the rule change request;
- submissions received with respect to consultation on the *System security market frameworks review*;
- submissions received during further round of consultation; and
- the Commission's analysis as to the ways in which the proposed rule will or is likely to, contribute to the NEO.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.[70]

70 Under s. 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a rule. The MCE is referenced in the AEMC's governing legislation and is a legally enduring body comprising the Federal, State and Territory Ministers responsible for Energy. On 1 July 2011 the MCE was amalgamated with the Ministerial Council on Mineral and Petroleum Resources. The amalgamated council is now called the COAG Energy Council.