26 April 2017

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Mr John Pierce
Chairman
Australian Energy Market Commission
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Dear Mr Pierce

Australian Energy Market Commission System Security Market Frameworks Review Directions Paper

AEMO welcomes the opportunity to comment on the Australian Energy Market Commission's (AEMC) System Security Market Frameworks Review (Review) Directions Paper.

AEMO agrees that placing an obligation for inertia management on Transmission Network Service Providers (TNSPs) is appropriate, and that it is important to have a framework for procuring inertia that will deliver market benefits. However, AEMO has identified a number of challenges with the AEMC's approach, which we have outlined in our attached submission. We have proposed a modified process for procuring inertia which we consider addresses the intent of the AEMC's proposal, and will better align with the planning processes available to both TNSPs and AEMO. We expect that AEMO will play a key role in identifying requirements and opportunities for additional inertia across the grid.

AEMO has also provided a proposal for a broader strategy for integrating fast frequency response (FFR) into the market, recognising that FFR has value outside of offsetting inertia.

Finally, AEMO broadly agrees with the framework and allocation of responsibilities proposed by the AEMC for managing system strength. AEMO has provided a number of comments and suggestions on how this framework could best be implemented.

AEMO looks forward to engaging further with the AEMC to develop a Draft Determination which meets the technical and practical requirements of the grid. If you would like to discuss the contents of this submission further, please do not hesitate to contact Violette Mouchaileh on 03 9609 8551.

Yours sincerely,

Peter Geers

Executive General Manager, Markets

Attachments: AEMO submission on System Security Market Frameworks Review Directions Paper

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NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA

Attachment A

AEMO SUBMISSION ON SYSTEM SECURITY MARKET FRAMEWORKS REVIEW INTERIM REPORT

Contents

1. Procurement of inertia

The AEMC's Direction Paper outlines a process where AEMO would set a "required operating level of inertia" which would satisfy "a range of, but not all, system conditions". To determine this level, AEMO would model the level of inertia required under a range of scenarios representing different combinations of generator dispatch patterns and system and network conditions. The required operating level of inertia would then be set to meet the requirement. TNSPs would then be required "to provide and maintain [the] defined operating level of inertia at all times".

AEMO agrees that placing an obligation on TNSPs to procure inertia capability is likely to be an efficient approach, integrating well with existing processes and procedures. AEMO supports developing an explicit National Electricity Rules (NER) obligation on TNSPs for when and how inertia capability should be procured. Although TNSPs are already able to procure inertia for both power system security and market benefits under the existing Network Support and Control Ancillary Services (NSCAS) framework, a well-defined requirement and obligation will likely provide clearer signals to the market.

Given that frameworks for procuring inertia will be important for the efficient operation of the NEM, AEMO supports implementing an approach that would encourage the procurement of inertia for market benefits beyond any minimum level required for the resilient operation of the grid.

However, AEMO is concerned that some aspects of this approach do not accurately reflect the real-time inertia requirements of the grid, and may not allow sufficient flexibility to achieve the most economical outcomes. These issues are discussed below, as well as broader technical issues associated with inertia procurement. In Section 2, AEMO presents an alternative approach that addresses AEMO's key concerns, while still aligning with the key elements of the AEMC's proposal.

1.1 Definition of scenarios

To define the required level of inertia, the AEMC has proposed that AEMO would consider a range of scenarios and generator and network conditions. AEMO would then identify the level of inertia sufficient to maintain a resilient operating system in a pre-determined proportion of scenarios (e.g., 90-95%).

AEMO agrees that a scenario based approach is likely to be appropriate, and that setting a standard for inertia could be an effective management strategy. However, the proposed cut-off is ill-defined, and could also be interpreted in a variety of ways:

- "Across all modelled periods in all modelled scenarios, there should be sufficient inertia in 95% of those scenarios"
- "There should be sufficient inertia to meet 95% of periods across all scenarios"

The level of inertia "required" in any particular scenario is also ill-defined, since constraints can be used in most cases to significantly change the inertia requirement for system security, and this is appropriate and efficient in many circumstances. This statement could therefore perhaps be interpreted as the level of inertia that avoids the need to constrain interconnectors (or otherwise minimise contingency sizes) 95% of the time, and/or in 95% of scenarios.

A level set as a "proportion of scenarios" will depend heavily on which scenarios are selected, and not all scenarios are equally likely. "Scenarios" could include the high level assumptions made in the modelling (e.g., future generation mix, demand forecasts, etc.) as well as dispatch scenarios (e.g., different combinations of load, generation and transmission flows).

AEMO does not support a requirement which would be highly sensitive to the choice of scenarios. AEMO considers a "percentage of time constrained" approach, based on short-term market modelling, is likely to be more effective.

AEMO also notes that the AEMC's approach only allows limited ability to consider alternatives to procuring inertia capability that may be more economically efficient. For example, there may be significant protected events that could be reasonably determined as being expensive to manage with inertia. If these scenarios fell below the cut-off, it would be inefficient to impose this requirement on a TNSP (assuming the event could be managed with other options, such as system constraints or a special protection scheme (SPS)).

1.2 Variability of inertia requirement

In practice, the actual inertia requirement can vary significantly, ranging from a minimum level required for the resilient operation of the grid, to a maximum level, above which there would be no recognised benefits to the grid. (In practice, additional inertia would always increase the resilience of the grid, including being able to survive more extreme events. The protected events framework is designed to quantify the maximum resilience which should be pursued in the market.)

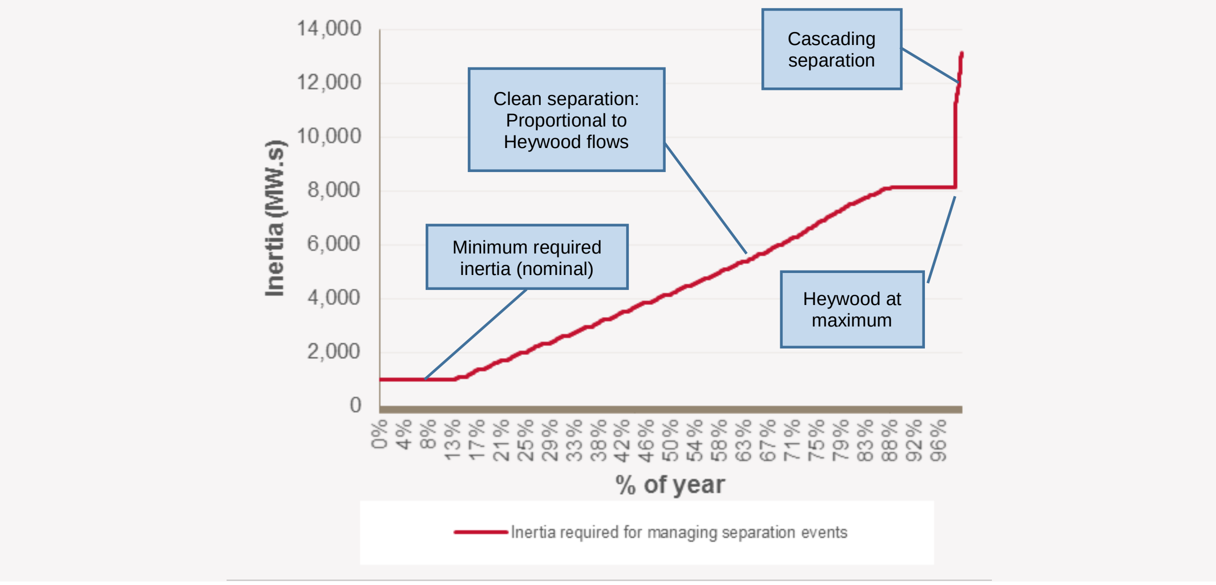
For example, Figure 1 shows an inertia-requirement duration curve for South Australia, based on indicative analysis conducted by AEMO, in response to two potential separation events that could be covered by the protected events framework:

- The non-credible loss of Heywood (referred to as a "clean separation [of SA]"), leading to the islanding of South Australia.
- The loss of significant generation in South Australia leading to a trip of the Heywood interconnector (referred to as "cascading separation [of SA]"). The total loss of generation and transmission flows was then treated as a single contingency. Heywood was assumed to trip at 900 MW[1].

The required level of inertia was set to limit the rate of change of frequency (RoCoF) in South Australia to 2 Hz/s, and a nominal 1,000 MW.s minimum inertia requirement was assumed. AEMO notes that this modelling is only of a single scenario, with an estimated RoCoF limit, and does not necessarily represent the inertia levels required in South Australia in the future. It is shown here for illustration purposes only, to indicate the general shape and trends.

[1] On the 3rd of March, an event resulted in approximately 963 MW of Heywood flows, without disconnection, but maintaining synchronisation at this level of flows cannot be guaranteed in general. See: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Report-SA-on-3-March-2017.pdf

Figure 1 Variability of inertia requirement in South Australia (based upon 2Hz/s RoCoF limit)



This modelling shows that the inertia required to manage separation events in South Australia depends heavily on the flows on Heywood, and can significantly increase when required to protect against more significant events, such as a cascading separation.

1.3 Defining a "required" level of inertia

AEMO suggests that there is no single fixed level of inertia which can accurately capture the inertia requirements of the grid or align with the options available to a TNSP. AEMO has considered several possibilities for a single inertia requirement:

- A requirement to maintain a fixed level of inertia provision
- A requirement to procure a fixed level of inertia capability
- A requirement to procure "top up" inertia to a fixed level

Maintain a fixed level of inertia

The AEMC has proposed that TNSPs would be required "to provide and maintain [the] defined operating level of inertia at all times".

As presented in Section 1.2, the actual inertia requirement for a region is best described by an inertia requirement duration curve, rather than a fixed level. Any fixed inertia requirement is therefore not likely to be the level of inertia required at *all times* in order to achieve a given standard (e.g., operate in "90-95% of scenarios" as discussed in the Directions Paper).

AEMO therefore does not consider it reasonable to require a TNSP to maintain a fixed level of inertia available at all times. This would result in an oversupply of inertia in many periods, and would be an overly onerous requirement on both the TNSP and potential providers. (In practice, uncertainty over the requirement, and inflexibility of potential providers may require "excess" inertia to be dispatched for some periods.)

Requiring a constant level of inertia would also deliver inefficient investment, and potential limit participation to only baseload inertia providers.

Ensure fixed availability of inertia

It may be more appropriate to require the TNSP to ensure the required level of inertia was *available* for dispatch at all times, but not mandate its dispatch if not required. However, this could potentially require the TNSP to contract inertia even in regions where the energy market already delivers sufficient inertia. For example, in Queensland there is an abundance of inertia at present, but this approach may require the TNSP to contract for the full amount of inertia required, to meet their obligations. This could apply immediately from the point where this rule change is introduced.

Although contracts with generators would presumably be comparatively low cost in this case, this would represent an unnecessary cost being passed on to consumers, inconsistent with the National Energy Objective (NEO), and an unnecessary administrative burden on TNSPs.

Procuring “top up” inertia

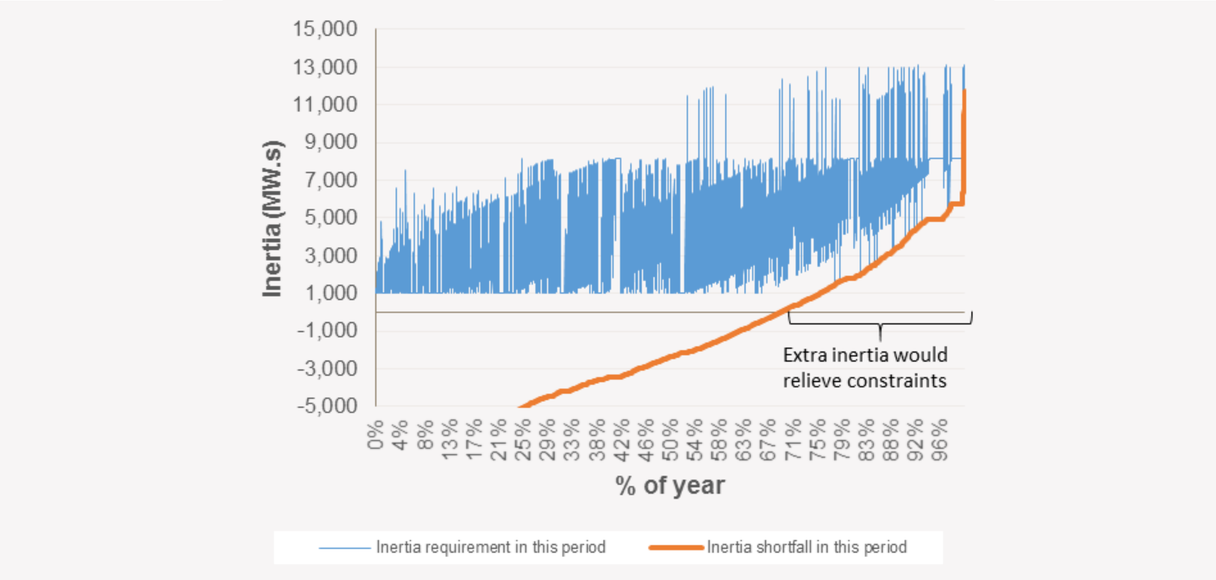
Alternatively, the obligation on TNSPs could be interpreted as “topping up” inertia if a shortfall was predicted. Setting a fixed level to be maintained presents the same issues identified above. Theoretically, the most efficient approach would be for the TNSP to top up the inertia to a level required to avoid additional system constraints in each period – meeting the inertia “shortfall” in each period.

However, this shortfall is likely to be highly variable. For example, Figure 2 presents some indicative near-term modelling of South Australia, showing the inertia required to minimise system constraints (blue), and the corresponding shortfall in inertia delivered from the energy market (orange). This shows that the shortfall is only weakly correlated with the total inertia requirement: to minimise system constraints, additional inertia could be required during times of both high and low inertia requirement. Conversely, there will (in the near-term) regularly be sufficient inertia available from the energy market.

Given the range of options available to a TNSP, it is unlikely that AEMO’s modelling can determine a single “inertia shortfall requirement” that a TNSP could be required to address.

This approach would also need to outline the consequences for TNSPs if the specified level of inertia was not available in real-time, and how this would be managed.

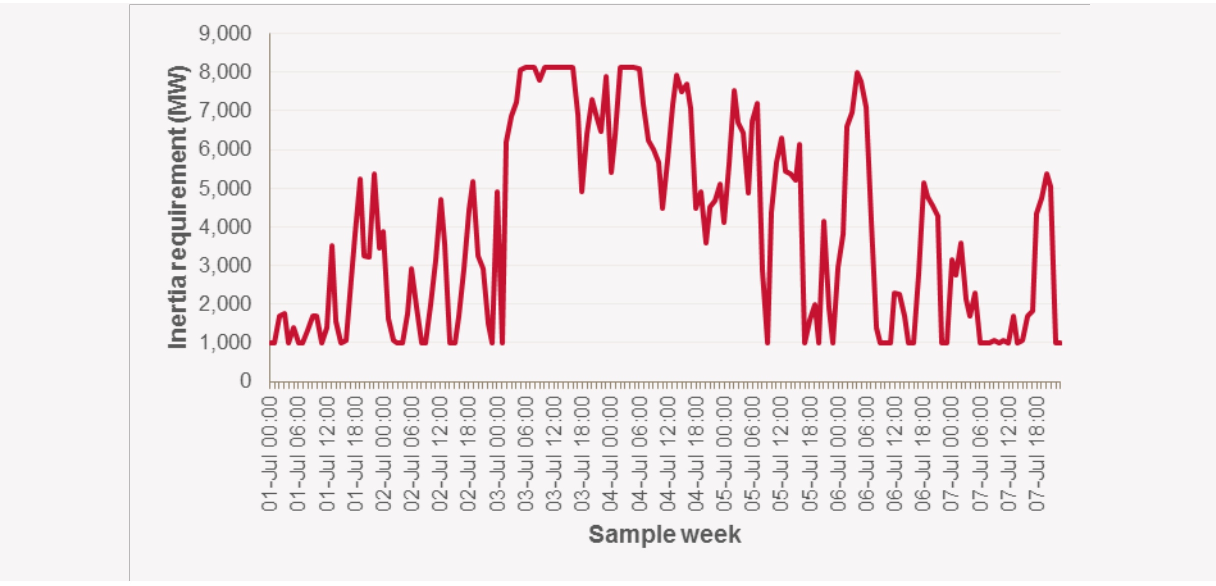
Figure 2 Indicative modelling of inertia requirement and shortfall in South Australia (assuming 2Hz/s RoCoF limit)



1.4 Operational dispatch of inertia

Independent of the procurement method and quantity of inertia, power system operations involves the co-optimisation of inertia and system constraints in real, and close to, real-time. For example, Figure 3 shows the indicative variability of the level of inertia each hour to avoid additional system constraints restricting flows on the Heywood interconnector, and maintain RoCoF below 2Hz/s in the event of separation. In practice, it is unlikely that inertia can (or should) be adjusted with such precision; practical constraints and uncertainty around forecasting will require higher levels of inertia to be committed ahead of real-time.

Figure 3 Potential variability in inertia requirement in South Australia (assuming 2Hz/s RoCoF limit)



Committing inertia would ideally require consideration of:

- The inertia likely to be available from the normal operation of the energy market
- The "additionality" of any inertia provider contracts on that operational state (since committing a new inertia provider may displace an existing inertia provider, if they aren't both contracted)
- The short-run cost of procuring inertia capability versus other power system constraints
- The lead-time for inertia commitment, and the uncertainty in future requirements

AEMO recommends that the responsibility for dispatching inertia sit with AEMO. This is similar to other grid services procured by the TNSP, such as NSAs for reactive power. Once procured by the TNSP, AEMO should be advised of the contracts, and develop procedures for committing inertia if it was required. This commitment would sit naturally with the first half-hourly day-ahead pre-dispatch run (midday on the preceding day), but this would require contracts with a reasonably short notification time.

Contracts for inertia

Given that there may be relatively few providers of inertia in some regions, it will be important to structure any scheme so that it does not alter participant incentives in the energy market. It will also be important that contracts for inertia can be usefully dispatched in (or close to) real-time to deliver value to the grid.

AEMO suggests that restrictions be placed on the inertia procurement contracts, determined in consultation with AEMO. The TNSP should consider how contracts could be dispatched operationally, and the interaction of inertia providers and the energy market. Potential contracting options that would assist in managing inertia and the grid could include:

- **Day ahead notification.** This would balance improvements in forecasting closer to real-time and practical aspects of unit commitment. In particular, it may be efficient to be able to commit inertia for the following trading day at midday the previous day, in line with AEMO's existing pre-dispatch process.
- **Intra-day flexibility.** Committing inertia in multi-hour blocks, rather than for a whole day, would allow flexibility for additional inertia to complement the natural inertia from the energy market. For example, procuring additional inertia in six hour blocks would naturally complement key market periods:
  - 4am to 10am: morning ramp
  - 10am to 4pm: solar peak (a potential time of low inertia)
  - 4pm to 10pm: evening peak
  - 10pm to 4am: overnight low demand
- **Contracts for differences.** Structuring payments as contracts for differences (CfDs), where inertia providers that also participate in the energy market would be paid the larger of a contract floor price and the wholesale energy market price, thereby minimising windfall gains.
- **Minimise market distortions.** Avoiding contracts that provide start-up costs, which could incentivise providers to seek to be committed for inertia before being committed for energy
- **Preserve flexibility.** Short-duration contracts which can be revised if outcomes are not as expected.

- **Price caps or regulated pricing**. The relatively small number of providers of inertia contracts in some regions may necessitate measures to ensure competitive offers can be procured. For example, the prices associated with these contracts may need to be regulated or limited.

1.5 Risk of stranded assets

AEMO notes that there are some foreseeable “stranded asset” risks, such as the introduction of an SPS, which will fundamentally change the amount of inertia required (and how it is calculated). These could be managed by having a forward projection of the amount of inertia required now and into the future, such that higher amounts may be required initially, but this reduces over time.

This would be incorporated into the TNSP’s RIT-T, and would influence the proportion of short term and long term contracts required, and over what duration.

2. AEMO proposal for inertia procurement

AEMO is proposing an alternative approach for procuring and managing inertia which addresses the concerns identified in Section 1 above. This proposal is similar "in spirit" to the AEMC proposals, but with some important differences and clarifications. In particular, it aligns with the AEMC goal of operating a system without inertia-related constraints in most, but not all, conditions, but allows for greater opportunities for economic assessment and trade-offs.

The proposal for inertia procurement can be summarised as follows:

1. A *system standard for inertia* would be defined in the NER. This standard will require that:

    a. the system operates without inertia-related constraints binding at least a certain percentage of the time (to be set in the NER), and

    b. the inertia available for dispatch is always above a workable technical minimum. This level is to be determined by AEMO each year.

    The standard could be set differently for each region or sub-region, as required.

2. In the NTNDP or another planning process, AEMO would assess whether the standard is likely to be met in future years, taking into account existing and potential system constraints. If not, AEMO would estimate the appropriate actions to be taken to meet the standard, defining an "inertia gap". This does not representing a binding figure, but would be expected to inform the TNSPs' assessment of the system standard for inertia, and alert potential providers of inertia.

3. TNSPs would be required to consider the system standard for inertia (in their APR or a separate process) and address any gap, such that the standard will be met, using the RIT-T process to identify the least cost combination of actions. These actions could include installing synchronous condensors or contracts with generators, but could also include new transmission, implementing an SPS, using FFR, contracts for run-back schemes with generators vulnerable to RoCoF, or any action that will reduce the binding of constraints, and therefore allow the standard to be met.

4. TNSPs would also be required to undertake a process (APR or RIT-T) each year to assess whether additional inertia (above what was required to meet the standard) would be justified under a RIT-T. If positive benefits are identified relative to the standard, TNSPs would be required to undertake the scenario with the highest NPV outcome.

AEMO would then have operational control of inertia, co-optimising the dispatch of inertia with other grid management options in (or close to) real-time. TNSPs would be expected to consult with AEMO on the required design of any contracts for inertia, and AEMO would prepare standard procedures for how inertia would be dispatched.

These aspects are discussed further below.

2.1 System Standard for Inertia

AEMO is proposing that a system standard for inertia is introduced. This system standard will have two components, as follows:

2.1.1 Percentage of time constrained

The first component of the system standard would require that the TNSP operate their network without inertia-related constraints for some percentage of the year, consistent with the AEMC's proposal of a system that is generally operated unconstrained. This value should approximate the level of binding of inertia-related constraints that corresponds to a "practically functional system", of the type that would be desired by most consumers. This is analogous to the 0.002% USE reliability standard: imposing an expectation of minimising the impact of inertia shortfalls, but allowing for flexibility in how this standard is met.

The AEMC's Directions Paper suggested each region should operate unconstrained in 90-95% of scenarios; this could suggest an intention that the system should operate unconstrained by inertia 90-95% of the time. The precise percentage of periods would be set in the rules by the AEMC (perhaps via the Reliability Panel), and may require independent modelling. AEMO expects that this level would be informed by long-term modelling of a range of scenarios, assessing efficient levels of inertia. The level set in the NER could then be determined in consultation with AEMO, industry and other relevant parties. This standard could be set differently for the mainland and Tasmania, similar to the existing FOS.

As the standard is inherently probabilistic, it may be that the standard is not met in a given year despite best practice analysis by the TNSP. AEMO suggests that this would not represent a failure to meet the standard, provided the initial modelling was reasonable in light of the information available.

Consideration would need to be given to how periods of planned or unplanned outages would be treated (where these would result in stricter inertia constraints). For example, these could be treated through a probabilistic analysis by the TNSP (similar to the 0.002% USE reliability standard) or by only defining the standard for system normal conditions (such as only considering system normal conditions, similar to the FOS).

An alternative possibility for defining this standard would be as a maximum market impact (in dollars). This would capture the fact that some constraints may bind regularly, but with a low market impact, whereas other constraints may bind very rarely but have an extreme market impact. Directly defining the standard in terms of the total allowed market impact (related to the marginal cost of congestion) would avoid this issue, and could be benchmarked against the cost of installing synchronous condensers. However, it may be challenging to precisely calculate when the standard has been met, due to the lack of a counterfactual case against which to calculate the total cost of binding constraints. This should be explored by the AEMC in the definition of this standard.

Identification of constraints contributing to the standard

This proposed approach will make it extremely important to define the set of constraint equations that are considered to be related to inertia. Constraints that directly relate to RoCoF are clearly included, and have by far the largest market impact at present. This is likely to continue to be the case in future. However, there are some practical complexities to bear in mind:

- Transient stability constraints depend upon inertia in some regions, but other TNSPs have elected to define their transient stability constraints in a manner that does not directly depend upon inertia. This may mean that some degree of consistency must be introduced, and the manner in which these constraints are defined may change over time, at the TNSPs discretion. However, transient stability constraints are typically of low impact, at present, so this is not likely to be a significant issue in the near term.

- In theory, transient stability constraints can have negative inertia terms, meaning that a higher inertia (in the importing region) can cause the constraint to bind more. This may have unintended and complex implications. However, as stated above, transient stability constraints are typically of low impact, at present, so this is not likely to be a significant issue in the near term.
- The Fast Raise and Lower FCAS requirements in South Australia and Tasmania include inertia terms as well as a minimum requirement. Therefore, these constraints bind in all periods, but this does not indicate a lack of inertia in all periods. These constraints could probably be reformulated to extract the inertia-dependent component as a separate constraint.

Furthermore, there may be new constraints defined which may or may not directly include inertia terms, and which may or may not be relevant to the inertia standard.

These could be managed through a process identifying constraints that should contribute to the inertia standard, undertaken by AEMO in consultation with the relevant TNSP. This could include restructuring some constraints to separate out the inertia-driven and non-inertia driven terms. Adopting this approach will require AEMO to be transparent about the role of inertia in developing new constraints, and ensuring that constraints don't artificially inflate the need for additional inertia.

AEMO notes that if constraints affect multiple regions, there may need to be a framework for apportioning responsibility for meeting respective standards.

Planning role for AEMO

It is expected that AEMO would have a key role in:

- Developing the system constraints that would define the technical operating envelope of the grid
- Conducting analysis of whether the inertia standard is likely to be met under a range of likely scenarios
- Identifying strategies that could be undertaken to meet the standard, while also considering other aspects of the operation of the market including locational requirements

These roles align well with AEMO's current NTNDP responsibilities, but could also be undertaken through a separate process. AEMO is not proposing to identify a binding inertia shortfall or similar action, but expects that this analysis would inform both potential inertia providers of upcoming opportunities and providing a starting point for the TNSPs' subsequent analysis.

It is important that AEMO be able to propose new constraint equations to apply in the NTNDP and RIT-T assessments, even if those constraints don't yet apply. For example, given the level of RoCoF risk in SA at present, and uncertainty over RoCoF withstand capabilities, it may be prudent to reduce the 3Hz/s RoCoF constraint to a lower level (such as 1 Hz/s or 2Hz/s). This would result in market impacts, but these could be avoided if sufficient inertia was available. The preferable outcome would be to include a lower RoCoF constraint level in the NTNDP and RIT-T assessments, in anticipation of changing the limit when the inertia was available, and for the TNSP to procure inertia services on that basis (rather than based upon the present RoCoF limit of 3Hz/s). This would allow serious emerging issues to be addressed promptly, in a way that limits impacts on consumers. It is proposed that AEMO would determine the set of constraints to apply in the NTNDP and RIT-T process, in collaboration with the TNSP.

2.1.2 Workable Technical Minimum

The second component of the system standard would require TNSPs to make available for dispatch a minimum level of inertia at all times. This would represent AEMO's assessment of a minimum requirement to run a resilient power system, or a *workable technical minimum*. AEMO would determine this level each year for the NTNDP, based upon a defined procedure. It would represent the level of inertia under which the region could be operated with high confidence of system security, taking into account any credible and protected events, but allowing the use of constraints to limit contingency sizes.

Depending on how protected events and constraints are managed, this requirement could result in the first percentage of time constrained requirement being automatically met.

AEMO should consult on and publish its methodology for establishing a workable technical minimum level of inertia, having regard to the inertia objective and principles that are set out in the Rules.

2.2 TNSP to procure additional inertia capability if least-cost

As proposed by AEMC, TNSPs would be required to undertake a RIT-T (if expenditure exceeds the RIT-T threshold) to determine the least-cost strategy for meeting the system standard for inertia. The TNSP would be required to meet the standard even if the RIT-T does not identify a positive NPV, consistent with AEMC's proposal.

AEMO also proposes that a separate obligation be placed on TNSPs to investigate and undertake additional actions which would be beneficial, above the level of the system standard for inertia.

NSPs would be required to conduct additional RIT-T analysis of the inertia procurement or constraint alleviation options available to them to determine whether additional inertia (above what was required to meet the standard) or other actions to reduce the binding of constraints, would be justified under a RIT-T. The NPV would be calculated relative to any action required to meet the system standard for inertia, i.e., to determine whether *additional* action would be justified on an NPV basis. If a net benefit is identified, TNSPs would be required to undertake the scenario with the highest NPV outcome.

This places an active obligation on TNSPs to undertake and execute economically beneficial RIT-T scenarios.

It may be that this additional level of inertia results in the region exceeding the inertia standard. This is consistent with the idea that the inertia standard represents a "backstop" level of inertia, and greater economic benefits should be pursued if warranted.

2.3 Operational dispatch of inertia

It is proposed that AEMO is responsible for the dispatch of inertia in (or close to) real-time. There is a risk that this dispatch will conflict with the implicit assumptions of the TNSP; although the TNSP may have procured contracts that *could have* alleviated system constraints, it may be lower cost not to execute those contracts. This could result in the inertia standard not being met.

AEMO considers that these short-run decisions are appropriate. If the standard is not met, in their next review period, the TNSP would be expected to either:

- Procure additional inertia capability
- Procure alternative, lower cost, sources of inertia capability
- Negotiate to reduce the short-run cost of any inertia contracts

This is most likely to be challenging during the transitional period where options for inertia may be limited, and transitional arrangements will need careful consideration. However, it may also place competitive pressure on inertia providers to offer contracts which could credibly be activated in the short-run.

AEMO proposes that TNSPs would be required to consult with AEMO on the structure of any contracts for inertia, considering how these would interact with AEMO's systems and the value of additional flexibility.

AEMO would develop public inertia dispatch procedures that TNSPs could use in their RIT-Ts, and which would provide transparency for potential inertia providers.

2.4 Advantages of this approach

This approach has several advantages:

- ***Trade-off of constraints vs inertia*** – The AEMC approach requires TNSPs to maintain a fixed level of inertia at all times, even if it is not required to avoid constraints. This proposed approach provides a more nuanced assessment of the economic trade-off between the use of constraints, the procurement and dispatch of inertia capability, and other mitigation strategies.
- ***Avoiding the fixed inertia requirement*** – Furthermore, the AEMC process would require AEMO to determine a fixed inertia requirement. This is inherently challenging:
  - The inertia requirement varies from period to period, and therefore is represented by a duration curve, rather than a flat quantity. How should this obligation be defined for the TNSP?
  - Given the complex interaction with unit commitment in the energy market, how would AEMO determine the amount of inertia required? The inertia shortfall correlates very poorly with the total amount of inertia, meaning that it is inherently difficult to calculate a flat amount of inertia capability to be procured at all times.
  - If a shortfall is forecast, does the TNSP need to procure the entire amount of inertia projected to be required? Or just address the shortfall? What penalties would apply to the TNSP if an inertia shortfall still occurs?

  The proposed approach addresses these challenges by clarifying the system standard to be met (in terms of the amount of binding of constraints), rather than defining a level of inertia to be met directly.
- ***Flexibility in approach*** – Both this and the AEMC process would place obligations on TNSPs to procure additional inertia capability. However, AEMO's approach provides greater flexibility for the TNSP to meet the obligation. The TNSP is not required to procure inertia to any fixed level; instead, the TNSP would evaluate the contribution of each available *option* towards meeting the standard. This implicitly

allows some technical and economic trade-offs while still requiring a fixed outcome. Furthermore, the inertia standard focuses on the requirement (maximising the use of the grid) rather than on a specific solution (e.g., buying inertia). The TNSP therefore has a range of options available:

  - Procuring inertia from synchronous condensors
  - Procuring inertia through generator contracts
  - Incentivising new generators with inertia capabilities, such as solar thermal with storage
  - Procuring FFR, if AEMO's constraints allow FFR to reduce the binding of inertia-related constraints
  - Installing an SPS, which would relieve inertia-related constraints, or procuring other sources of fast-acting load shedding.
  - Contracting with generators for runback schemes which would reduce contingency sizes at critical times
  - If generator RoCoF withstand capabilities were a limiting factor, contracting with vulnerable generators to not operate at certain times
  - Building new transmission to alleviate constraints

- ***Probabilistic*** – By being closer to a probabilistic standard, variable providers of inertia or alternative services could be utilised. These providers may be effectively excluded under the AEMC's proposal. For example, wind and solar PV can provide FFR, but are not available at all times. If the TNSP were required to procure inertia to a fixed level, these services would be unlikely to be selected to contribute. Under this approach, they may provide value through reducing the severity of inertia constraints at certain times, making it easier for the TNSP to meet the standard.
- ***Consideration of actual contingency events*** – This standard would implicitly require the TNSP to consider potential contingency events in their modelling, as AEMO's inertia-related constraints would include consideration of credible and protected contingency events. This automatically accounts for the need that the post-contingency inertia is sufficient. In contrast, procuring to a fixed level of inertia would require separate consideration of loss of inertia on a contingency.
- ***Opportunities for growth*** – If the penetration of non-synchronous generation increases over time, the inertia shortfall is also likely to grow. This would create a naturally growing market for new inertia providers to address the shortfall. This will allow learning from previous RIT-T processes and provider tenders to be applied to subsequent stages, and allow new technologies or lower-cost providers opportunities to contribute to a cost effective mix of providers.

2.5 Longer-term development pathway

AEMO supports moving towards more dynamic procurement mechanisms for inertia in the future, provided they are compatible with the technical and operational requirements of the power system. AEMO sees there is value in working towards a hybrid approach where some share of inertia services are procured through a competitive market. This could allow new participants (including new and existing generators) to apply to "top-up" the operational inertia available to be dispatched by AEMO.

This could initially operate on a day-ahead basis, but it may be possible to move towards closer to real-time in the future. For example, in Tasmania, inertia is available from hydro generating units operating in synchronous condensor mode. These units could conceivably be dispatched in close to real-time (5-30 minute notification periods). In contrast, some generator contracts may require multi-hour or day-ahead notification to manage start-up times and fuel procurement requirements.

In the same way that AEMO is proposing to dispatch inertia contracts procured by the TNSP, it could also consider offers made by other potential providers. Placing appropriate requirements on TNSP contracts for inertia (e.g., mandating at least day-ahead response times) would provide a transition pathway to a more competitive mechanism, and allow inertia procured by the TNSP to participate in the hybrid market.

If AEMO determines that the level of inertia required could be reduced if FFR is available, FFR providers could be enabled at the same time, or could be procured closer to real-time. This would create a clear opportunity for variable Generators to provide FFR as the market conditions and underlying fuel availabilities allow.

Pricing of inertia

Instead of paying inertia providers based on contracted prices, in principle it would be possible to derive the value of inertia from the appropriate inertia constraints. In periods when there is no shortfall of inertia, the price of the constraints would be zero, and expensive constraints would result in a high value of additional inertia. If this price were paid to inertia providers, it could create a natural market for inertia.

In practice, this may be challenging to implement, as procuring the full amount of inertia required to alleviate constraints would result in no payment to those providers, even though they were delivering value. However, a price could potentially be extracted from a pre-dispatch run to indicate the value of “missing” inertia, provided that issues with market power and strategic bidding would need to be considered. Using the marginal value of constraints approach to inertia pricing may also avoid the difficulty in the marginal pricing of “lumpy” inertia supply.

2.6 Cost recovery arrangements

AEMO supports investigating a range of cost recovery arrangements, while noting that there is value in transparent, straightforward cost recovery mechanisms.

In practice, causer pays mechanisms for inertia are likely to be complex. In particular:

- They need to provide clear price signals, incentivising actions that could credibly reduce those costs (this could also include long-term price signals)
- It may be challenging to impose additional costs on existing Generators
- Charging Market Participants for not doing something (in this case not providing inertia) is not in line with most other market services.

AEMO also notes that recovering costs based on the level of inertia a participant provides is complex (given that there is no mechanism designed to value the inertia provided from participants not contracted with a TNSP). In particular, recovering costs only from non-synchronous generation providers is problematic, given that “no inertia per MW” and “low inertia per MW” are not qualitatively different from an operational perspective.

Analysis by consultant GE for AEMO has suggested that there may be some limited opportunities for generating units to increase their RoCoF withstand capabilities. This would increase the RoCoF tolerance of the system, and allow AEMO to alleviate RoCoF constraints. Therefore, it may be beneficial to target the costs of inertia services at units with the lowest RoCoF capabilities, to incentivise these adjustments. Activities that may increase RoCoF withstand capabilities could include tuning of protection schemes and control schemes, which may be achieved at a relatively low cost. GE has advised that some of these actions would also have SRMC implications. For example, to avoid lean blowout effects, gas turbines can tune their control settings to have a less lean air/fuel mixture. This is less efficient, resulting in a higher SRMC. Accurate price signals would help to incentivise this behaviour, but the level of price signal required would be unique to each plant.

However, introducing price signals based upon RoCoF withstand capabilities would require an accurate understanding of RoCoF withstand capabilities. This is likely to be challenging, requiring difficult and expensive testing that may not deliver value to consumers. Furthermore, beyond initial tuning of control schemes and protection schemes, the augmentations required to substantially improve RoCoF withstand capabilities are likely to be prohibitively expensive for many units. This may limit the effectiveness of “causer pays” price signals, and mean that the complexity involved in implementing this approach is not warranted.

Additionally, modelling conducted for AEMO by Entura has suggested that the RoCoF withstand capabilities of a particular unit will change, depending upon the operation and proximity of surrounding units. Therefore, to determine the RoCoF withstand capability of the system, the cluster of interacting units must be considered together. This makes it technically impractical to allocate RoCoF “responsibility” to an individual unit.

3. Procurement of FFR

AEMO supports the intent of the AEMC proposal to implement a relatively simple approach to encourage investment in FFR capabilities initially, transitioning to a more sophisticated arrangement in future once sufficient experience has been gained.

Modelling and analysis conducted for AEMO by external consultant GE has indicated that FFR is a valuable service in the future, and provides a wider range of lower cost options for frequency control[2]. It can serve three potential roles, each of which will require different technical capabilities:

1. A very fast response implemented through a special protection scheme (SPS) or similar, for assisting in managing large contingency events (particularly non-credible protected separation events). This would likely triggered by direct event detection, such as the loss of an interconnector or specific generators, and would displace the use of involuntary under frequency load shedding.
2. A new faster type of contingency Frequency Control Ancillary Service (FCAS), typically used for managing credible contingency events. This would operate similarly to the existing 6 second contingency FCAS (R6/L6), triggered by local frequency measurement, but would respond in a faster timeframe (such as 0.5 - 1 seconds).
3. A new faster type of regulation FCAS, used for managing minor imbalances in a lower inertia system. This could operate based upon local frequency measurement (as a droop response, for example), with a rapid response time (such as 0.5 - 1 seconds). It could alternatively be based upon a faster AGC signal if desired[3].

FFR could be included immediately in the special protection scheme design underway at present for the Heywood interconnector. This could also be a suitable response to the definition of new protected events, and would presumably be implemented by the relevant TNSP, through a RIT-T process.

The use of FFR as a new, faster type of FCAS (roles 2 and 3) is not essential immediately. However, AEMO's projections suggest that inertia levels will fall sufficiently over the coming decade or two such that it is no longer possible for typical synchronous governor responses (providing the R6/L6 services) to act rapidly enough to meet the Frequency Operating Standards (FOS). Similarly, the response of the present regulation service may no longer be adequately rapid to meet the FOS. At this point, it will become extremely valuable to have a large, competitive pool of FFR providers available. This will allow the market to operate with lower inertia levels when FFR is available, providing a wider range of options to meet the FOS. Given the very low costs likely to be associated with FFR services from many providers, the value to consumers from having this large pool of providers available could be very substantial.

Significant volumes of new generation and storage are anticipated to be installed over the next five years. These technologies have the potential to include FFR capabilities. Including these capabilities in the initial design and installation is significantly lower cost than later retrofit.

It could be argued that potential FFR providers should include these capabilities in anticipation of future market opportunities. However, in the absence of clearly defined

[2] https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/FPSSP-Reports-and-Analysis

[3] This is similar to the Enhanced Frequency Response (EFR) service introduced in Great Britain (based upon local frequency measurement and a droop response), and to the dynamic regulation service in PJM (based upon response to a fast AGC signal).

technology specifications or revenue opportunities associated with that service, new entrants are unlikely to be able to justify to financiers the additional (incremental) expense associated with including these capabilities. This constitutes a form of market failure, which this proposal should aim to address.

Therefore, AEMO proposes that the transitional FFR mechanism should achieve two objectives:

- Ensure a large, competitive pool of FFR providers is available in future, when it will offer substantial value to consumers.
- Allow AEMO and other market participants to gain practical experience with a wide range of types of FFR providers, ensuring these services can be used effectively and with high confidence when they are ultimately required.

3.1 Substitutability of inertia and FFR

Although FFR and inertia are closely related services, and the quantities required for each will be inter-dependent, they should be considered as two distinct services, with different roles and purposes. FFR and inertia are not directly interchangeable, and an effective procurement framework will recognise the range of benefits and impacts of each separately, and will not require direct interchangeability.

In the near term, the need for inertia is related to surviving non-credible, protected events such as separation of a region. These events are associated with very extreme RoCoF levels (2-3Hz/s). This means that for FFR to effectively "substitute" for inertia in managing these events, it would need to act very rapidly to arrest the frequency decline. For example, a RoCoF of 2Hz/s would require a full FFR response in less than 500ms (to avoid UFLS). A RoCoF of 3Hz/s would require a full FFR response in less than 330ms. Although many FFR technologies are capable of response times in this realm, a response triggered by local frequency measurement is unlikely to be sufficiently robust and reliable, and could be prone to false triggering. This is discussed at length in GE's report to AEMO[4]. A direct event detection approach is likely to be more technical viable at these timeframes. This could be utilised in a SPS, for example.

The implications are that in the near term, the type of FFR that is useful is very fast, direct event triggered, and used for managing protected events (probably as a part of an SPS). Slower FFR, such as wind inertia-based FFR[5], is not technically capable of assisting with management of protected events, and therefore is technically incapable of substituting for inertia in the near term. The AEMC's proposed approach of allowing the TNSP to procure FFR if it can substitute for inertia will therefore not achieve any investment in FFR of this type.

However, in the longer term, slower FFR will become valuable for managing credible contingency events, allowing the FOS to be maintained at lower cost. To illustrate, Figure 4 shows the RoCoF exposure for credible contingency events on the mainland NEM. For credible events on the mainland, AEMO must maintain the frequency within the containment band (49.5Hz). If the governors delivering the R6 service are activated at 49.85Hz (as defined in the Market Ancillary Services Specification), this allows only a 0.35Hz drop to

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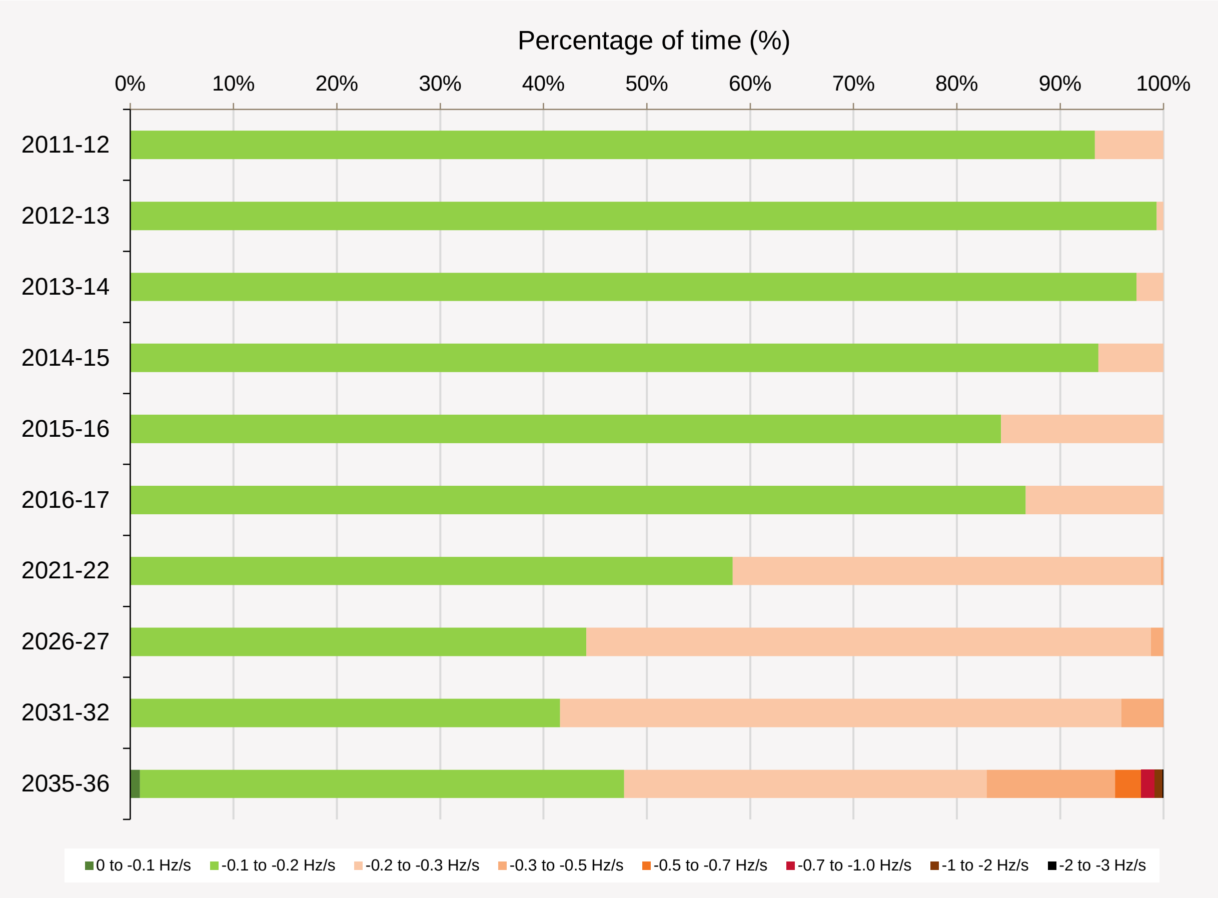
[4] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf

[5] Wind inertia-based FFR has a typical response time of 1-2 seconds. There may be potential to tailor this for somewhat faster response times, but manufacturers have advised that there are likely to be tower stress constraints that will limit the speed of response.

arrest the frequency decline. The governors delivering the R6 service typically take several seconds to deliver a useful response. This means that RoCoF levels above around 0.2Hz/s may lead to challenges meeting the FOS, for credible events. As shown in Figure 4, RoCoF may exceed these levels for credible events on the NEM mainland around 50% of the time from 2021-22. From this time, FFR will become an important alternative to maintaining large quantities of inertia in most periods. For RoCoF in the range of 0.2Hz/s, an FFR response time of 1-2 seconds is adequate and useful, and this is in the realm of capability of most wind inertia-based FFR services.

Figure 4 Mainland NEM: Negative RoCoF exposure for credible contingencies (loss of largest generating unit, or Basslink flows into VIC)



Furthermore, it is likely to be preferable for a future FFR service for managing credible contingency events to be triggered by local frequency detection, rather than direct event detection (similar to existing FCAS). This would allow general protection against all contingency events, rather than just certain defined (protected) events. The challenges around local frequency detection necessitate that this service is somewhat slower, to ensure sufficient robustness, and avoid risks of false triggering. With the AEMC's proposed approach, there would be none of this type of FFR developed in the NEM, so it would not be available when required in future. Furthermore, AEMO would not have developed any experience in managing this important and very different kind of FFR.

To summarise, FFR must be thought of as multiple categories of services, which can serve different roles and purposes. The AEMC's proposed approach would not allow any investment in some of the lowest cost forms of FFR (slower FFR, triggered via local frequency detection) until a much later date, when it can be demonstrated to "substitute" for inertia, with regards to credible contingency events. This type of FFR cannot "substitute" for inertia in the near term, because it is not fast enough to address non-credible protected events.

A number of other important issues related to the AEMC proposal can be summarised as follows:

- Given the novelty of large low inertia systems, and the global inexperience with the use of FFR in general, AEMO believes it will take several years before there is sufficient operational certainty to approve any substitutions with a sufficient degree of certainty. Therefore, this approach would likely lead to very little investment in FFR in the near term. This will miss important opportunities to include this capability (at a small incremental cost) with new participants entering the market.
- Variable FFR providers (such as wind and PV) may not be able to easily contract with TNSPs as a substitute for inertia, given their variable availability. As a rule of thumb, wind inertia-based FFR can typically provide around 10% of the wind farm operating level in FFR. This means that the FFR service will only be available when the wind farm is operating at higher levels, which may not correlate exactly with the periods when there is an inertia shortfall. Therefore, the TNSP is more likely to prefer FFR solutions with firm availability, such as storage technologies. Wind and PV provide some of the lowest cost options for delivery of FFR in future, and will be able to deliver a useful service in many periods. The intention of the initial (transitional) mechanism is to develop a large pool of FFR capability, and to allow AEMO and the market to gain experience with these technologies. This is not likely to be achieved effectively by the mechanism proposed by the AEMC, since wind and PV technologies are not likely to be included.

AEMO therefore proposes that focusing on quantifying an immediate trade-off between FFR and inertia (as proposed by the AEMC) is not optimal. The long term framework should allow this co-optimisation in future, but the immediate objectives (as described above), are not well met by this framework. A more suitable framework is proposed in the following section.

3.2 Generator Obligations

The AEMC has proposed a mandatory requirement for FFR capabilities on new entrants. AEMO supports the intention to develop a large pool of these capabilities for the future, to enable eventual transition to a liquid, competitive and effective market for FFR (or alignment with whatever FCAS framework is in place in future). However, mandating this capability has a number of challenges:

- The definition will need to be highly technology specific:
  - For example, the sought-after capability from wind farms is inertia-based FFR, which allows wind farms to deliver FFR by drawing upon the inertia in the drive train, and does not require that the wind farm is pre-curtailed to deliver a raise service. However, if the obligation simply specifies the capability to ramp upwards rapidly, wind farms can include this capability by utilising a pitch control approach. This would require the wind farm to be pre-curtailed to deliver FFR. The capability would be present (meeting the obligation), but the

costs to deliver this service in practice at a later date when it is required would be high (due to the opportunity cost of spilled energy). To ensure the desired capability is included, the specification will need to be highly specific, and related only to wind farms.

  - A similar challenge exists for utility-scale photovoltaics (PV). As highlighted by GE in their FFR report to AEMO[6], PV plant may be able to design their inverters to have a short term overload capability that allows useful FFR delivery, where the solar field is oversized compared to the inverter. This would allow FFR to be delivered without pre-curtailment. However, this capability would need to be specifically required (and would be defined differently to the equivalent capability in a wind farm), since PV plant could meet an obligation for fast FFR raise simply by ramping controls (which would require pre-curtailment to deliver useful FFR).
  - The obligations for storage technologies would need to be specified differently from wind and PV capabilities, since at present there isn't any mechanism by which storage technologies can deliver FFR without maintaining sufficient headroom. Utilising short term overload capabilities for inverters may be possible in future, but this is not common practice at present.
  - It is unclear the degree to which synchronous plant can deliver a useful FFR service in the timeframes required. Some are likely to be capable, while others will not have a sufficiently rapid governor response.
- Due to the need to specify the obligation in a highly specific way (and differently for each technology), the technical specification of the obligation would probably need to evolve over time, as technology capabilities change over time. Technology in this area is advancing rapidly.
- Certain important FFR providers, such as demand-side participants, and aggregated distributed energy resources, are not likely to be captured by an obligation approach. This means that these providers may not form a significant part of an active FFR market in future, despite their significant capabilities and potentially low costs. To access the capabilities of these technology types, an incentive approach is likely to be more effective than technical mandates.

For these reasons, AEMO does not recommend that a mandatory generator obligation for FFR capability is implemented at this time. An alternative approach is proposed in the following section.

6 https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017-03-10-GE-FFR-Advisory-Report-Final---2017-3-9.pdf

4. AEMO proposal for FFR procurement

4.1 Overview

The proposal for FFR procurement can be summarised as follows:

1. In the long term, the objective should be to move towards alignment with the existing FCAS market, with an active spot market for FFR. This could be thought of as adding a R1 and L1 service (1 second response time), or similar. This is aligned with the AEMC proposal.
2. As a transitional measure, all FFR providers should be offered a fixed (regulated) price for this service, adjusted annually.

This framework would encourage the development of FFR capabilities (to underpin a future competitive market), and allow AEMO to gain practical experience with an increasing range of technologies and providers. As described above, this should provide substantial value to consumers in the long term, when the availability of these services provides a wider range of low cost options to meet the FOS.

4.2 Fixed price payments

AEMO proposes that a regulated price be paid to all providers of FFR, paid whenever the resource is actively available to provide FFR.

These availability payments would reflect the variable availability of FFR from resources. For example, wind farms are able to provide around 10% of their present operating level in FFR; this varies over time. FFR payments would be scaled to the amount of service available in each interval. Similarly, photovoltaics and demand-side resources may only be available at certain times. Storage technologies would be able to determine in real-time their preference for leaving headroom for FFR provision, or using their full capacity for energy arbitrage and other purposes.

A regulated payment is preferred over a tender for a fixed volume for a number of reasons:

- A tender process could be challenging to define for technologies with variable FFR availability (such as wind and PV), especially when comparing the value of these technologies to storage resources (which can be available when required, but often may prefer to use headroom for other services such that availability will depend upon operating preferences). Fixed payments avoid this challenge, by offering all providers the same price, whenever they are available. Market participants themselves are in the best position to determine their likely operating patterns, and therefore their likely revenue available from FFR services.
- No specific volume target is required in the near-term; rather, the goal of the scheme is to provide a marginal incentive for new market participants to justify installing whatever FFR capabilities are available for their technologies at the time of construction. Fixed payments recognises that FFR at this stage is not intended to substitute for other services, but still provides long-term value to the grid. Technical mandates may also exclude key technologies, such as DER and demand side response.
- A tender process has defined timelines, which may not capture all new entrants. This is appropriate if a certain quantity of service is essential, to be delivered in a certain timeframe. However, the intention of this mechanism is rather to provide an incremental incentive to encourage all new entrants to include FFR capability,

regardless of when they enter the market. This is targeting participants entering the market for other reasons, who can easily include this incremental capability. A tender process could lead to the installation of assets dedicated to FFR, presumably at significantly higher cost to consumers. This is not appropriate, given that FFR services are not essential immediately.

The appropriate fixed prices, scheme durations, and any volume limits would need to be determined through modelling and economic analysis. The availability prices (applied equally to all providers) could be adjusted every year as required, to moderate total costs as the total number of participants grows. This would reduce the risk to consumers of excessive costs or over-procurement of FFR.

AEMO proposes that this approach provides an appropriate balance between certainty for investors, and flexibility for consumers. The fixed price is clearly indicated for the coming year, providing a clear market signal in the short term. Investors would be exposed to some uncertainty regarding potential changes in this price in future years, and the potential transition to a future spot market. However, it is appropriate to allow adjustments to the price on an annual basis, to ensure that the total cost to consumers remains suitable over time. The level of FFR payments could be set at a level that is sufficient to encourage inclusion of the incremental capability, despite some uncertainty regarding future payments.

If multiple FFR services were defined (such as an FFR contingency service, and a fast regulation service), these could each have a defined (regulated) price, calculated based upon the cost for typical providers to include the incremental capability, and deliver that service.

If desired, scalars could be used to adjust the payments to each generator according to their capabilities. For example, faster response could result in higher payments[7]. Alternatively, the impact of the FFR on the frequency nadir could be quantified for a representative contingency event, allowing “fair” comparison of the beneficial impact of power injections of different shapes, from different resources[8]. If appropriate, additional (but small) fixed annual payments could also be applied and varied for new entrants each year, if the underlying costs of including FFR capabilities with those technologies changes significantly over time. These options would adjust the level of risk incurred by participants and by consumers.

This is similar to the transitional FFR approach applied by EirGrid in Ireland, where all capable generators are offered a contract, with regulated prices for each service, paid when the generator is available to provide that service.

4.3 Long term – Spot market for FFR

Eventually, with sufficient experience and a sufficiently large pool of providers in all relevant regions, it would be appropriate for FFR to be procured in the same way as other FCAS. This could be thought of as adding a R1 and L1 service (1 second response time), or similar. This approach is preferred as an aspirational goal for the following reasons:

- It aligns with the existing FCAS market, which is simpler, and appropriate if the existing FCAS market framework is considered suitable.
- It allows real-time co-optimisation of FFR with inertia, and the R6/L6 services, which is essential for efficient market operation in future. In particular, it would allow AEMO

7 This approach is applied in PJM (for dynamic regulation services), and by EirGrid (for contingency FFR).

8 This is proposed by GE in their report to AEMO.

to actively and precisely manage the recovery period for wind inertia-based FFR[9], and the other complex issues related to utilising FFR efficiently in real time.

- It would provide more accurate price signals to providers on the relative value of FFR services in real time, allowing more efficient decisions. For example, storage providers will be able to more accurately determine whether headroom is more efficiently used for FFR or energy delivery, or other competing purposes.

AEMO notes that a market could be started with a relatively low price cap, potentially aligned with the proposed fixed payments, allowing for a smooth transition.

4.4 AEMO procurement

In the AEMC proposal, TNSPs would be responsible for contracting with FFR providers. Under this alternative framework, there would be no need for TNSP involvement. AEMO could manage settlements for FFR directly.

However, under both the AEMC's original proposal and AEMO's inertia proposal, TNSPs could still proactively procure FFR through a RIT-T process, if it was found to be the least cost way to relax constraint equations relating to inertia and meet the inertia system standard. Any FFR that relaxes constraint equations relating to inertia would automatically assist in meeting the inertia system standard, and therefore reduce the inertia requirement. TNSPs could procure FFR beyond the level in the market, if necessary to meet the standard.

4.5 Advantages of this approach

This approach has a number of advantages:

- The fixed price approach is very simple, and provides an immediate, clear, and easily quantified incentive for new entrants.
- This proposed approach would facilitate more certain development of these resources immediately, and allow a more rapid transition to an active spot market.
- This could provide a sufficient incentive to allow removal of the AEMC proposed generator obligations to provide FFR (which are inherently challenging to define, given the different capabilities of each technology).
- This approach is inclusive of demand-side providers and aggregated DER (which would be difficult to capture in generator obligations).
- When FFR is available in sufficient quantities to displace inertia (and as soon as AEMO is confident of its abilities) this can be reflected directly and immediately in any constraints relating to inertia. This will automatically translate into a reduced inertia requirement, by allowing FFR to alleviate inertia-related constraints, assisting in meeting the system standard for inertia.

[9] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/FFR-Coversheet-2017-03-10a.pdf

5. System strength

AEMO has recently provided advice to ESCOSA on the technical standards that should be imposed on new licensed Generators in South Australia, covering a number of issues, including system strength. Whilst that advice is specific to licensing arrangements in South Australia, consultation by ESCOSA is likely to take place in parallel with the AEMC's current consultation and some of the technical subject matter, including system strength, is common to both. AEMO's advice to ESCOSA and subsequent submissions as a result of ESCOSA's consultation should be included in the AEMC's review of relevant material to this consultation.

AEMO considers the framework and allocation of responsibilities set out in section 5.5 of the Directions Paper to be appropriate in principle, particularly given the efficiencies that can be gained by having TNSPs co-ordinate the procurement of inertia with the maintenance of system strength within a specified range. However, successful implementation will critically depend on clear articulation of a policy in the form of accountabilities, powers and mechanisms in the NER. With this in mind, AEMO makes the following comments and suggestions in relation to specific aspects of the proposed framework:

- If a new rule is introduced as described in section 5.5.1 of the Directions Paper, for NSPs to determine the minimum short circuit ratio for each generating system connection point and to register the result with AEMO, there is a question as to whether the registered short circuit ratio should be public information. Transparency of the range of short circuit ratios the NSP is obliged to maintain could be useful to generation investors in making locational decisions, and would also provide a reference for performance reporting purposes.
- Section 5.5.2 of the Directions Paper proposes a new rule be introduced to oblige the NSP to advise a prospective new Generator of the expected minimum system strength at the connection point, and there is provision for the parties to negotiate a higher level of system strength at the Generator's cost if required by the Generator to meet its performance standards. If such a rule is introduced, there may be merit in considering a requirement for some transparency around how the NSP would determine the minimum short circuit ratio and guidelines in the NER to support efficient convergence of the negotiation between those two parties.
- Further to the previous point, the proposed framework does not appear to contemplate setting a minimum short circuit ratio that the NSP should maintain at all connection points across the network. There may be merit in considering what would drive acceptable minimum levels of short circuit ratio, and whether the NER should provide guidance or standards in relation to that.
- Section 5.5.2 of the Directions Paper proposes that "a connecting generator would be required to consider the impact of its generating system on the ability of existing generating systems to meet their generator performance standards". We suggest that it would not be workable to place this obligation on the connecting Generator, as it is unlikely to be in a position to manage impacts on other Generators. Instead, it would be more practical for the NSP to be required to negotiate to connection conditions that maintain the system strength it is obliged to provide at the connection points of existing generating systems. Once finalised, those conditions would be expressed in a connection agreement with the new generator, and registered with AEMO where appropriate. If the connecting Generator is required to fund any support to system strength to "do no harm" to existing generating systems, it would presumably be a one-

off requirement and the NSP would be required to manage system strength as a prescribed service on an ongoing basis. This would need to be made clear and unambiguous in the NER.

- The majority of the framework for system strength set out in the Directions Paper relates to the connection point, with registered values for system strength and generator performance standards all specified for that location. However, section 5.5.4 indicates that the Commission is considering whether to include an obligation in the NER for new inverter-based generation to be capable of operating at a given minimum short circuit ratio. While this option is worthy of consideration, it would be important to consider a broad range of factors before concluding that such a provision would improve efficiency. For example:
  - Some generating systems might have many generating units that are geographically and electrically remote from the connection point while other generating systems might have few generating units close to the connection point.
  - Some central network solutions might have lower overall cost than multiple solutions at multiple individual generating units.
  - Some network locations might have high system strength so the improved generating unit performance might not be necessary.

The above comments and suggestions are offered at a high level at this stage, and AEMO is prepared to continue supporting the AEMC's work as it develops the detail of the system strength management framework.