AEMC

RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Inertia Ancillary Service Market) Rule 2017

Rule Proponent

AGL

5 September 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.

Contents

1 Introduction

The Australian Energy Market Commission's (AEMC or Commission) system security work program draws upon the work undertaken by AEMO to identify and prioritise the current and potential future challenges to maintaining system security in the national electricity market (NEM).

On 27 June 2017, the AEMC published its final report on the *System security market frameworks review*.[1] 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.

The Commission has also been assessing a number of rule change requests relating to the priority issues that were considered as part of the *System security market frameworks review*.

One of the rule change requests received from the South Australian Government and a rule change request received from AGL both relate to the management of high rates of change of frequency through the provision of inertia and frequency control services. The Commission published a draft determination on the South Australian Government's *Managing the rate of change of power system frequency* rule change request in June 2017.

The draft rule proposes to place an obligation on Transmission Network Service Providers (TNSPs) to procure the minimum levels of inertia, or alternative frequency control services, required to maintain the secure operation of the power system.

An obligation on TNSPs to provide this service will establish confidence that system security can be maintained in all regions of the NEM.

This draft rule does not provide a mechanism to realise the market benefits that could be obtained through the provision of inertia at levels above the minimum level of inertia required to maintain secure operation of the power system. The Commission considers that the ability to maintain power system security in an efficient manner would be enhanced by the development and introduction of a mechanism to obtain and pay for inertia and that this would further contribute to the national electricity objective (NEO).

AGL's rule change request concerns the introduction of a NEM *Inertia ancillary services market*. AGL proposes that such a service should reflect the value of 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".[2]

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1 AEMC, *System security market frameworks review - final report*, 27 June 2017.

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

The Commission has extended the period of time for making the draft determination with respect to the *Inertia ancillary service market* rule change request until 7 November 2017 to continue its assessment of the request with a view to implementing a mechanism to guide the provision of inertia for market benefit.

It is intended that such a mechanism will complement and build on the certainty created through to the *Managing the rate of change of power system frequency* rule change request.

This consultation paper explains the review's findings with regards to inertia, explains the interactions between this rule change request and the *Managing the rate of change of frequency* rule change request and sets out for further consultation on a number of design options associated with the introduction of a market mechanism to reward the value of inertia.

1.1 Control of power system frequency

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

In each 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.

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 rate of change of frequency 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.[3] The greater the size of the contingency event, or the lower the system inertia, the faster the frequency will change.

The Australian Energy Market Operator (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). These services are provided by generators to control system frequency in response to supply or demand disturbances. 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, a significant transmission line, or a large industrial load. 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 within the normal operating frequency bands.

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

3 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.

1.2 Rationale for 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.

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.[4]

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.[5]

The shift to newer types of generation has been more pronounced in some regions of the NEM than others. South Australia, in particular, has experienced a substantially faster change than other regions as an increasing volume of renewable energy is integrated. Flows on the interconnector with Victoria allow power system security to be maintained because of inertia provided by generators in other parts of the NEM. Where there is an outage of this interconnector, the risks to system security in South Australia increase significantly because it must rely on inertia provided by generators within the region. If there is minimal generation capacity online 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.

4 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.

5 AGL, *Inertia Ancillary Service Market*, 24 June 2016, p. 3.

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. Under the competitive procurement arrangements, AEMO would:

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

1.4 Consultation on this paper

Stakeholders are encouraged to provide feedback on this paper.

The Commission invites submissions on this consultation paper by no later than 3 October 2017.

Submissions should quote project number "ERC0208" and may be lodged online at www.aemc.gov.au or by mail to.

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1.5 Structure of this paper

The remainder of this paper is structured as follows:

- Chapter 2 sets out further detail on the role of inertia in managing system frequency and provides a description of the draft rule recently proposed by the Commission to place an obligation on transmission network service providers (TNSPs) to provide minimum required levels of inertia.
- Chapter 3 outlines the assessment approach.

- Chapter 4 sets out the design of the proposed market sourcing approach and explores some potential alternative methods of payment for inertia.
- Chapter 5 provides an assessment of the issues arising under the design options.

2 Background

This chapter sets out further detail on the role of inertia in managing system frequency and provides a description of the draft rule recently proposed by the Commission to place an obligation on TNSPs to provide minimum required levels of inertia.

2.1 Managing rapid changes in power system frequency

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.

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 rate of change of frequency (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.

There is currently no mechanism for AEMO or any other party to obtain and pay for additional inertia. In the past, inertia has been plentiful and so such a mechanism has not previously been required.

2.2 Two levels of inertia

The level of system inertia in an islanded region determines the size of the immediate RoCoF that would result when separation occurs for a given interconnector flow. Limiting the size of the RoCoF would provide:

- a higher probability of generators remaining online following the occurrence of the contingency event, limiting the risk of cascading events;
- time for emergency frequency control schemes to operate effectively; and

- time for frequency control ancillary services in the islanded system to respond and recover the frequency to normal operating levels.

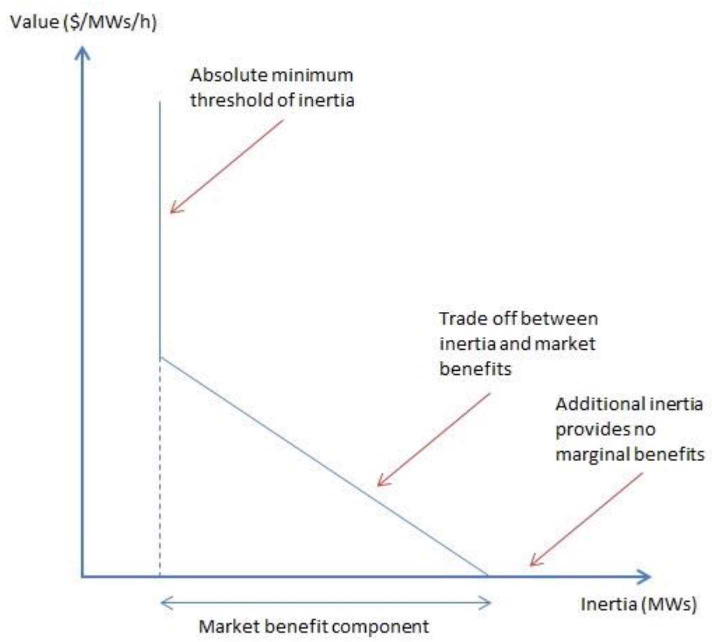
Limiting RoCoF, as described above, contributes to the system frequency remaining within the bounds of the Frequency Operating Standards (FOS):

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. Operating at this minimum level may require load shedding but would be sufficient to maintain the islanded system in a satisfactory operating state and 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 2.1, which shows a theoretical demand curve for inertia.

Figure 2.1 Value of inertia and the amount of inertia provided

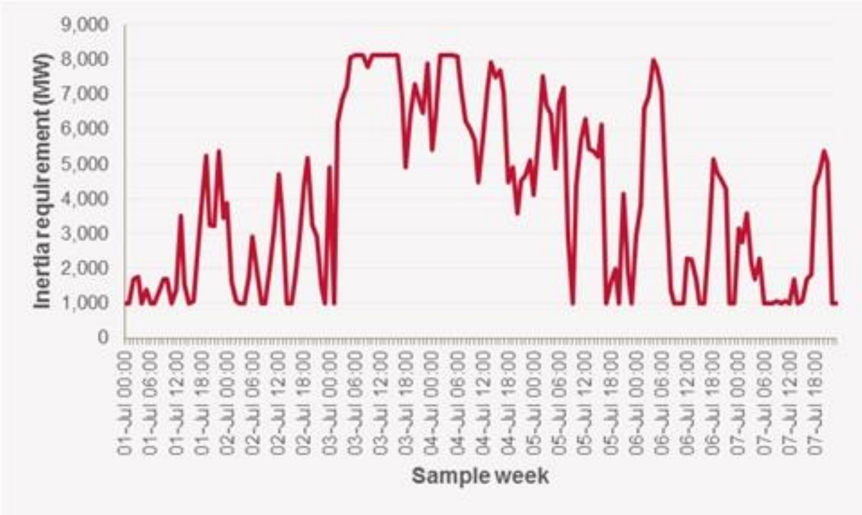


The vertical line on the left represents the minimum level of inertia that is required to maintain the islanded system in a satisfactory operating state. This vertical line is a lower bound on the level of inertia that could feasibly be required in order to operate the system within the FOS and maintain 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 fast frequency response (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 2.1 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.

Figure 2.2 shows how inertia requirements can vary over time depending on the prevailing system and network conditions.

Figure 2.2 Potential variability in required inertia in South Australia



Minimum required levels of inertia

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

1. The satisfactory operating level of inertia - the minimum threshold level of inertia required in order to operate the system within the FOS and 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 National Electricity Rules (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 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:

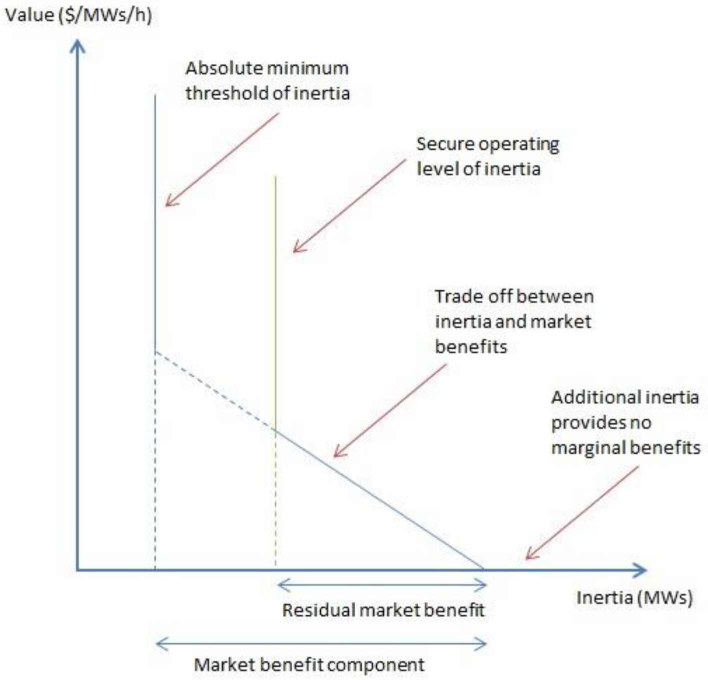
1. *Availability and capability of contingency FCAS* - The capabilities and expected response times of contingency FCAS in the islanded region would determine the maximum RoCoF that could be managed without the frequency moving outside the bounds of the FOS. Inertia does not act to arrest the frequency 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 2.3 shows the secure operating level of inertia in relation to the minimum system threshold level of inertia.

Figure 2.3 The minimum threshold level and the secure operating level



Additional inertia for market benefit

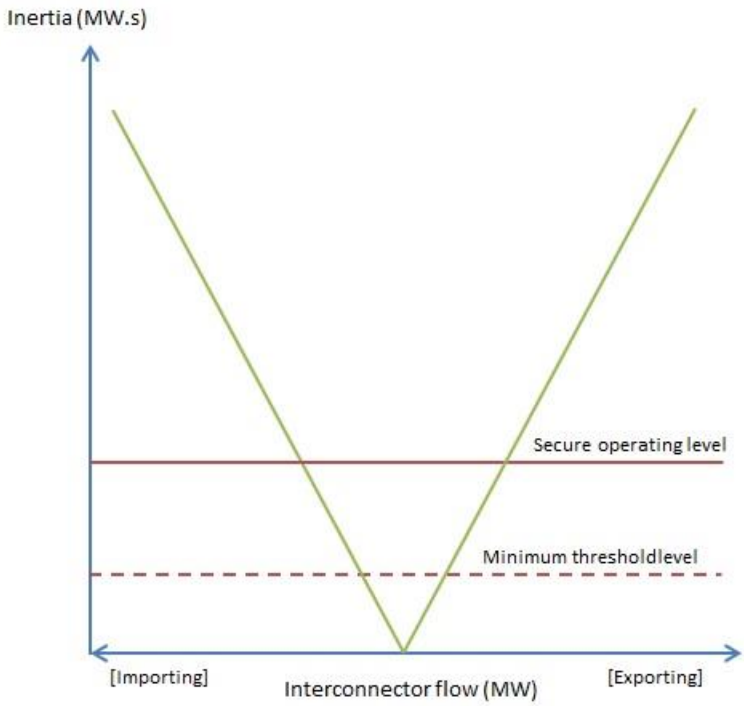
When operating as an island, the secure operating level of inertia is only sufficient to operate the islanded system under specific highly constrained conditions.[6] However a higher level of inertia may provide market benefits by either:

- 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.

Figure 2.4 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.

6 This discussion is based on a region that has the potential to be separated from adjacent regions as a single contingency.

Figure 2.4 Comparison of minimum required levels of inertia and additional inertia for market benefit



On 27 June 2017, the AEMC made a draft rule to place an obligation on TNSPs to make available the required minimum levels of inertia[7]. This draft rule does not provide a mechanism to realise the market benefits that could be obtained through the provision of inertia above the minimum obligation on TNSPs. However, as noted in the final report on the *System security market frameworks review*, the Commission considers that the ability to maintain power system security in an efficient manner would be enhanced by the development and introduction of a mechanism to obtain and pay for this additional inertia. The Commission intends to pursue the development of such a mechanism to complement the TNSP obligation imposed through this rule change request. The potential design of this mechanism is the subject of this consultation paper and a further discussion is set out in subsequent chapters.

2.3 Draft rule to provide minimum required levels of inertia

On 27 June 2017, the Commission published a draft rule to place an obligation on TNSPs to make available the required minimum levels of inertia. The advantages of TNSP provision include:

- the certainty of availability of the required minimum levels of inertia that would result by TNSPs procuring inertia through network support agreements or themselves providing the required level of inertia through synchronous condensers;

7 The required minimum levels of inertia refer to the minimum threshold level of inertia and the secure operating level of inertia.

- the financial incentives that TNSPs have under network regulation frameworks to minimise the costs associated with their obligations;
- consistency with the principle that TNSPs are accountable for outcomes of their networks;
- the ability to coordinate inertia provision with the more locational requirements of maintaining system strength, a role that the Commission is also recommending reside with network service providers.

A key consideration for the Commission in developing the mechanism set out in the draft rule has been to define what constitutes the minimum required level of inertia. The approach adopted has been to focus on the risks associated with the possible separation of areas of the network into desynchronised islands. Even if the power system is operated in a heavily constrained manner, there will still be a requirement for some level of inertia to be provided if separation is a credible contingency or protected event so that a resulting island could feasibly be operated post-event. The draft rule consequently places obligations on TNSPs in regard to "sub-networks", which are areas of the power system susceptible to islanding, and which could otherwise be operated in an islanded state.

Further details can be found in the draft determination document but, in summary, the main features of the draft rule are:

- An obligation on AEMO to determine sub-networks in the NEM that are required to be able to operate independently as an island.
- AEMO to determine, through a prescribed process, the minimum required levels of inertia for each sub-network 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 TNSPs to make continuously available the minimum required levels of inertia.
- An ability for TNSPs to contract with third-party providers of alternative frequency control services, including FFR services, as a means of meeting a proportion of the obligation to provide 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 (i.e. instruct them to provide inertia) under specific circumstances in order to maintain the power system in a secure operating state.

The final determination on this rule change request is currently scheduled to be made on 19 September 2017.

3 Assessment Framework

3.1 Rule making test

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).[8] This is the decision making framework that the Commission must apply. The NEO is:[9]

> " 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."

Based on its assessment of the issues raised in this rule change request, the Commission considers that the relevant aspects of the NEO are the efficient investment in and operation of electricity services with respect to the price of supply of electricity and the safety and security of the national electricity system.

3.2 Assessment Framework

The Commission proposes to use the following principles to assess whether the proposed rule change request promotes the NEO:

- **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.

8 Section 88 of the NEL.

9 Section 7 of the NEL.

- **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.[10] 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. 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.

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

4 Options to procure inertia for market benefit

Over the course of the System Security Market Frameworks Review, the Commission considered two broad approaches for the design of a mechanism to provide additional inertia for market benefit:

1. An incentive scheme designed to reward TNSPs for the delivery of additional inertia that allows for greater power transfer capability on the network.

2. A market sourcing approach designed to reward all providers of inertia by making use of the inter-regional settlement residues (IRSR) that accrue on interconnectors.

In relation to the TNSP incentive scheme, the Commission considered that the identification of market benefits would fit well with the TNSP planning frameworks, and it would be possible to place financial incentives on TNSPs to drive efficient levels of provision. However, a further key consideration was the potentially significant variability in inertia requirements. Figure 2.2 above provides an illustration of this, showing that the amount of inertia required to prevent a RoCoF constraint on an interconnector from binding can vary by a factor of eight, and over a very short period of time.

In order to manage this variability in inertia requirements, the Commission considered two broad approaches to the design of a TNSP incentive scheme being based on an operational incentive to meet a targeted level of inertia (or a proportion of the time when RoCoF constraints should not bind) or, alternatively, by rewarding TNSPs based on actual market outcomes.

However, the Commission concluded that both options would likely be problematic. A target based approach would require the body setting the target to be able to accurately forecast both the likely costs of inertia provision and the resulting benefits. To quantify the benefits would require an ability to accurately forecast market outcomes over the long term.

An incentive scheme based on actual market outcomes could produce more efficient outcomes by avoiding the above forecasting issues, and incentivising TNSPs to provide additional inertia at times when it was most valued. The aim of the scheme would be to get TNSPs to manage the trade-off between the value of inertia and the cost of providing it. The value of inertia would be given by its shadow price, as described in Box 4.1.

Box 4.1 A shadow price for inertia

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 the value of the next unit of electricity available to be supplied to that region for that dispatch interval. It is the marginal cost of the constraint that supply must equal demand.

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

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[Hz] x Heywood Flow [MW])/(RoCoF [Hz per second])≤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, ie the value of inertia relates to the difference in the regional reference prices between South Australia and Victoria.

However, the success of a market outcomes-based scheme would be reliant on TNSPs making real time decisions about committing generation and scheduling inertia to alleviate constraints, a role they have not previously engaged in. It is far from clear that TNSPs would be qualified to undertake this task, or that having them do so would be desirable. A further discussion of these issues is contained in the AEMC's final report on the *System security market frameworks review*.[11]

In light of the issues identified with TNSP provision of inertia for market benefits, the Commission considers that a market-based mechanism is likely to be more appropriate to deliver the market benefit aspect of inertia, and would have significant advantages in that wholesale market participants, rather than TNSPs, would continue to make generator commitment decisions.

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. In this way, competitive market mechanisms are always the Commission's preferred approach. And, in this case, many of the concerns regarding the use of a market sourcing approach for procuring a minimum level of inertia are less of an issue when seeking to realise market benefits.

In particular, while it would be important for AEMO to enable inertia to maintain system security, this level of certainty is less important for market benefits. In the presence of a market price for inertia, inertia providers would have an incentive to

11 AEMC, *System security market frameworks review - final report*, 27 June 2017, pp. 48-53.

self-commit at times when inertia was valued. Similarly, while the certainty provided by TNSP contracting is crucial to underpinning investment in minimum levels of inertia to maintain system security, this certainty would be less critical where the objective is to realise additional market benefits.[12]

A market based mechanism offers a transparent approach that would facilitate competition in the provision of inertia. By taking inertia prices into account in their energy market offers and commitment decisions, participants would effectively co-optimise inertia provision with the energy market. Increases in the expected inertia price would incentivise greater provision, and this market signal - which would be provided to all market participants - should allow the costs and benefits of inertia provision to be efficiently balanced.

4.1 Market sourcing approach

In light of the above considerations, in the final report for the *System security market frameworks review* the Commission presented a straw man design for a market-based mechanism to reflect the value of inertia.[13] 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 IRSRs that accrue on interconnectors.

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.

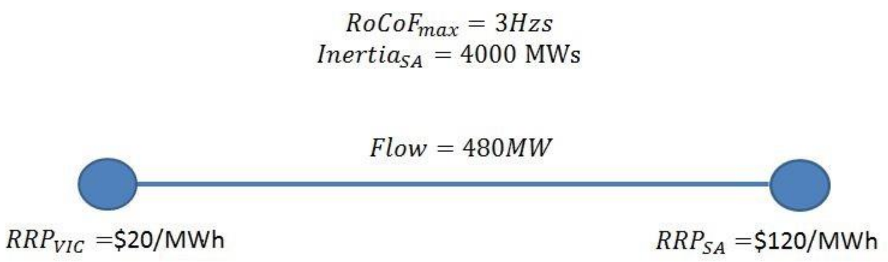
12 Although, as described in chapter 4, the Commission has identified a market mechanism where there would be some incentive for some market participants to contract with inertia providers.

13 AEMC, *System security market frameworks review - final report*, 27 June 2017, pp. 53-4.

Where an inter-regional RoCoF constraint binds, the IRSR is equal to the shadow price of inertia (as discussed in box 3.1) 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 ("K") 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 proposed 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.

Question 1

Do you consider a market sourcing approach to be preferable to a TNSP incentive scheme for providing inertia? If so, do you consider the use of IRSR funds accruing as a result of RoCoF constraints to be an appropriate mechanism for funding inertia payments?

4.2 Alternative methods of payment for inertia

The Commission has come to a view that a market-based mechanism would have significant advantages in that wholesale market participants would continue to make generator commitment decisions. By taking inertia prices into account in their energy market offers, participants would effectively co-optimise inertia provision with the energy (and FCAS) market.

A market-based mechanism would offer an open and transparent approach that would best facilitate competition in the provision of inertia. It would also be flexible in that it would allow the level of the service to vary over time to adapt to changing market conditions. Increases in the expected inertia price would incentivise greater provision, and this market signal, which would be provided to all market participants, should allow the costs and benefits of inertia provision to be efficiently balanced. Further, while implementation would not be trivial, much of the framework for pricing and settlement is already in place.

However, 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 explored further in chapter 5 but are summarised as follows.

- By transferring some IRSR funds away from SRA units holders, the proposed 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 proposed approach.
- The proposed 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 proposed funding approach using IRSRs would not address intra-regional RoCoF constraints or other types of constraints which are applied to manage system security.

In the light of these considerations, the Commission is consulting on alternative approaches to funding inertia payments under the proposed market mechanism.

The alternative approaches are as follows:

- Using the proceeds from the settlements residue auctions (SRAs) rather than the IRSR funds themselves to fund inertia payments.
- Using the proceeds from the SRAs and recovering any additional required funds from TNSPs.
- Levying a new charge to recover the funds, for instance on consumers and/or generators.

4.2.1 Using SRA proceeds

Price separation between regions of the NEM creates risk for parties that contract across those regions. This risk is equal to the price difference between the regions multiplied by the volume of the contract.

To offer participants an opportunity to manage this risk, AEMO auctions the rights to the IRSRs, which represent the price difference multiplied by the total flow between the regions. In these settlement residue auctions, SRA units, representing a right to a certain portion of the IRSR, are offered to auction participants. Once the auction is completed, the settlements residue is distributed among successful auction participants proportionally to the number of units they have purchased.[14]

Rather than using the IRSRs themselves to fund inertia payments, an alternative option would be to use the SRA auction proceeds. Inertia prices would continue to be derived from the shadow price, as described earlier.

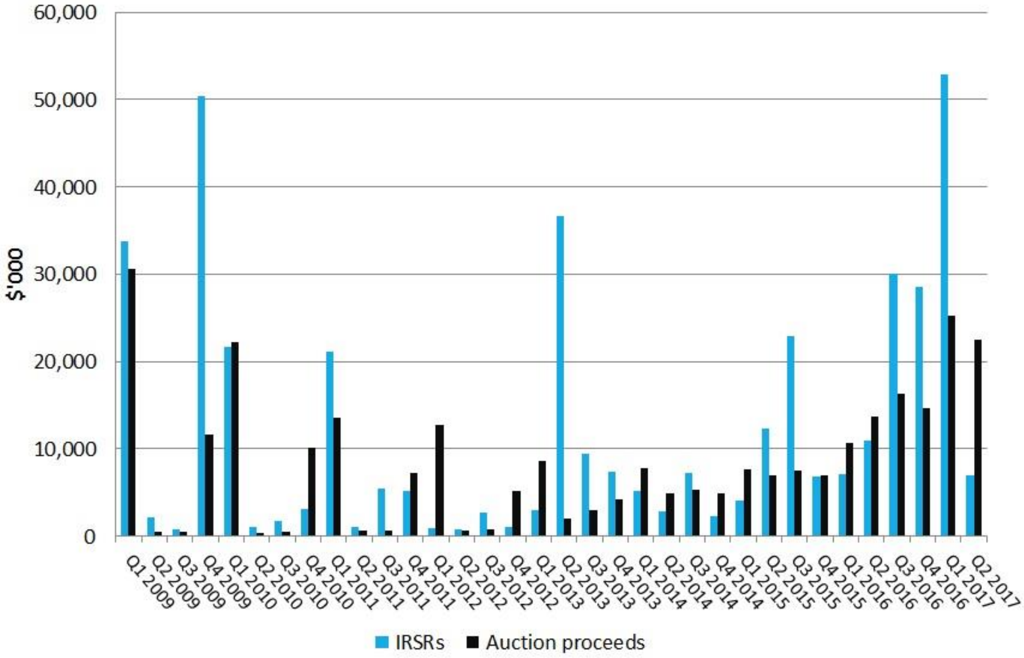
There may therefore be times when the SRA auction proceeds are insufficient to fund the calculated inertia payments. Under this option, in such circumstances inertia payments would be scaled back on a pro-rated basis to match the amount of the funds available.

AEMO forwards the auction proceeds to the TNSPs located in the importing regions. Those TNSPs then pass these proceeds to consumers in the form of discounted transmission use of system (TUoS) charges. Under this alternative option, payments to TNSPs would reduce, which would consequently reduce the extent to which TUoS charges are discounted.

Figure 4.1 shows the IRSRs which accrued in the Victoria to South Australia direction for each quarter going back to the beginning of 2009. Typically, the IRSR funds accruing on the interconnector have been larger than the corresponding auction proceeds. In the instances where the proceeds have exceeded the size of the IRSRs, the difference has tended to be small.

14 One SRA unit represents a nominal MW of capacity and would provide a firm hedge if flows in MW on the relevant interconnector were equal to the number of units auctioned. However, the firmness of a SRA hedge is often uncertain and volatile as flows can be constrained below this level, due to factors such as intra-regional generator bidding behaviour and network outages.

Figure 4.1 Comparison of IRSR funds and auction proceeds - Victoria to South Australia[15]



4.2.2 Using SRA proceeds and recovering any additional funds from TNSPs

In the first option (set out above) inertia payments would be capped by the SRA proceeds available. Under this second option, this capping would be removed.

Instead, to the extent that total inertia payments over a given period exceeded total SRA proceeds over the same period, the additional funds would be recovered from TNSPs. The existing payments made to TNSPs would be permitted to be negative, with the consequence that TUoS charges would be increased rather than reduced.

A similar mechanism already exists whereby AEMO recovers the costs of negative IRSRs from TNSPs, which recover these costs from market customers through TUoS charges.[16] However, negative IRSRs are essentially capped, albeit to a non-zero level, as described in Box 4.2 below.

Box 4.2 Negative IRSRs

Inter-regional settlements residue can be positive or negative. Negative inter-regional settlements residues arise when counter-price flows occur. Counter-price flows occur when electricity flows from the higher priced region to the lower priced one.

15 https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Settlements-and-payments/Settlements/Settlements-Residue-Auction/Reports

16 Clause 3.6.5(a)(4) of the NER.

There are several reasons why this can occur, including issues with, and errors in, the dispatch process, metering issues, bidding behaviour of scheduled generators, operation of particular transmission constraint equations, misalignment between five minute dispatch and 30 minute settlement periods, and non-compliance with dispatch targets.

Counter-price flows can also occur as a result of an intra-regional constraint being present. The dispatch of generation in the NEM is based on generators' offer prices, which represent the lowest price at which they are willing to be dispatched. The National Electricity Market Dispatch Engine (NEMDE) seeks to minimise total dispatch costs (as represented by the price offers) while ensuring that:

- sufficient generation is dispatched to meet the load in total
- any capacity limitations in the transmission network are not exceeded

During the process of dispatch optimisation, the lowest cost result according to the objective function of NEMDE in the presence of constraints can result in counter-price flows between regions.

Such counter-price flows result in the accrual of negative IRSRs as the amount of energy flowing between the regions is multiplied by a negative price difference between the exporting region and the importing region. Negative settlements as a result of a higher price region exporting to a lower price region increase TUOS charges in lower priced regions, because the importing TNSP is responsible for covering any negative settlements residue arising from the counter-price flows.

In the example below, there is a constraint[17] between RRN in South Australia (SA) and the generator in South East South Australia (SESA). The generator in SESA has the lowest offer price, and is dispatched by NEMDE on that basis. However, the location of the constraint within SA means that not all the electricity generated in SESA can reach the demand centre at the RRN, and instead some is exported and consumed in Victoria.

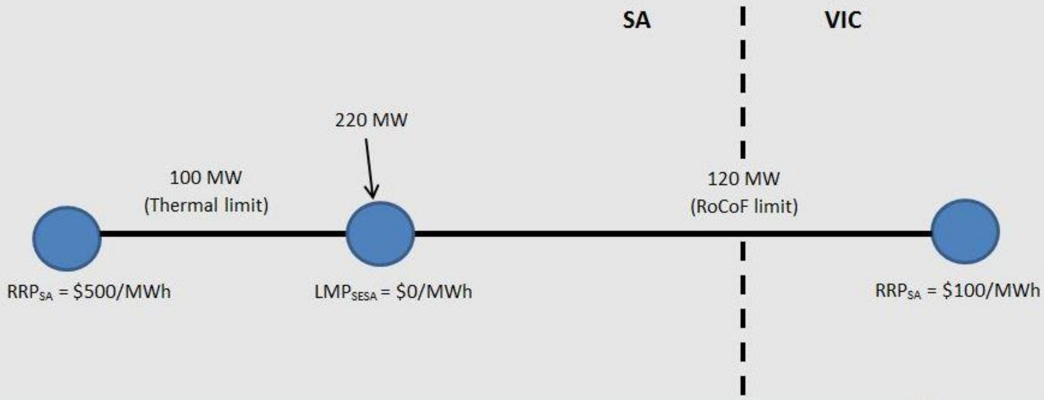
To ensure demand is met in SA, it is necessary to dispatch the higher priced generator in SA which sets the RRP in SA at $500/MWh. As the generator in SESA is also located in the same region it is also paid $500/MWh. However, consumers in Victoria will only pay the RRP of $100/MWh including for the 120MW of imported SESA generation. This will result in a negative IRSR of $48,000 per hour; which when added to the inertia payment of $12,000 (also paid by the IRSR) results in increasing the negative IRSR to $60,000 per hour.

17 This example is illustrative only. Historically a binding RoCoF constraint has never occurred during a counterprice flow. Counterprice flows have occurred due to thermal or stability constraints.

$$RoCoF_{max} = 3Hzs$$

$$Inertia_{SA} = 1000\text{MWs}$$

$$RoCoF\ limit = 120\text{MW}$$



$$Inertia\ Price = (\$100 - \$0) * \frac{3}{25} = \$12MWs/h$$

$$Inertia\ Payment = 1000MWs * \$12MWs/h\ = \$12{,}000$$

$$IRSR\ = 120MW * (\$100 - \$500)\ =\ -\$48{,}000$$

$$IRSR\ deficit\ = \$48{,}000 + \$12{,}000 = \$60{,}000$$

When the value of negative IRSRs reaches or is expected to reach $100,000, AEMO intervenes to manage negative IRSRs by 'clamping' or, in other words, invoking constraint equations over a directional interconnector, to reduce counter-price flows and hence limit the further accumulation of negative IRSRs. These constraint equations remain in place until AEMO decides that the constraint equations can be revoked because the conditions causing the counter-price flows no longer persist.

4.2.3 An additional charge

A third option would retain the mechanism whereby inertia prices are derived from their shadow price however the cost of the inertia payments would be recovered directly from generators or consumers through an additional charge.

Similar arrangements are currently used by AEMO for the recovery of costs for contingency FCAS. As contingency lower FCAS is used to control frequency in response to major variations caused by contingency events such as the loss of the largest load or a transmission element on the system, all payments for these services are recovered from customers. Contingency raise requirements are set to manage the loss of a generator on the system therefore payments are recovered from generators

This option would involve broadly consistent treatment of cost recovery for inertia and contingency FCAS. For the purpose of FCAS payments and recovery, the market is treated globally. Hence, for the purpose of recovery, participants are treated equally, regardless of region. In the case of inertia requirements the beneficiaries are likely to be region specific, therefore recovery of inertia payments from consumers in the benefiting region would seem appropriate.

Generators exporting energy to regions where an inertia shortfall is present are also likely to benefit from a reduction in congestion on interconnectors and increased flow, therefore it may also be appropriate for a portion of inertia payments to be recovered from benefiting generators.

Question 2

Do you consider any of these alternative methods of payment for inertia to be preferable to the proposed IRSR funding approach? Are there any alternative funding arrangements that are not discussed, which you would consider to be preferable?

5 Assessment of the potential approaches

There are a number of reasons which may limit the effectiveness and efficiency of using the IRSR to fund inertia payments in a market sourcing approach and which may justify the adoption of an alternative funding approach. These reasons are explored further in this chapter and include:

- reduced effectiveness of SRA units as a means of hedging inter-regional spot price risk
- a limited ability to address intra-regional RoCoF constraints or other types of constraints formulated for system security purposes.

There are also a number of additional considerations to be taken into account including:

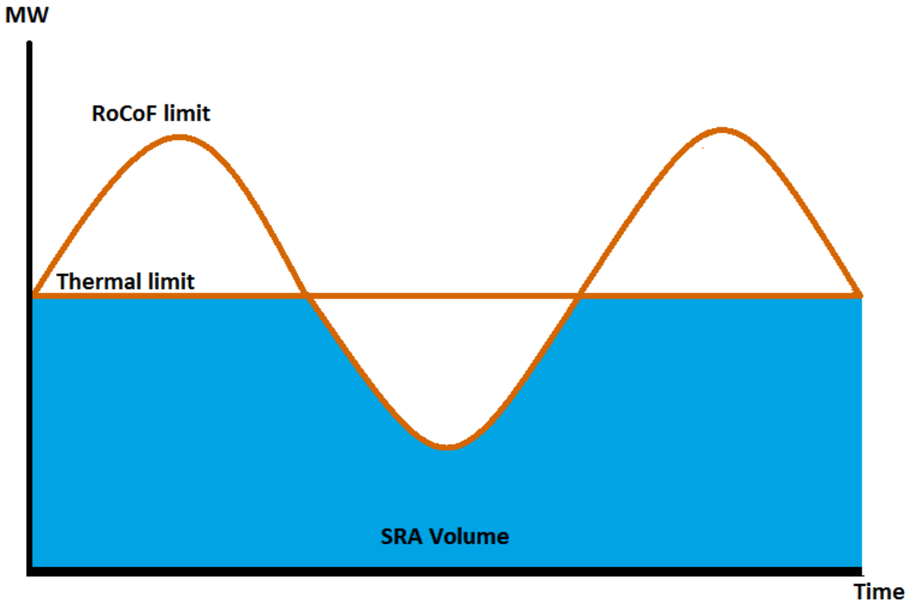
- TNSP provision of inertia services within a competitive market environment
- a lack of co-optimisation of inertia with energy and FCAS through the NEM dispatch process.

5.1 Impacts on SRAs and inter-regional hedging

A key issue would be the impact of using the IRSR funds on the existing settlements residue auctions. By using the IRSRs in this way when RoCoF constraints bound, a "gap" would be created in the value of SRA units and potentially degrade the effectiveness of these, to the extent that they are currently used to hedge against inter-regional price risk.

The impact of RoCoF constraints on SRA units is illustrated in Figure 5.1. Whenever the thermal constraint binds, the MW volume under SRA units is the same but whenever the RoCoF constraint binds, the MW volume under SRA units is reduced.

Figure 5.1 Application of RoCoF constraints on SRA unit volume

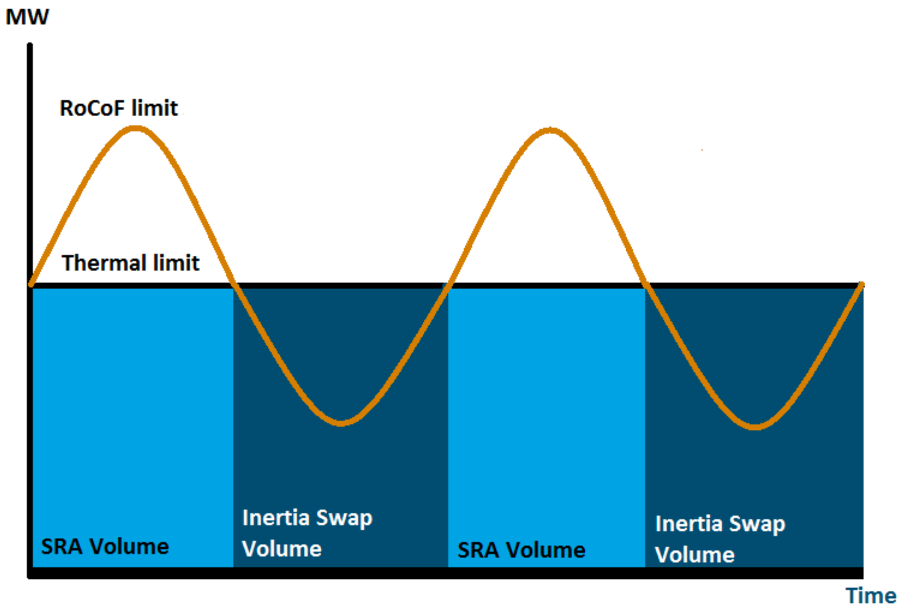


The impact of using IRSRs to fund inertia payments whenever a RoCoF constraint binds results in a reduction in the value of SRA units (the light blue section in Figure 5.2). This is because IRSR funds are diverted from the holders of SRA units to the providers of inertia.

The Commission notes that one option for protecting against this could be for purchasers of SRA units to also enter into contracts with recipients of inertia payments: an "inertia hedge". By entering into the two instruments, purchasers would receive a stream of payments from the SRA units when non-RoCoF constraints bound and from the inertia hedge when RoCoF constraints bound.

This is illustrated in Figure 5.2. Whenever the RoCoF constraint binds, the inertia provider receives IRSR funds which it pays out to its counterparty under the inertia hedge in exchange for a fixed inertia price. In any other circumstance where the thermal constraint binds, the IRSR funds would accrue to holders of the SRA units as usual.

Figure 5.2 Use of an inertia hedge to manage the RoCoF constraint



The forward price revealed in the sale of inertia hedges by inertia providers could also act as a valuable signal to guide investments in inertia over the long term. While a market mechanism such as this would be more flexible, a principal concern is that it might equally provide less certainty. The presence of a market price for inertia would offer inertia providers an incentive to self-dispatch at times when inertia was valued but there would be no certainty over either dispatch in the short term or investment in the longer term.

Without a liquid secondary contract market for inertia, the incorporation of inertia services into the existing wholesale energy spot market framework is unlikely to provide the necessary levels of certainty to prospective investors. To the extent that secondary trading in inertia hedges was established, this could address concerns that a spot price for inertia by itself would give insufficient certainty to underpin investment.

Question 3

To what extent would the proposed IRSR funding approach diminish the effectiveness of SRAs as an inter-regional hedge? Do you agree that inertia hedges could be used to assist with inter-regional hedging and would this provide increased certainty to providers of inertia?

5.2 Addressing intra-regional RoCoF constraints

As discussed previously, the Commission understands that, in the near term, RoCoF constraints are most likely to be applied on an inter-regional basis, and that, by restricting power flows between regions, these constraints are likely to have a significant economic impact.

Inertia spot payments to inertia providers would occur when an inter-regional RoCoF constraint binds. The positive inertia price would act as a signal to provide additional inertia where the proceeds from the spot payments are expected to exceed the costs of doing so.

As such, a mechanism using IRSR funds to pay inertia providers would only work for contingencies involving inter-regional separation. It would not provide a direct source of funding for RoCoF constraints associated with intra-regional separation or other types of constraints, such as those associated with transient stability.

Increasing the level of inertia to alleviate an inter-regional RoCoF constraint may also have effects on alleviating intra-regional RoCoF constraints or transient stability constraints. However, any consequential alleviation of these constraints would only occur by virtue of the inertia provided to alleviate the inter-regional constraint. There would be no specific price signal provided to address any other constraints besides the inter-regional RoCoF constraint.

IRSR payments are made to all inertia providers within the region irrespective of their precise location and consequential impact on alleviating other constraints. Initially, the alleviation of inter-regional RoCoF constraints is likely to have the greatest economic benefits and the precise location of inertia within the region will not be relevant as long as that location remains synchronously connected to the rest of the regional network.

However, valuing inertia through IRSR payments sends only a very broad locational price signal to intending inertia providers. Over time, locational signals are likely to become more important as synchronous generators retire and new potential sources of inertia are introduced. Without a satisfactory locational signal, areas within NEM regions may increasingly arise which, due to a lack of inertia, are unable to maintain stable operation under certain operating conditions. This could especially be an issue if these areas are at risk of separation from the rest of the NEM and there is a requirement or expectation that these areas are able to maintain operation as an islanded system. A potential example of this could be the separation of Northern Queensland from Southern Queensland.

Secure operation of these areas of the network may require the application of intra-regional RoCoF constraints to manage sudden changes in frequency should separation occur. The provision of additional inertia will have value in alleviating these constraints.

To the extent that such risks become a material issue, a separate mechanism would be required to procure inertia on a sub-regional basis to efficiently respond to any intra-regional RoCoF constraints. This would equally apply to other types of constraints which can be alleviated through the provision of additional inertia.

A potential future mechanism would therefore need to value each synchronous unit's contribution to alleviating a range of different constraints through a much more granular approach to pricing, such as generator-specific pricing.

Question 4

To what extent do you see there to be a need to address inter-regional RoCoF constraints versus intra-regional RoCoF constraints or other types of constraints?

5.3 TNSP participation

Another issue for further consideration is the participation of TNSPs in the market mechanism. To the extent that TNSPs provide inertia, for instance through the operation of synchronous condensers, this would result in funds accruing in settlement, raising the question as to whether these funds should be distributed to the TNSPs.

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 this case the assets may already be funded on a regulated basis (for instance, to provide system strength or meet the minimum inertia requirement).

When a TNSP invests in a synchronous condensor 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.

The shared asset guidelines set out the Australian Energy Regulator's (AER) approach to sharing the benefits with consumers of network assets that provide both regulated and unregulated services. The AER may reduce the annual revenue requirement for service providers to reflect the costs attributable to services generating unregulated revenues.

However, operation of the shared asset guideline may not be appropriate in this case as the AER will take action when the unregulated revenues from shared assets are more than 1 per cent of a service provider’s total annual revenue and then reduce a service provider's regulated revenues by around 10% of the value of unregulated revenues earned from shared assets. This may not be an accurate reflection of the value of inertia and therefore the full benefit of additional inertia for consumers may not be realised.

A practical solution may be to treat these assets in exactly the same manner as other TNSP assets facilitating inter-regional power flows. These assets are currently funded on a purely regulated basis and the funds they attract in settlement - the IRSRs - are auctioned off to participants. The proceeds of the auction process are then distributed to the TNSPs which flow back to consumers in the form of reduced TUoS charges. AEMO could also auction inertia payments accruing to TNSPs in the same way as it currently auctions IRSRs – creating another form of an "inertia hedge".

Alternatively, TNSPs could return these funds to consumers directly through reduced TUoS charges. However the benefits of creating an auction process for these funds is that it creates an opportunity for participants to manage the risk of varying price separation between regions.

The Commission recently published a draft rule determination around the secondary trading of SRAs.[18] It is envisaged that if a decision to implement secondary trading is made, this should allow units to be traded more easily which is likely to bear greater value for market participants, resulting in higher auction proceeds. Increased auction proceeds, all else being equal, should reduce the TUoS charges to be collected from the TNSPs' customers. If AEMO auctioned off inertia funds in the same manner as SRAs and a secondary market were to emerge, similar benefits could be realised.

AEMO auctioning off inertia funds should mitigate concerns associated with the participation by regulated entities in a competitive market and also readily allow purchasers of SRA units access to a source of inertia hedges. However, it should be noted that the inertia payments accruing to TNSPs might represent only a relatively small proportion of the inertia market, with the majority being earned by synchronous generators.

A challenge with the option is around ensuring this type of inertia hedge is valuable. The buyer of an inertia hedge would have to be guaranteed that the TNSP would act on price signals and provide inertia when it is valuable.

As the TNSP is not earning any direct revenue there would be no incentive to run based on a price signal alone. The TNSP has no basis upon which to determine the provision of inertia in real time.

A possible solution would be to introduce an incentive scheme where the TNSP would be provided with a reward if inertia is provided when it is most valuable to the market. The scheme could be designed similar to the Service Target Performance Incentive Scheme (STPIS), based on a target level and place a portion of the TNSP's revenue 'at risk', depending on its performance.

Given that the target would be assumed to represent the optimal level (as best it could be calculated), TNSPs should not be rewarded for exceeding the target as this would represent an over-provision of inertia. Rather, performance should be measured based on deviation from the target. While this would tend to imply a scheme based around penalties only, a TNSP could potentially be rewarded if it out-performed some "breakeven point" (e.g. if the TNSP was only two per percentage points away from the target and the breakeven point was five percentage points, it would earn a reward).

Any such incentive scheme would most likely be funded by consumers. Therefore, it is essential that the overall value associated with the proceeds from auctioning the funds outweigh the cost of the scheme for consumers.

18 AEMC, *Secondary trading of settlement residue distribution units – draft determination*, 18 July 2017.

Question 5

What do you see as the main concerns with TNSP participation in a market sourcing approach? How can these issues be resolved?

5.4 Co-optimisation of inertia with FCAS and energy

The payment of IRSR funds to inertia providers is predominantly targeted at addressing the risk associated with regional separation, as this is where the immediate issues currently lie. By funding inertia payments from IRSRs, the market sourcing approach is based on the interconnector being the largest contingency. However, as levels of inertia decline into the future, there may become a point where the level of inertia required to manage contingencies across the NEM as a whole will need to be considered. There may be instances where the application of RoCoF constraints are driven by the loss of single large generating units.

Currently, AEMO procures FCAS to control frequency in response to major variations caused by contingency events, including the loss of large generating units. The inherent value of inertia as a means of limiting frequency changes suggests that, going forward, FCAS and energy may increasingly need to be optimised against the presence of inertia in each dispatch interval.

The proposed market sourcing approach does not optimise the level of inertia with energy or FCAS through the dispatch process. Instead, market participants take expected inertia payments into account in structuring their energy market offers. Generators dispatched in the energy market who are providing inertia would receive inertia payments in addition to energy market payments.

In order to properly co-optimise inertia with energy and FCAS, decisions on the level of inertia to be provided in any dispatch interval would need to be incorporated into the dispatch process.

The physical characteristics of the supply of inertia may present a number of issues which may inhibit the effective integration of inertia into the existing wholesale energy market dispatch process. For any five-minute dispatch interval, the level of inertia in the system is currently dependent on the combination of synchronous generators that are online at the time. Generators provide all of their inertia when they are online or no inertia when they are offline, regardless of energy output. Therefore, any increase in the level of inertia would require the start-up of an additional generating unit.

This is different to energy where an incremental increase in the demand for energy can generally be accommodated by an incremental increase in the output of the generating units that are already online. As such, the provision of inertia through a five-minute dispatch model may require generators to be notified well in advance of the relevant dispatch interval, such as through a day-ahead dispatch model. The relative inflexibility of existing thermal generating plant in terms of start times suggests that care will need to be taken in any such market design in order to minimise the ability of generators providing inertia to influence energy price outcomes.

The effective co-optimisation of inertia with FCAS will become increasingly important as new faster forms of FCAS are developed and introduced to the market. Issues associated with integrating the provision of inertia into the wholesale energy dispatch process are unlikely to apply to the provision of fast frequency response (FFR). FFR would not face the same unit commitment times as synchronous generating units that provide inertia. As such, FFR services are likely to be able to be co-optimised with the provision of energy through the existing energy market dispatch process, similar to the existing markets for FCAS.

Nevertheless, it is not yet clear how any new markets for FFR should be designed and how these markets would be co-optimised with inertia services in the long-term. In designing FFR markets, it may be desirable to reconsider the rationale for the FCAS markets that currently exist.

There are six contingency FCAS markets in the NEM designed to manage frequency control after a system disturbance. An increasingly important question is whether those markets remain relevant in terms of meeting the emerging needs of frequency control in the NEM.

A key issue raised by stakeholders relates to the charging arrangements associated with existing services, with some concerns being raised that current charges for contingency FCAS do not provide efficient price signals. Further, any long term review of FCAS markets will need to take into account the consistent treatment of cost recovery arrangements with inertia services.

As discussed in Section 2.2, the proposed IRSR funding approach for inertia is predominantly targeted at addressing the risk associated with network separation and charges the interconnector for the provision of inertia. This is inconsistent with the current arrangements for contingency FCAS where the costs are instead charged to market participants in the importing region. Ideally, a consistent method of cost recovery would be applied across the different services such that the price paid by the users of the services reflects the marginal value that those users place in the service.

The development of new FCAS markets is likely to be complex and time consuming. The Commission intends to undertake this comprehensive review of the structure of existing FCAS markets and potential longer term co-optimisation with inertia services as part of the *Frequency control frameworks review*.

Question 6

To what extent do you see it as desirable to co-optimise inertia with energy and FCAS through the NEM dispatch process?

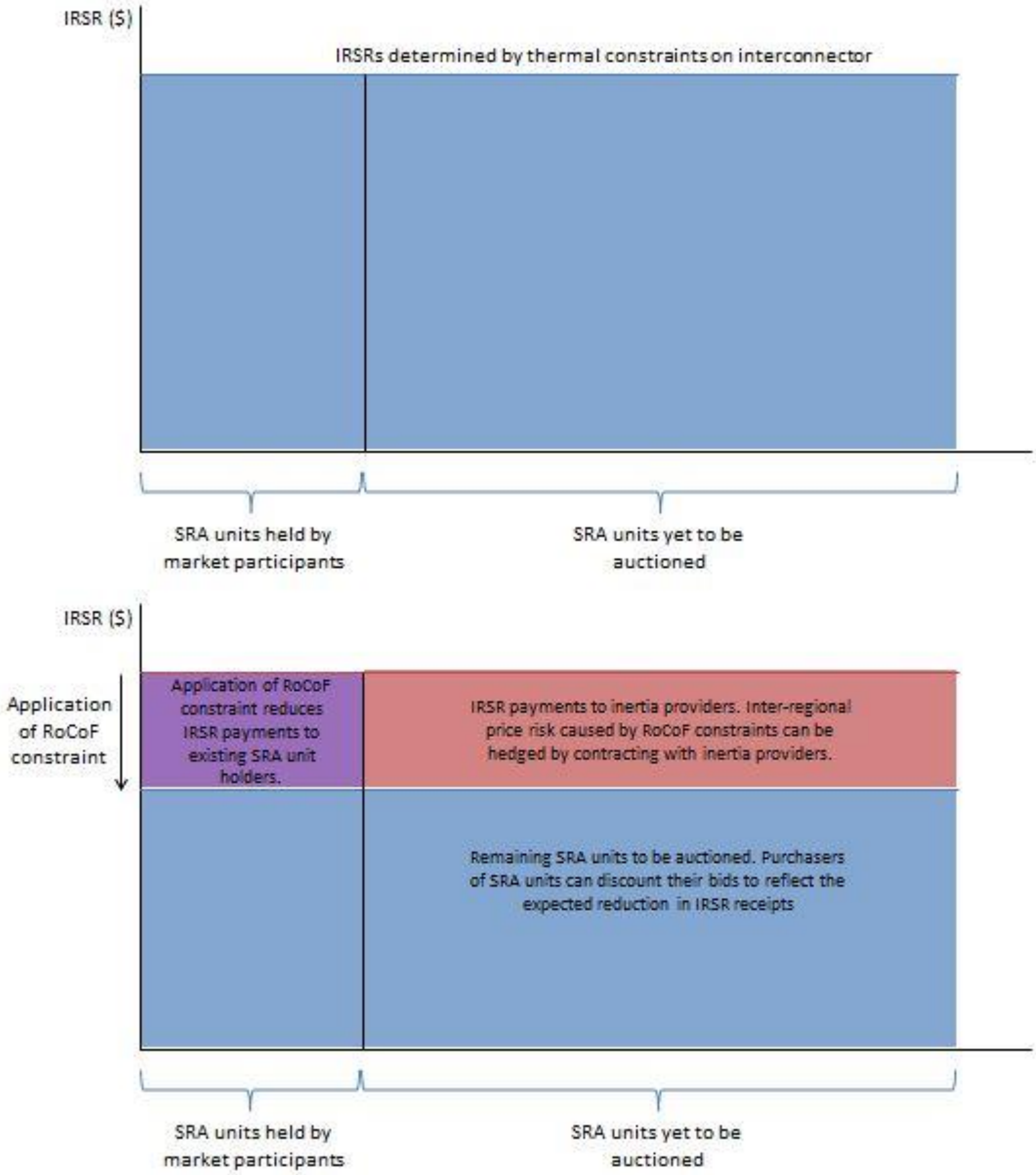
5.5 Implementation

As discussed in section 5.1, the payment of IRSR funds to inertia providers would potentially degrade the effectiveness of SRA units as a potential hedge against inter-regional spot price risk. Market participants may be able to compensate for the reduced effectiveness of SRA units by entering into hedge arrangements with inertia providers to manage the risk of inter-regional price separation caused by binding RoCoF constraints.

IRSR funds would still be paid to holders of SRA units whenever inter-regional price separation occurred that was not caused by a RoCoF constraint. Future purchasers of SRA units would be able to take the presence of the RoCoF constraint into account when bidding at the SRA auction.

However, for existing holders of SRA units, the introduction of the market sourcing approach could mean lower settlement residue revenues than was expected at the time of purchase at auction. This is illustrated in Figure 5.3, which shows the distribution of funds to existing and future holders of SRA units from the introduction of the market sourcing approach.

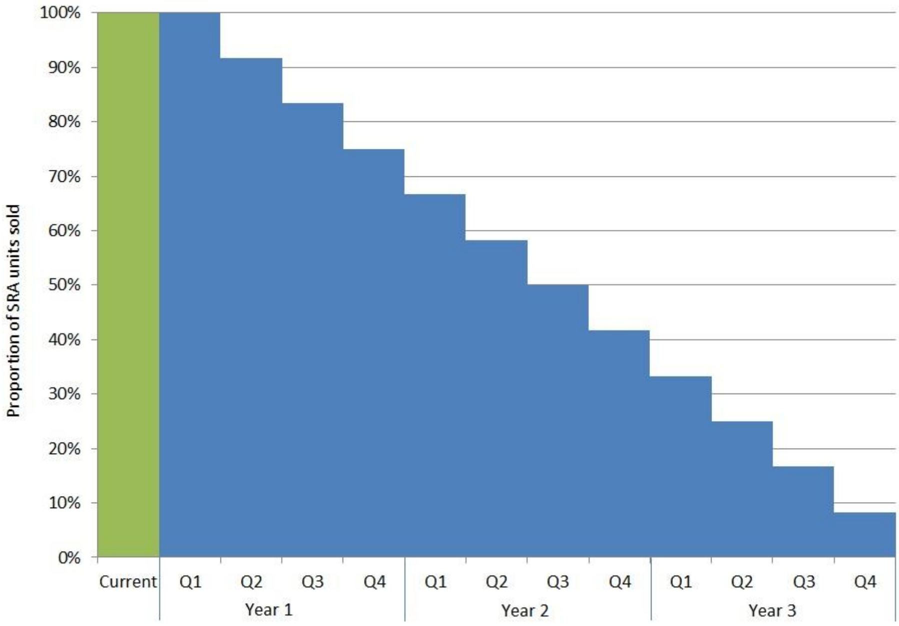
Figure 5.3 Impact of distribution of IRSRs to SRA unit holders



The potential adverse impact on holders of existing SRA units may mean that the implementation of the proposed market sourcing approach to inertia may need to allow time for SRA units to roll off.

Each SRA unit covers a period of approximately three months with SRA units available to be purchased at auctions up to three years ahead. SRA auctions are held on a quarterly basis with 12 tranches covering the three-year period. At each auction, 8.33% of the total SRA units that apply to a particular quarter are available for purchase. Figure 5.4 shows the total proportion of SRA units which have been sold for each quarter just prior to the start of any given three-year period.

Figure 5.4 Forward auction of SRA units



A delay to the implementation of the market sourcing approach would mean that future purchases of SRA units would be able to take into account the potential impacts on IRSRs. Future purchasers of SRA units would factor the possible binding of the RoCoF constraint into the price they are willing to pay at auction. The formulation of the RoCoF constraint would be a key determining factor in the value of SRA units.

However, a delay to the implementation timeframe would also undermine the objective of the proposed market sourcing approach as a means of addressing the immediate issues associated with regional separation. While the introduction of the proposed market sourcing approach may have an impact on the level of IRSR revenue to holders of existing SRAs, it is worth considering that the currently imposed 3 Hz/s RoCoF constraint on the Heywood Interconnector has also likely had a substantial impact on the level of IRSRs but was not a factor that would likely have been considered by purchasers of SRA units up to three years ago.

An alternative option may be to phase in the funding of inertia payments using IRSRs, and during the transition period use an alternative funding approach as described in Section 4.2.

Question 7

Do you see a need to delay implementation of the proposed IRSR funding approach? If so, do you see value in adopting an alternative funding approach in the interim?

6 Lodging a submission

The Commission is inviting written submissions on this consultation paper. Submissions are to be lodged online or by mail by 3 October 2017 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change requests[19] The Commission publishes all submissions on its website subject to a claim of confidentiality.

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

6.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0208. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

6.2 Lodging a submission by mail

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

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

The envelope must be clearly marked with the project reference code ERC0208.

19 This guideline is available on the Commission's website www.aemc.gov.au

Abbreviations

AEMC or Commission	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
FCAS	Frequency Control Ancillary Services
FFR	fast frequency response
FOS	Frequency Operating Standards
FPSS	Future Power System Security
IRSR	inter-regional settlement residue
MNSP	Market Network Service Provider
NEM	National Electricity Market
NER	National Electricity Rules
RoCoF	rate of change of frequency
RRP	regional reference price
SRA	settlements residue auction
STPIS	Service Target Performance Incentive Scheme
TNSP	transmission network service provider
TUoS	transmission use of system