Inertia Ancillary Service Market Options

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A MarketWise Solutions Report

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Social Responsibility

MarketWise Solutions Pty Ltd are signatories of the Clean Energy Council's Women in Renewables Leaders' Pledge.

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Executive Summary

The Frequency Control Subgroup within the Australian Energy Council (AEC) engaged MarketWise Solutions to explore some options for an inertia ancillary service market to be developed as part of the National Electricity Market (NEM).

The AEC Frequency Control Subgroup has made substantial progress in developing its thoughts in this area and has already developed some options. This consultancy was to support a dialogue with the members of the subgroup, reconcile the diverse thoughts held, identify a set of assessment criteria, and describe the advantages and disadvantages of each option according to the criteria. Based on feedback received from members and MarketWise Solutions' consideration, a recommend preferred market design was developed.

The current regulatory framework only supports the provision of some 'security critical' levels of inertia when an inertia shortfall has already been established. It does not support the valuation of inertia under normal operating conditions. It also does not result in transparent price signals in an operational and investment timeframe.

To overcome the shortcoming of the current regulatory arrangements, the paper considers four inertia market options: a spot market for inertia, an ahead market for inertia, shadow pricing of inertia, and some improvements to existing inertia procurement contract obligations. A set of assessment criteria were developed to help the comparison of the four options.

The option that is most consistent with the current NEM market design principles is the inertia spot market option. In an inertia spot market, inertia dispatch outcomes are consistent with energy market dispatch outcomes, and these can also be co-optimised with, for example, Fast Frequency Response (FFR), Fast Frequency Control Ancillary Services (FCAS). Inertia prices can reflect regional differences if the requirements of the power system differ in some regions. The inertia spot market builds on existing pre-dispatch and dispatch processes to ensure it is effective in real-time and inertia services are made available when needed. The spot market prices reflect the economically efficient price of inertia in an operational timeframe and under various real-time operational conditions. Granular, 5-minute dispatch interval and regional specific prices provide valuable information for potential investors in technology that can provide inertia. The spot market design is technology neutral, transparent, and relatively simple.

Three more options were also considered for pricing inertia.

An ahead or close to real-time market was considered, based on ERM Power's Rule change submission. Under this option, various system security ancillary services may be scheduled ahead of energy. This approach is likely to be complex, and it is inconsistent with current NEM design principles (e.g., self-commitment and emphasis on real-time processes and prices). This approach could also lead to over (or under) provision of inertia, and distortion of price signals in energy and FCAS markets. Importantly, the approach forgoes the benefits from real-time co-optimisation of system security and energy dispatch.

An alternative is to use shadow prices where the value of inertia is determined based on the marginal value of inertia when an additional unit of inertia could relieve an otherwise binding dispatch constraint.

This option appears to undervalue inertia as inertia has a more fundamental role in maintaining secure operation of the power system, even when there are no biding dispatch constraints. This option is also unlikely to be effective in ensuring that the efficient level of inertia is made available when needed.

Modifications were also considered to existing regulatory requirements where transmission companies are required to procure some ‘security critical’ level of inertia. Several variations were considered to the procurement contracts where transmission companies or AEMO enter into agreements with inertia service providers and AEMO calls them into operation when needed. One option considered includes AEMO running quarterly reverse auctions for short-term peak and off-peak inertia service contracts. Due to their ‘out-of-market’ nature, these options replicate some of the shortcomings of the current regulatory arrangements (inefficient, potentially expensive, non-technology neutral).

1. Introduction

AEMO's 2020 Integrated system plan (ISP) projects a future decline in system inertia. Under reduced inertia operation, the frequency nadir following a contingency event is expected to become increasingly deep and reached faster. This increases the likelihood of emergency mechanisms being triggered and the requirements for certain frequency control services. Emergency mechanisms such as the under-frequency load shedding (UFLS) and over-frequency generation shedding (OFGS) may become ineffective if the Rate of Change of Frequency (RoCoF) is too high. Currently, the National Electricity Rules (NER) include an inertia framework that supports the provision of some 'security critical' levels of inertia when an inertia shortfall has been established by AEMO. However, the NER does not support the full valuation of inertia when there is no shortfall. The provisions in the NER also do not extend to inertia beyond the minimum required levels of inertia.

The NER provides a principle that "...market ancillary services should, to the extent that it is efficient, be acquired through competitive market arrangements and as far as practicable determined on a dynamic basis."[1]

The AEMC has developed a 'system services objective' as part of its consultation on the System Services Rule changes: to promote efficient short-run operation and use of, and efficient long-term investment in generation, load, storage, networks, and other system service capability. The AEMC considers that "the design of these frameworks should show explicit regard for how best to facilitate investment in the operation and use of system services over time, and how allocative and productive efficient outcomes in the short run can be maintained into the future. This means developing flexible market and regulatory frameworks, that can adapt to future changes."[2]

This paper first describes the supply-demand characteristics of inertia as a service. It then provides a brief overview of the current regulatory arrangements and discusses its shortcomings. In Sections 4 to 7 various inertia market options are considered, grouped into the following categories:

Option 1. Spot market for inertia

Option 2. Ahead or close to real-time market for inertia

Option 3. Shadow pricing of inertia

Option 4. Procurement contracts

In line with the NER and the AEMC's 'system services objectives', a set of assessment criteria were developed, such as efficiency of price signals at an operational and investment time frame, effectiveness of making inertia available when needed, consistency with market dispatch outcomes, and minimising costs to customers. All four options were assessed using the same set of criteria.

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[1] National Electricity Rules (NER) Clause 3.1.4(6)

[2] AEMC, Consultation Paper - System Services Rule Changes, 2 July 2020, p. 23

2. Overview of inertia as a service

2.1 Overview of inertia services supply-demand characteristics

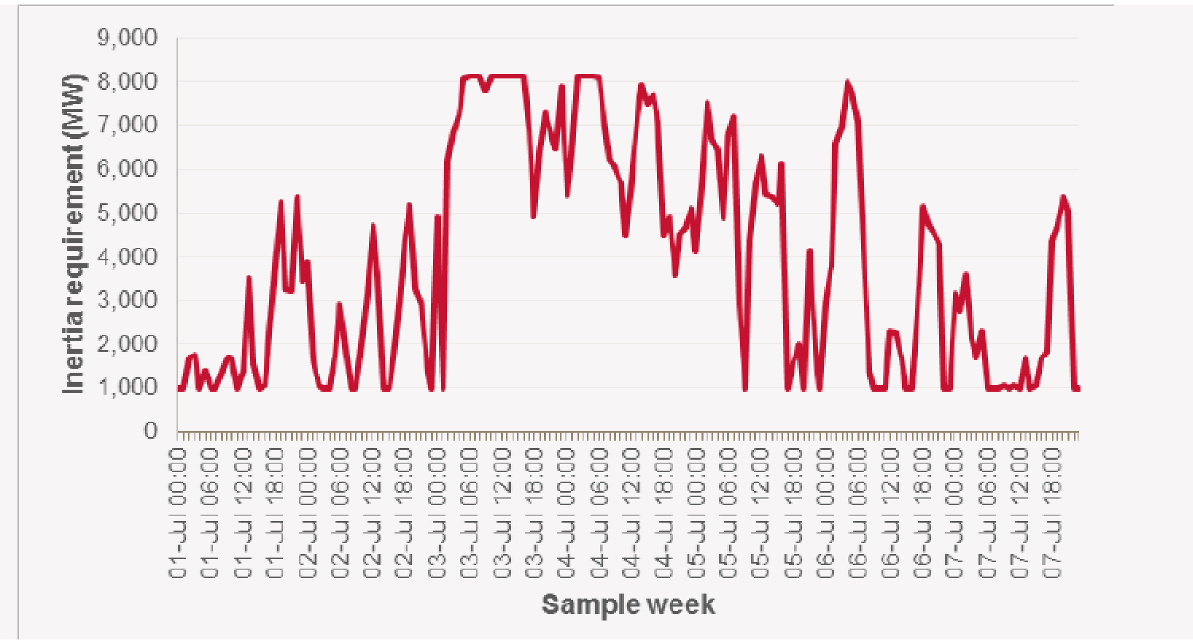
Inertia has a crucial role in maintaining a secure power system. Some of the characteristics of how inertia is provided include the following:

- Inertia from rotational generators has a binary production function; either all or no inertia is provided.
- Some equipment can provide inertia without energy output and some must generate at least at minimum generation (MinGen) level. Some inertia providers (e.g., synchronous condensers, or SynCons) may need to draw load from the grid.
- Other services may also be concurrently provided when inertia is provided, though not all technology that is able to provide inertia can provide these services equally (e.g., system strength, reactive power control capability) and many of these services are local only.
- Up to some minimum threshold level, inertia has currently no substitute; when inertia levels are low, inertia's value in maintaining a secure power system is very high.
- Above this minimum threshold level inertia may be operationally substituted with other services (e.g., FFR and fast FCAS) to achieve essentially the same benefits (e.g., RoCoF control).
- Under normal circumstances and potential separation events, inertia is a NEM-wide service; under islanded conditions, inertia is a region-wide service.

To 'future proof' a market design, it is important to consider how inertia and other competing services are expected to be provided in the future:

- With the changing operational patterns and eventual exit of synchronous generators, rotational inertia is expected to become increasingly scarce; meeting the minimum threshold level of inertia may become more important and more frequently occurring issue than it is today.
- The variability of the need for inertia at an operational timescale is expected to increase. For example, AEMO has demonstrated that in SA the inertia need may increase eight-fold in a matter of hours (see Figure 1 below)
- With evolving technology, inertial response may no longer be binary in all cases; there may be new technology that can provide it at various 'service levels' up to overcurrent limit.
- Synthetic inertia and other forms of service are expected to increase in the future.

Figure 1 Potential variability in inertia requirements in South Australia (assuming 2Hz/s RoCoF limit)[3]



2.2 Inertia and the frequency control ancillary services

Of the various types of frequency control ancillary services (FCAS) inertia is most frequently compared to the fast frequency response (FFR) service. Both inertia and FFR act to *arrest* the frequency. However, inertia and FFR are two distinct services, with different roles and purposes. For example, they are delivered via different physical mechanisms, and play roles that are not always directly interchangeable. Also, inertia plays an important role during normal operating conditions, whereas FFR is only useful during contingency operations.

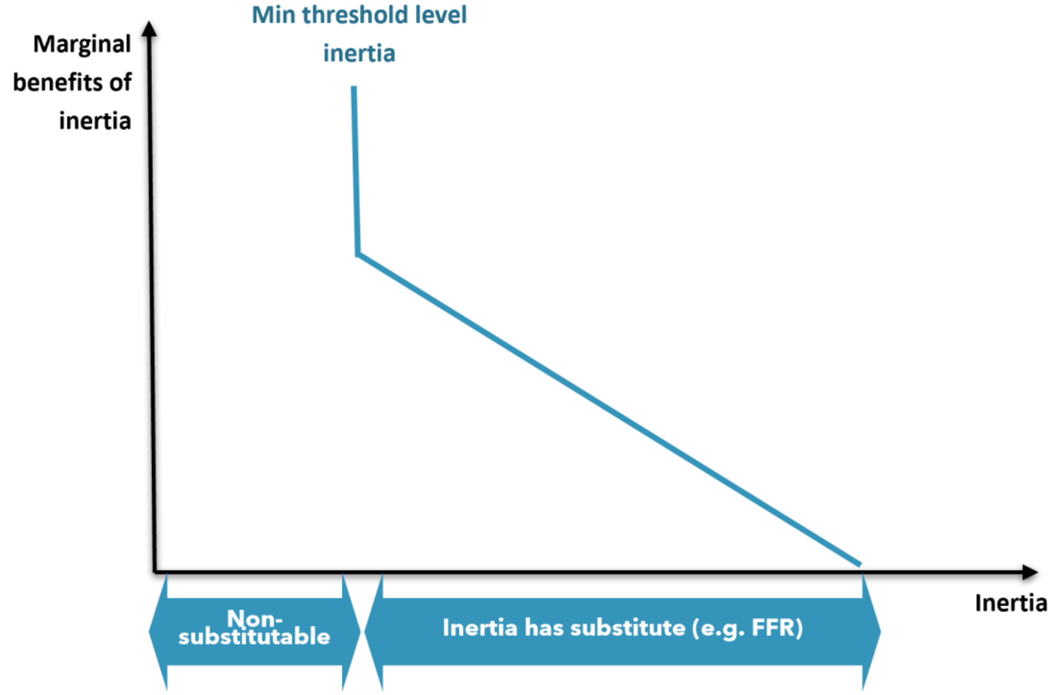
Figure 2 below show that large power systems currently require a minimum threshold level of inertia. Below this minimum threshold level (depicted as blue vertical line in the figure below) inertia has no substitute and FFR cannot be relied upon. Above the minimum threshold level of inertia, additional units of inertia have decreasing marginal benefits. At a sufficiently high level of inertia, there are no additional benefits from additional units of inertia and thus the figure shows that at a certain point the marginal benefit of additional inertia reaches zero.

Inertia and FFR levels are inherently interlinked: the quantity and type of FFR required to arrest frequency excursions and act to return the system to a secure state is related to the amount of inertia that is available. The more inertia that is made available in the system, the more the FFR can be relied upon.

The **system security benefits** of inertia primarily relate to the minimum threshold levels of inertia whereas **market benefits** primarily relate to inertia levels above the minimum threshold level.

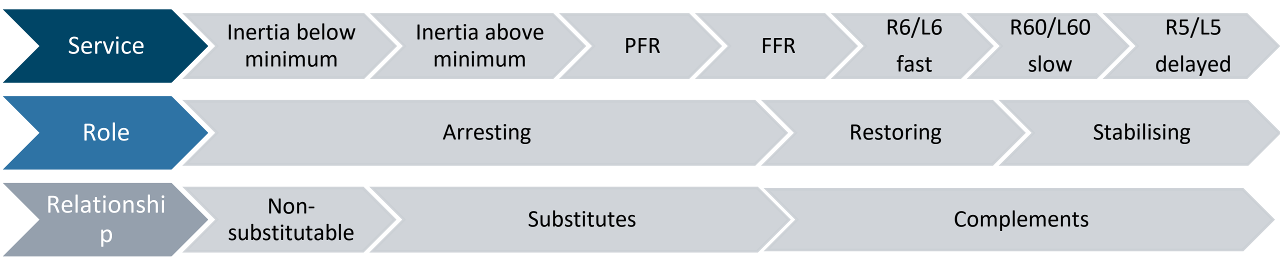
[3] Source: AEMO, Submission to AEMC Directions paper - System security market frameworks review

Figure 2 Substitutability of inertia



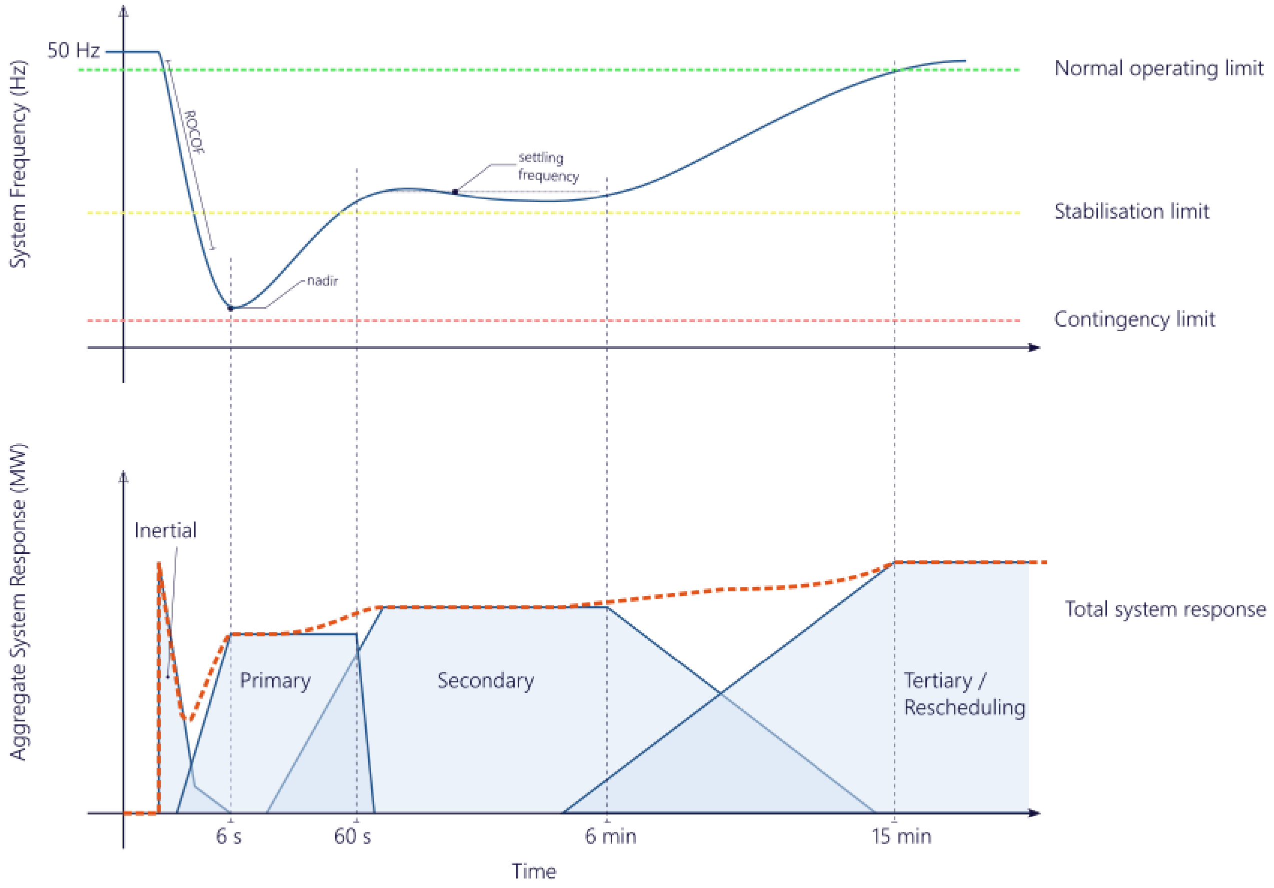
Although depicted as linear, the relationship between inertia and FFR, and how they are best optimised for the purpose of system security and market benefits can be better described by dynamic models that incorporate a range of operational variables, including interactions with other types of FCAS. Using a simplified framework, inertia's relationship with other types of FCAS services may be described as a combination of 'substitutability' and 'complementarity' (see Figure 3).

Figure 3 Inertia's relationship with different frequency control services



This complex relationship is further demonstrated by Figure 4 which shows a stylised sketch of system frequency and typical frequency control ancillary services deployed in the response to a generation contingency event.

Figure 4 Stylised system response to a generation contingency[4]



The system frequency has three key characteristics labelled: RoCoF, nadir and settling frequency in Figure 4. These must be managed to limits (set by a frequency operating standard, or FOS) by adjusting the real power (MW) balance of the system in response to frequency changes. The combined response of all frequency control services is shown in the lower plot. The distinctions between different ancillary services according to the timeframe of their response and system frequency characteristics reflect useful trade-offs that need to be optimised in the total system response.

Given the distinct roles of inertia and other FCAS services, each should be financially rewarded in line with its respective benefits and impacts, and co-optimised when appropriate. Co-optimisation is further discussed in the next section.

[4] AEMO, Contingency Frequency Response in the South West Interconnected System (SWIS), Technical Proposal for the Power System Operation Working Group, July 2019, p.8

2.3 Potential for co-optimisation in the NEMDE

AEMO is required to operate the central dispatch to determine the optimal combination of resources based on offers for the provision of energy and market ancillary services, and subject to physical constraints. The NER sets out several requirements for the dispatch but considering the interactions between inertia, FCAS, and the newly established FFR services is not one of them.

During stakeholder consultation for the FFR Rule change, several stakeholders noted that co-optimisation between inertia, FFR, and other FCAS services would be expected to deliver more efficient market outcomes, with overall lower cost, when compared to current market arrangements.[5]

Given the differentiated treatment (and value) of inertia *below* and *above* the minimum threshold level, the following discussion makes a distinction between what may be included in co-optimisation below and above the minimum threshold level.

Co-optimisation *below* minimum threshold inertia

Regarding system security benefits, some of the potential gains from optimisation relates to ensuring that AEMO keeps the minimum threshold level of inertia as low as necessary (but not lower) to achieve the system security benefits.

Figure 5 below shows that AEMO already differentiates inertia requirements under at least three types of system conditions: normal operating state, credible risk of islanding, and islanded.[6] Within the normal operating state, however, the inertia requirements are static, they are not dynamically aligned with the changing operational characteristics of the power system.

Figure 5 Relationship between system condition and inertia levels

[5] See submissions by ERM Power, CS Energy and Tilt to AEMC's Directions paper – Frequency control rule changes

[6] AEMO, 2020 System Strength and Inertia Report, December 2020

A static minimum threshold inertia requirement is likely to create inefficiencies. For example, if this minimum level of inertia is set above the true minimum threshold, this may leave less 'room' for trade-offs between inertia and FFR, and this could distort the market of substitute ancillary services.[7]

As noted above, inertia can be used in lieu of FFR *above* the minimum threshold level. However, FFR cannot be used in lieu of inertia *below* the minimum threshold level. Establishing the minimum threshold inertia dynamically ensures that it is aligned to changing operational characteristics (e.g., the size of maximum contingency and protected events, level of operational demand). When the minimum threshold inertia requirements are dynamically set, the costs of meeting system security can be minimised and the benefits of co-optimising inertia with other services above the minimum threshold level can be maximised.

Co-optimisation *above* minimum threshold inertia

Above the minimum threshold level of inertia, co-optimisation could ensure that the trade-offs that are possible between inertia, FFR and other FCAS services do occur, and these are reflected in prices and financial payments.

AEMO in its submission to the FFR Rule change considers that co-optimisation of FFR and inertia is theoretically possible though it would increase the complexity of dispatch.[8] Various options for co-optimisation were discussed in AEMO's FFR Implementation Options paper.[9] AEMO modelled the relationship between inertia, FFR and R6 under certain system conditions and the modelling confirmed that increased levels of inertia were associated with lower levels of FFR and R6 requirements. As a result, AEMO incorporated the consideration of inertia levels in setting the R6 requirements.

Above the minimum threshold level of inertia, a key benefit of inertia relates the cost savings from reduced requirements for FFR and fast FCAS.[10] The opposite is also true: the more abundant and low costs are FFR and fast FCAS services, the more cost savings there may be from reduced levels of inertia requirements. However, the co-optimisation of FCAS and energy in the NEM Dispatch Engine (NEMDE) currently does not include the consideration of FCAS costs in determining the various FCAS dispatch requirements. Instead, FCAS requirements are static and are varied only under certain circumstances,

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[7] The current inertia procurement framework does not allow the substitution of inertia with FFR below the minimum threshold level of inertia. AEMO in its submission to the FFR Rule change also made it its views explicit that such trade-offs should be reserved for inertia above the minimum threshold levels. However, to achieve the secure operation of islanded regions and also possible separation events, AEMO considers that FFR could reduce the need for inertia. (See Section 3.1 for more details on current regulatory framework).

[8] As part of its Frequency control work plan published in September 2020, AEMO has indicated that it intends to implement dynamic constraints for contingency FCAS volumes in Q3/Q4 2021. These new constraints are intended to recognise the link between R6 requirement and the level of inertia for system intact operation of the NEM (excl TAS). Most likely AEMO's recognition will be 'one directional' in that it will adjust FCAS requirements in line with inertia 'availability' but it will not adjust inertia requirements when, for example, FCAS costs are high.

[9] AEMO, Fast Frequency Response Implementation Options - Technical advice on the development of FFR arrangements in the NEM, April 2021

[10] For example, the AEMC notes that when system inertia is 55,000 MWs the dispatch of 164 MW of FFR is expected to result in a reduction in R6 requirement equivalent to an approximately 14,500 MWs of additional inertia (equivalent to 6 to 9 large thermal units). However, this does not mean that the 164 MW of FFR should then be dispatched. Instead, given the costs of inertia, FFR, and fast FCAS the system is required to identify the optimal 'balance' of service provision that minimises the costs while not compromising service outcomes. This demonstrates that pricing inertia is just as important for FFR and fast FCAS as it is for inertia providers. In absence of inertia prices, it is 'freely available' and will distort the quantity and prices in FFR and fast FCAS markets.

but not with costs of FCAS services.[11] This approach appears to have significant 'inertia' (excuse the pun!) as the most recent FFR Rule change contains no requirements for the newly established FFR to be optimally dispatched nor to be dynamically set by AEMO.

In summary, the role of co-optimisation above the minimum threshold level of inertia could be to reduce the overall cost of system services.

[11] There are circumstances when constraints may apply in which the volume of local FCAS and the flow on the interconnector are in one LHS constraint. This then co-optimises energy dispatch with FCAS volume. However, this co-optimisation does not vary, for example, the FCAS volume according to FCAS costs.

3. Current regulatory requirements

3.1 TNSPs' obligation to procure and continuously make available minimum required inertia

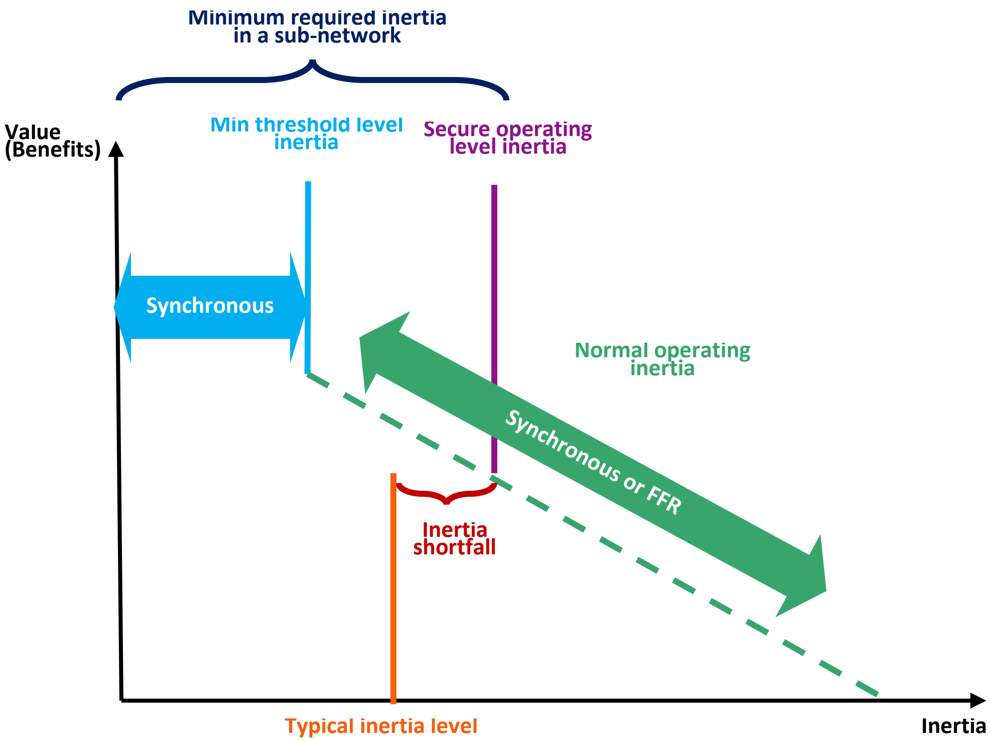
Since 2018, AEMO has the obligation to determine the **minimum required inertia** in each of the sub-networks (regions) in the NEM. Depending on whether the objective is to operate a sub-network in a satisfactory or secure operating state, the minimum required inertia may be set as

- the **minimum threshold level** of inertia, being the level of inertia required to operate the sub-network in a satisfactory operating state when it is islanded, or
- the **secure operating level of inertia** (SOLI), being the level of inertia required to operate the sub-network in a secure operating state when it is islanded.

To determine these levels, AEMO adopted an approach to calculate the secure operating level of inertia as the minimum threshold level of inertia plus the inertia of the largest generating unit providing inertia within a sub-network.

AEMO is also required to establish whether an inertia shortfall exists in any of the sub-networks. The **inertia shortfall** is assessed as the difference between the secure operating level of inertia and the **typical inertia level** in each of the sub-networks (i.e., the typical levels of inertia available under typical patterns of dispatch). Figure 6 below depicts how these inertia concepts relate to each other.

Figure 6 Inertia levels relevant for current regulatory procurement obligation



Where there is an inertia shortfall in a sub-network, the relevant Transmission Network Service Provider (TNSP) must address the shortfall by making continuously available the minimum required inertia. The NER further prescribe that the inertia that TNSPs must make available must be synchronous inertia. More specifically:

- the minimum threshold level of inertia must be met through synchronous inertia, and
- the secure operating level of inertia may be met through a combination of synchronous inertia and inertia support activities (e.g., FFR services), but inertia support activities may only be used in lieu of synchronous inertia with AEMO's approval.[12]

Importantly, the obligation on TNSPs is to make the full **minimum required inertia** continuously available, and not just the amount of the shortfall. This is because any contracts that the TNSPs have with synchronous generators to come online to provide inertia are likely to cause other synchronous generators, which are also providing inertia, to be pushed out of the dispatch merit order, potentially resulting in only a small, or no, overall increase in inertia.

This requires TNSPs to contract at levels above the **minimum required inertia** to make sure that the required level can be met at any given time.

When inertia is needed, AEMO may enable inertia services up to the

- the minimum threshold level of inertia where an event has been classified as a credible contingency event or a protected event, and
- the secure operating level of inertia where the sub-network is islanded.

TNSPs are required to seek and identify the least-cost (combination of) option(s), and these may include either:

- directly investing in synchronous condensers (SynCons);
- entering into inertia services agreements to provide the services by means of a synchronous generating unit or SynCon; or
- any other types of complementary inertia network services (e.g., FFR) provided by the TNSP or a third party through contracting.

[12] The NER currently prescribes the use of "synchronous" inertia but as technology matures this term will likely need revision.

3.2 Assessment of current regulatory arrangements

There are several concerns with the current requirements. These are summarised in the table below grouped into different assessment categories.

Table 1 Assessment of current regulatory requirements for TNSPs to procure and continuously make available minimum required inertia

Criteria	Current regulatory requirements for TNSPs to procure and continuously make available minimum required inertia
Efficient level procured	No. The arrangements to do not result in the efficient level of inertia being procured. First, the obligation to make the minimum required inertia continuously available results in TNSPs contracting at levels above the minimum required level to make sure that the required inertia can be met at any given time. Second, TNSPs contracts sit outside the dispatch processes. When AEMO instructs inertia providers to come online (in line with their contractual obligations with TNSPs), they are likely to cause other synchronous generators, which are also providing inertia, to be pushed out of the dispatch merit order. This may result in only a small, or no, overall increase in inertia.
Outcomes consistent with market dispatch and are co-optimised with FFR and other system services	No. The procurement outcome is disjoint from market dispatch. Decisions are made at different timescale and sequentially. Market participants that contemplate being party to an inertia contract with TNSPs must make assessments ahead of time and in absence of knowing the dispatch outcomes. Regarding co-optimisation, although there are provisions in the NER for trade-off with inertia support services (e.g., FFR), the co-optimisation (if any) can only take place at the time of contracting. This may be every 2-3 years. The assessment of the trade-offs between inertia and inertia support services is 'static' and is subject to AEMO's approval.[13]
Effective in real-time, ensures inertia service is available when needed	Yes. However, achieving this requires additional assessments and processes to be established by AEMO to operationalise the decision to call on the inertia services contracts. The outcome of AEMO's decision is then included in manual dispatch instructions issued via the market systems. Inertia service providers are also required to establish additional processes to respond to calls by AEMO in line with their contractual obligations. These processes are disjoint from, and may be at odds with, service providers' participation in the energy spot market.
Efficient price signal of the value of inertia in an operational timeframe under different power system conditions	No. The regulatory requirements do not provide an ongoing price signal of the value of inertia at an operational timeframe. It does not reward inertia service providers for the benefit they provide during the normal operation of the power system when no inertia shortfall has been identified. There is no adjustment mechanism included in the regulatory arrangements, such as dynamic pricing that would reflect the power system's inertia requirements (demand) and the availability of inertia services (supply).
Efficient investment signal	There is a lack of investment signal for potential inertia service providers and for those who invest in inertia R&D and technology. First, AEMO must predict an inertia shortfall before procurement by TNSPs is required. Second, neither the

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[13] In its submission AEMO notes that "…AEMO is currently reviewing how FFR is used under islanded conditions and at times of credible islanding risk." For further details, see AEMO, Submission to the AEMC's Consultation Paper – System Services Rule Changes, 13 August 2020, p. 19.

	level of contracting nor the prices agreed by TNSPs, and service providers are publicly available. Therefore, potential investors lack information required to assess the commercial viability of providing inertia services. This may be particularly acute problem given that inertia capabilities are inherently linked to the engineering design of the units and these designs are prepared several years in advance.
Risks allocated to those best able to manage them, avoids single view dominating decisions	Inertia requirements are assessed by AEMO on an annual basis, using 'typical dispatch' levels which may not accurately reflect the need for inertia. For example, the need for inertia may be infrequent but severe. Also, Figure 1 shows that inertia requirements in a sub-network can change eight-fold in a matter of hours and thus 'typical' inertia requirements are difficult to define. AEMO is tasked to estimate inertia requirements, but it bears no financial consequences for over-or under-estimating the inertia needs. Costs are borne by TNSPs and, ultimately, my customers.
Minimise overall costs to consumers	Costs are not minimised. There is an explicit recognition that when AEMO enables the inertia services in dispatch, these service providers are likely to displace other service providers in the merit order, some of which could have provided inertia at lower costs. There are several costs components of the current regulatory arrangements, including: • the TNSPs' contract cost of inertia (this is the cost of making inertia available on a continuous 'standby' basis); • the cost incurred by inertia service providers to become and remain available, ready to provide inertia at any time, in line with their contractual obligations; and • the cost impact on other service providers who are displaced in the merit order but could have provided inertia at lower costs. Costs incurred by TNSPs are recovered from customers through network charges. The remainder of the costs are borne by other market participants, including generators and inertia service providers.
Technology neutral	The NER prescribes that inertia up to the minimum threshold inertia level must be provided by synchronous generators. Above this level, the service may be provided by inertia support service providers, but this is subject to AEMO's approval. This treatment by the NER may stifle innovation and development.
Simple and transparent	The contracts are not made public and thus they are not transparent. Given the complexities involved in providing inertia services and the myriads of power system events that may impact on parties' ability to comply with the contracts, it is unlikely to be a simple, uncomplicated contract between TNSPs and inertia providers.
Consistency with NEM design principles	No. The NER market design principles[14] require competitive market arrangements and dynamic determinations to be used when practical. When not practical, competitive commercial contracts are preferred over bilateral negotiations. The current regulatory arrangements require TNSPs to negotiate bilaterally.

[14] See NER 3.1.4.

4. Option 1: Spot market for inertia

This Section describes how an inertia market may be implemented in the NEM. The design aims to strike a balance between an economically efficient and a practical solution. The purpose is to illustrate how an inertia spot market may operate, and to provide a starting point for further discussions and refinements.

In Section 4.1 four market design principles that underpin the inertia spot market are established and discussed. In Section 4.2, a step-by-step guide to the potential inertia spot market is provided. Section 4.3 contains an assessment of the inertia spot market, whereas Section 4.4 includes some issues for further consideration.

4.1 Market design principles

Based on the characterisation provided in Section 2, four market design principles were established to guide the development of a suitable spot market design. These market design principles are discussed below.

Design Principle 1: Physical and market inertia levels can be different

Initial units of inertia have very high value. Inertia has a decreasing marginal benefit: as the level of inertia increases the additional benefits from additional units of inertia decreases. The additional benefit approximates zero but does not turn negative. That is, there are no negative externalities for the power system from inertia being provided above dispatched levels. However, there could be negative impacts or distortions in the ancillary markets if inertia is financially rewarded when cheaper alternatives are available (e.g., FFR or fast FCAS).

Design principle 1

- **The "physical" and "market" inertia levels can be different.**
- **The minimum inertia requirements of the system must be met by "physical" inertia. Physical inertia provision need not be limited to the minimum requirements.**
- **Only the 'valuable' level of inertia is paid for. Inertia above the "market" requirements is not financially rewarded.**

Design Principle 2: Energy and inertia can be 'asymmetrically unbundled'

Inertia may be supplied jointly with or without energy. Energy supply must meet energy demand (S = D). However, inertia supply can be more than inertia demand (S ≥ D).

If inertia is 'dispatched' as a result of a binding inertia constraint, the energy that is supplied to provide the inertia (if any) must also be included in dispatch. But not the other way around.

Design principle 2

- **Energy and inertia can be 'asymmetrically unbundled'.**
- **When energy is dispatched, inertia may or may not be considered 'dispatched'.**
- **When inertia is dispatched, energy supplied together with inertia (if any) must be dispatched.**

Design Principle 3: Inertia prices must be consistent with central dispatch, they must reflect inertia supply-demand and power system conditions

The system must maximise the value from the trade of energy while meeting power system security needs and concurrently minimising system costs. In establishing an inertia price, a range of factors must be considered, including:

- the energy constraints (keeping the energy supply-demand in balance)
- the inertia requirements constraints (meeting the minimum inertia levels in each region and NEM-wide), including the consideration of RoCoF control
- co-optimisation with other frequency control ancillary services, and
- the operating state and condition of the power system (e.g., considering whether there is a credible risk of islanding or whether the system has already islanded).

An outcome of the above considerations is that there may be multiple prices in a given dispatch interval. For example, there may be a global (NEM-wide) inertia price under normal operating conditions and there may be several local (sub-network level) inertia prices when there is islanding. The local inertia price (under islanded conditions) is likely to be equal or higher than the global inertia price. An exception may be when the islanded sub-network has high levels of inertia and thus the local inertia price may be lower than the global inertia price.

Design principle 3

- **Inertia prices must be consistent with central dispatch.**
- **Inertia prices must reflect inertia supply and demand conditions, and the dynamic nature of the power system.**
- **When inertia can be substituted by an alternative service (e.g., by FFR above the minimum level) the price paid for the substitute service must be considered in establishing the price of inertia, and vice versa.**

Design Principle 4: Inertia market to be consistent with current NEM design

The current NEM spot market is a physical market where bids and dispatch have consequences for the physical operation of the generation, load and network services units.

Currently in the energy spot market the pre-dispatch and dispatch processes play a central role and MPs have commercial freedom to decide how they will operate in the market. Dispatch decisions are made in 5-minute increments. Pre-dispatch processes facilitate price discovery and the market operator being able to signal to market participants the need for energy and ancillary services. A range of processes are available to facilitate 'slow start' and 'fast start' generators to come online.

To the extent possible and desirable, an inertia ancillary service spot market needs to 'fit in' within existing processes. It must be designed in a way to preserve the principles that underpin the current energy spot market.

Design principle 4

- **Energy spot market arrangements remain the same as currently.**
- **Inertia bids are physical bids, units dispatched for inertia must provide the inertia.**
- **Dispatch is through NEMDE.**
- **Pre-dispatch and dispatch processes play a central role in inertia dispatch.**
- **MPs must consider the costs of operating their units. It is the MPs responsibility to bid consistent with the technical capabilities of their units and their commercial interests.**

4.2 Description of the inertia spot market

Step 1: Register 'inertia services units' and record relevant standing data

As part of its existing dispatchable unit registration process, AEMO would register units that can provide inertia as 'inertia services units'. Relevant technical capabilities such as the inertia constant (MWs/MVA) of each unit and the minimum generation level associated with providing inertia would be recorded.

Step 2: Enable inertia service bids

For units that are registered as inertia service units, the first price band is associated with the unit's inertia capabilities. Therefore, submitting the first energy band automatically also includes the provision of inertia as part of that offer. The inertia need not be included in the offer as it is a standing data, established through the registration process in Step 1.[15]

There could be three types of service providers with the following types of bids:

[15] See discussions in Section 4.4. about options for enabling various energy-inertia levels.

- **(1) Energy-only:** the service provider is not able to provide inertia and thus its standing data is associated with zero inertia (0 MWs). Offers of this kind will continue to be treated as they are currently.
- **(2) Inertia and energy:** the service provider is only able to provide inertia when generating at some minimum level and thus it includes a positive energy level in its first band.[16] When being dispatched at this level or higher, the unit would be obliged to provide inertia. Offers of this kind will be included in consideration for both energy and inertia dispatch.
- **(3) Inertia-only:** the service provider is able and willing to provide inertia without energy output and thus it may include zero energy (0 MW) in the first band, indicating its willingness to operate in SynCon mode if it is only dispatched at that level.[17] Offers of this kind will be included in consideration for inertia dispatch. An important departure from the current formulation of dispatch offers is that when zero energy is included in the first band, the price nominated in that band may be higher than the price associated with the second band. Note that given that there is zero energy included in the offer, it cannot set the price in the energy spot market. When this unit is dispatched at any level (including at zero energy level specified in the first energy band), it will have an obligation to provide inertia.[18]

Rules relating to placing bids in energy bands 2 to 10 remain unchanged.

Step 3: Submit inertia bids and revise bids

MPs submit their bids using up to ten energy bands, as they do currently. The first band is associated with inertia (if any). There is no need to indicate inertia level provided as this is 'hard coded'.

When there is zero energy included in the first band, the price in the first energy band may be higher than the price associated with the second energy band. MPs do not need to identify a price for inertia separate from energy. Each band is associated with a price and an inertia-energy combination.

Bidders are able to revise their prices in line with the NER. Bidding (and re-bidding) rules remain substantially the same as they apply currently under 5-minute settlement.

Step 4: Forecast local and global inertia requirements

Inertia requirements consist of two components:

- **nondiscretionary level** – this varies with the operational state of the power system and may be set at the 'NEM-wide safety net' level (under normal operating conditions), the minimum

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[16] To prevent some undesirable market outcomes or the potential for some market participants to take advantage of some inertia constrains so to gain competitive advantage in the energy market, the MW included in the first energy band would be fixed at the minimum generation level. This, however, does not prevent the generator to submit another bid for additional MW at essentially the same (or slightly higher) price. See also Section 4.4 for further discussion.

[17] Alternatively, SynCons may use an energy band 0 (instead of band 1) so there remains an additional 10 energy band to express their energy supply schedule. The model can also be extended to include different levels of inertia at zero energy levels by the same service provider (e.g., a storage provider).

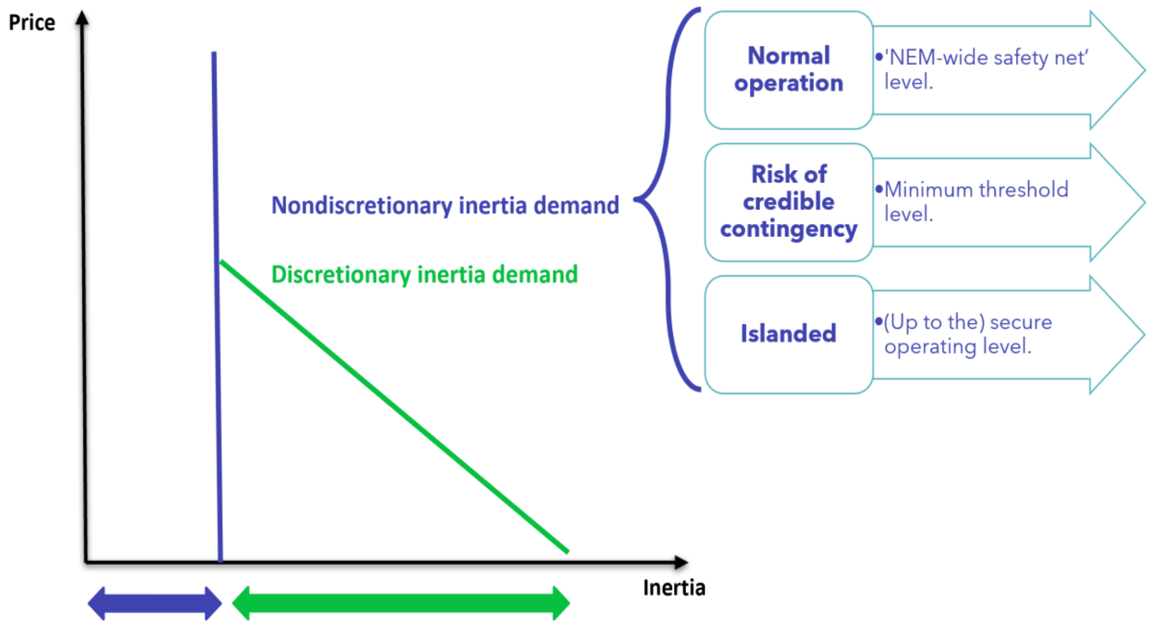
[18] Since the unbundling of FCAS services, FCAS may be provided without providing energy. In fact, it may be provided by loads. In the NEMDE, AEMO represents this as an FCAS service offer at zero energy levels (a vertical line at zero energy dispatch levels). Inertia provided by SynCons can be represented the same way. Syncons can continue to be included in dispatch as a generation unit with zero energy levels and its energy consumption settled as a separate energy transaction.

threshold level (when there is a risk of islanding) or at the minimum secure operating level (when the system has islanded).

- **discretionary level** – this depends on the cost of alternatives, such FFR and fast FCAS.

AEMO would be required to forecast for each dispatch interval and for each region the nondiscretionary inertia requirements that are to be met.

Figure 7 Nondiscretionary and discretionary inertia demand



Forecast of local and global inertia requirements would be in line with current practice described in AEMO's Inertia Requirements Methodology. However, instead of a static, annual assessment, the inertia requirements would be dynamically updated in order to keep these aligned with the real-time needs of the power system

Step 5: Establish local and global inertia supply schedules

In each dispatch interval in each region, the market operator would compute the inertia supply schedule consisting of the (static) inertia values (in MWs) associated with the offers of the inertia service units and the prices at which the service providers are willing to make the inertia available.

- For generators that included zero MW in their first energy band, the price associated with the inertia is simply the price included in the energy band.
- For generators that bid a positive amount of MW in their energy band, the price is the energy included in the first energy band multiplied by the bid price. The product of MW and price represents the minimum payment required by the service provider to make the inertia available.

Table 2 below contains a worked example of how the cost per unit of inertia (MWs) may be calculated based on the offers submitted by inertia service providers.

Table 2 Example of how cost per MWs may be calculated based on offers submitted by MPs in their first energy band

	Example	Energy (MW) in band 1	Inertia (MWs)	Offer price included in bid[19]	Cost if bid accepted (5 min dispatch)	Cost per MWs
MP1	Generator	100	500	$120/MWh	100 x $120/12 = $1000	$2
MP2	Battery storage	50	0	$480/MWh	50 x $480/12 = $2000	N/A
MP3	SynCon	0	1200	$6000	$6000	$5
MP4	Gen in SynCon mode	0	800	$800	$800	$1
MP5	Wind generator	80	0	$360/MWh	80 x $360/12 = $2400	N/A
MP6	Generator	90	1485	$132/MWh	90 x $132/12 = $990	$1.5

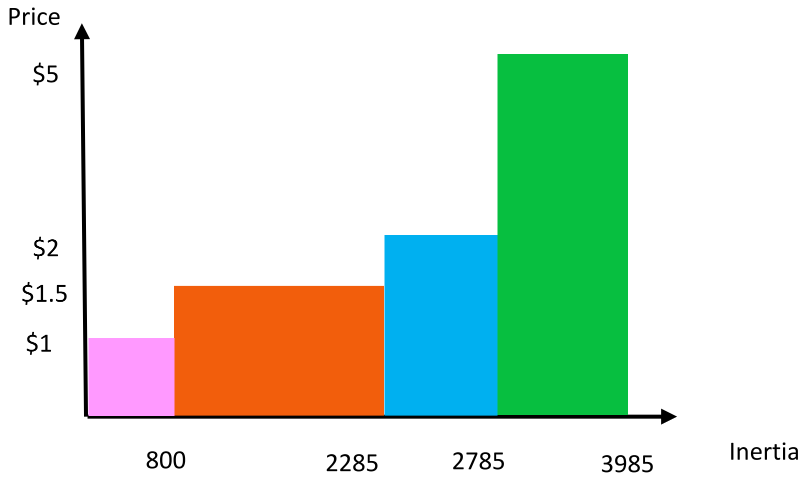
From this list the inertia service supply curve in each region and for the NEM may be constructed. This is the MWs offered by each service provider, ranked from the lowest to highest per unit offers (see Table 3).

Table 3 Inertia service providers from lowest to highest $/MWs offers

	Example	Inertia (MWs)	Cumulative inertia	Total cost if bid accepted (5 min dispatch)	Cost per MWs
MP4	Gen in SynCon mode	800	800	$800	$1
MP6	Generator	1485	2285	90 x $132/12 = $990	$1.5
MP1	Generator	500	2785	100 x $120/12 = $1000	$2
MP3	SynCon	1200	3985	$6000	$5

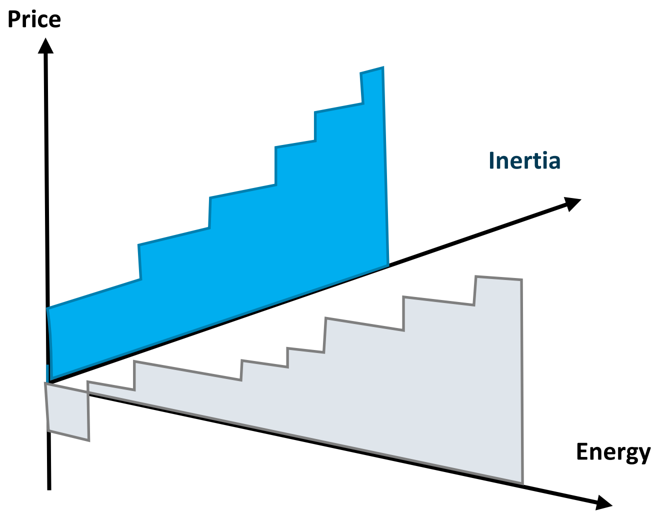
[19] Offer price included in bid is taken to be 'per MWh' when energy level included in the energy band is greater than zero and it is considered a fixed price offer when energy level included in energy band is zero.

Figure 8 Inertia supply curve - inertia service providers from lowest to highest $/MWs offers



It is challenging to represent these joint energy-inertia bids but one way to demonstrate their treatment in this proposed model is to consider them along two different (energy and inertia) dimensions (see Figure 9).

Figure 9 Joint energy-inertia bids represented as separate supply curves



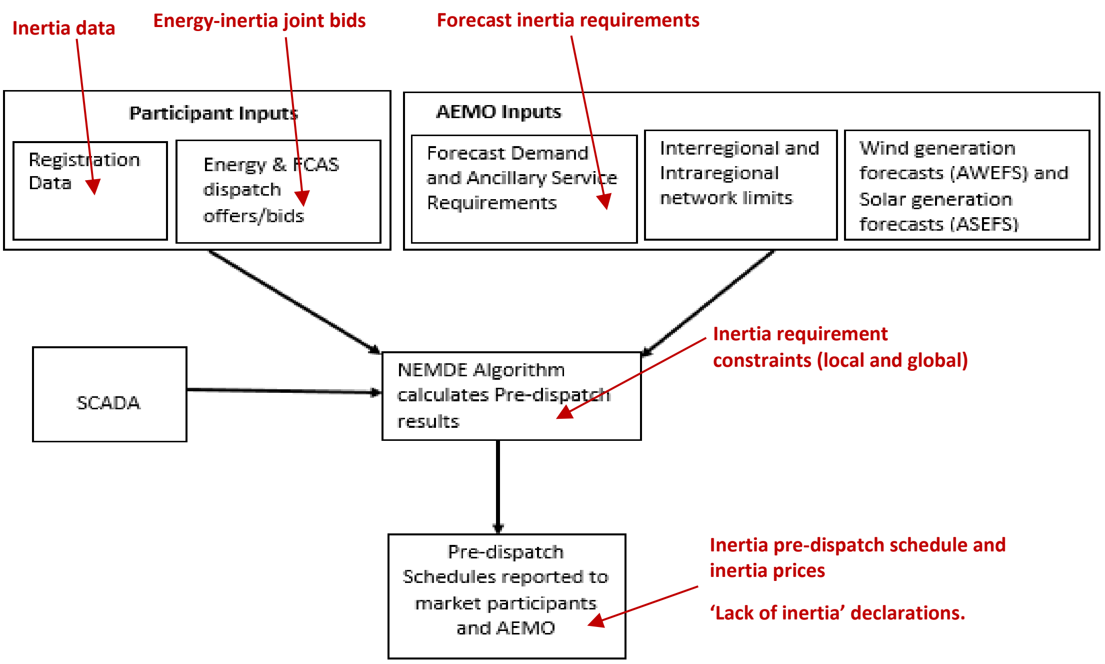
Step 6: Pre-dispatch

Like currently, for each dispatch interval and for each region, AEMO would forecast the dispatch of inertia, FCAS (incl FFR) and energy. Figure 10 below contains an indication of the type of information that AEMO would likely need to include into its pre-dispatch process.[20] For example, AEMO would need to forecast inertia demand according to power system conditions (e.g., NEM-wide, minimum threshold or secure operating state inertia requirements). AEMO would also be required to forecast inertia prices. Similarly to the existing 'lack of reserve' declarations, AEMO could establish different levels of 'lack of inertia' (LOI) declaration, such as LOI1, LOI2, and LOI3.

Also, similarly to current dispatch processes, the units' different start-up times can be accommodated, for example by:

- enabling inertia bids at the inertia floor price when "slow start" generators come online, and
- enabling the use of fast-start inflexibility profile (FSIP) when "fast start" generator comes on line.

Figure 10 AEMO's pre-dispatch process modification as a result of introduction of inertia spot market



Step 5: Dispatch

The dispatch engine is designed to maximise the value of trade while meeting energy and power system security needs. This is achieved by maximising the value of dispatched load less the cost of energy, market ancillary services, and network services.

From a market design point of view, there are two key issues to be determined in inertia dispatch. These are commonly referred to as the issue of

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[20] AEMO, Pre-dispatch, System Operating Procedure, SO_OP_3704, 14 November 2016

- **"winner determination"** – which units receive revenue for inertia in each dispatch interval?
- **"price determination"** – how much do the winners get paid?

Let us first consider the treatment of nondiscretionary inertia and then turn to the treatment of discretionary inertia in dispatch. While these are described in sequence, the dispatch engine would consider the decisions jointly.

Nondiscretionary inertia

As discussed above, a minimum level of inertia is required in the power system. This minimum level varies with the operating state of the power system. There are no adverse system security consequences from additional inertia above the nondiscretionary level though there are no additional system security benefits either from these additional inertia units. (System security here is understood narrowly, i.e., in relation to achieving a satisfactory or secure operating state, should there be a need.)

This characteristic of inertia enables the minimum required inertia to be treated as the *lower limit* (rather than the target or absolute value) of inertia to be dispatched. Therefore, NEMDE would include a constraint to meet *at least* the nondiscretionary levels of inertia while concurrently meeting the energy and other system security needs of the system.

This characterisation is also helpful as inertia and energy production are inherently interlinked and capping the provision of inertia would have significant impact on energy dispatch outcomes. This is avoided by allowing some additional 'unvalued' inertia to be provided as a 'by-product' while meeting the requirements for nondiscretionary inertia. See market design principle 1 above.

Furthermore, this approach also avoids the inertia market to become entangled in a 'unit commitment issue': those not being enabled for paid nondiscretionary inertia may continue to provide energy (and unvalued inertia) in line with their energy dispatch instructions. This is in line with market design principle 4.

Another useful characterisation is that the provision of inertia is treated as independent from energy production, but energy is not treated as independent of inertia production. Energy supplied must meet energy need. This is not true for inertia. Inertia supplied may be more than inertia needed. See market design principle 2.

- When the first energy price band includes positive levels of energy and inertia, the market participant may be dispatched for either energy only, or for both energy and inertia. It will not be dispatched for inertia only, as the market participant could not comply with such dispatch instructions.
- When the energy price band includes zero levels of energy (e.g., a SynCon or a generator in SynCon mode), and this is the level at which the unit is dispatched, then only inertia is required to be provided.[21]

[21] Thought these characterisations may seem unusual in a market environment, they mimic implicit assumptions in the current market settings. Given that the current market is already operating under these simplified assumptions, there are no risks in making these more explicit in the market design.

The levels of inertia that would be used to set the dispatch and price of nondiscretionary inertia is displayed in Figure 7 above.

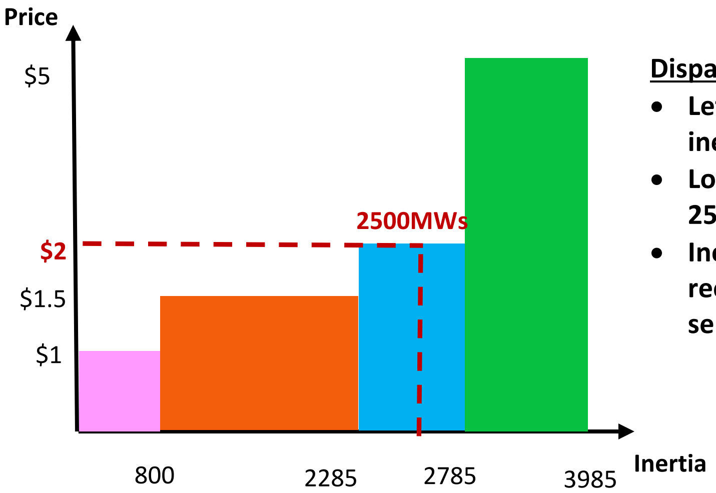
Under normal operating conditions, there may be a single inertia price ($/MWs) across the whole of NEM. When there is a credible contingency event, a part of the inertia is required to be met from local supply. As a result, the inertia price in one or more regions may be higher. This may have implications for the prices in other regions as well: prices in regions with sufficient inertia supply may decrease whereas in regions where there is lack of supply, prices may increase.

For example, let us assume that the inertia offers in VIC in a given dispatch interval are as listed in Table 3 below. Let us assume that AEMO establishes that there is a credible contingency of islanding. Some of the inertia must be met from regional (VIC) supply, let us consider that this is 2500MWs. See Table 4 and Figure 11 for an explanation of how the regional price may be set.

Table 4 Inertia service providers from lowest to highest $/MWs offers

	Inertia (MWs)	Cumulative inertia	Cost if bid accepted (5 min dispatch)	Cost per MWs	Inertia payment
MP4	800	800	$800	$1	800 x $2 = $1600
MP6	1485	2285	90 x $132/12 = $990	$1.5	1485 x $2 = $2970
MP1	500	2785	100 x $120/12 = $1000	$2	215 x $2 = $430
MP3	1200	3985	$6000	$5	$0

Figure 11 Inertia supply curve and dispatch



Dispatch outcome

- **Let us assume that the required level of inertia is 2500MWs.**
- **Lowest cost inertia providers up to 2500MWs are deemed 'dispatched'**
- **Inertia providers up to $2500MWs receive the bid price of the marginal service provider.**

Nondiscretionary inertia - Price and winner determination

Similarly to energy, it is proposed that the per unit price of the marginal inertia service provider needed to meet the minimum required inertia level would be paid to all successful nondiscretionary inertia providers in a given dispatch interval. In the example above it is assumed that the marginal inertia provider may be only partially dispatched for inertia. (Note, that this is a "market" dispatch only, the physical provision of inertia may be higher, see market design principle 1.) This treatment is proposed as the NEMDE is a linear optimisation engine. For service providers that also receive revenue for their energy output, this is unlikely to cause a significant concern.[22] (Note, that in line with market design principle 2, if some level of energy is included in the inertia bid and the inertia is required to meet nondiscretionary demand, the energy component of the offer will also be dispatched.)

Discretionary inertia

Let us consider now the 'discretionary' level of inertia. The benefits from these additional inertia units are primarily 'market benefits'. Currently AEMO does not consider the market benefits that inertia may provide in its dispatch. Market benefits may relate to multiple domains such as relieving constraints that have been invoked across interconnectors, or reducing the need for other market ancillary services, such as FFR and fast FCAS.

Whenever inertia has market benefits, it could be valued at the marginal benefit that an additional unit of inertia may provide. While there may be multiple market benefits of inertia, the highest of these marginal market benefits is what could be used to set the price for inertia.

As discussed in Section 2.2, additional units of inertia may reduce the need for FFR and fast FCAS services and vice versa. The optimal economic dispatch will be at the point where the marginal cost of an additional unit of inertia equals the marginal cost savings from an additional unit of FFR/R6/L6, or vice versa. This is the point that satisfies the equimarginal principle.[23] This is depicted in Figure 12 below.

This sets a desirable level of discretionary inertia and the per unit price of inertia for the dispatch interval.[24]

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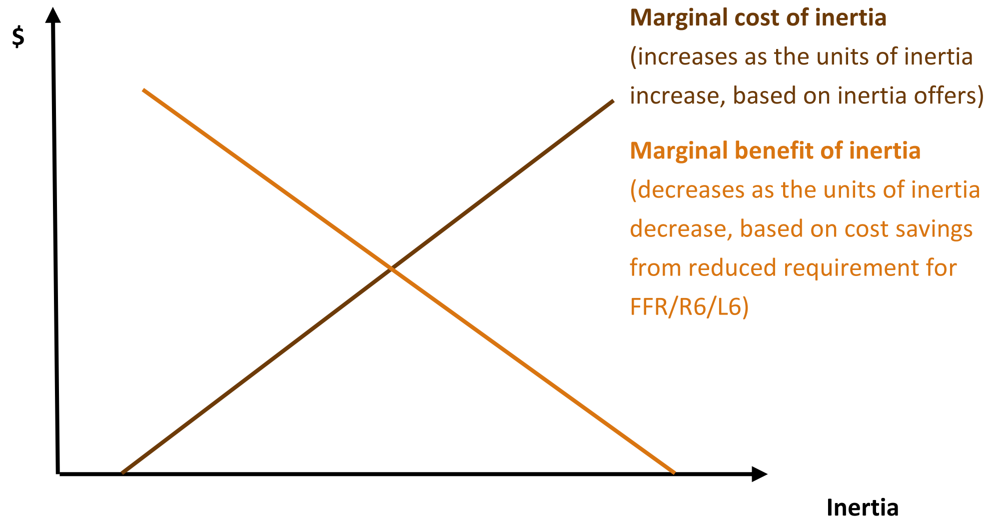
[22] To ensure that all nondiscretionary inertia service providers receive at least their bid price, the marginal inertia provider that sets the price of nondiscretionary inertia could receive payment in relation to all its inertia included in the marginal bid. Alternatively, the inertia units included in bids may be treated as divisible and thus the marginal inertia providers may be partially dispatched for inertia. This could lead to losses for the marginal service provider. This may be problematic for SynCons that would have to manage the recovery of their costs when only partially dispatched and paid for. Currently, MPs are responsible for managing these risks. Pre-dispatch processes help MPs identify these risks and respond to them. To further illustrate it may be the case that a 100MWs inertia service unit is dispatched to provide only 1MWs. The service provider may deliver 100 MWs inertia but may only be paid for 1 MWs of 'valuable' inertia. This treatment has precedence in the NEMDE, e.g., in FCAS dispatch. Like in the FCAS market, the inertia service provider would wear the impacts of its own inflexibilities.

[23] In economics the 'equimarginal principle' is frequently used for optimising resource mix. A frequently noted point is the inertia is lumpy and binary which could make the calculation 'clunky'. Given that the outcome of the optimisation is not actually applied to inertia dispatch, it is possible to linearise the provision of inertia, using the offer prices and the static inertia values from earlier steps and thus 'smoothing' the marginal calculations.

[24] To establish a value for a unit of discretionary inertia, a price expressed as $/MWs was used. Here prices are expressed as $/MW. This is possible when energy price band included positive MW values (i.e., the inertia was provided jointly with energy) but SynCons and other 'energy unbundled' inertia providers will need further consideration or an altogether different valuation.

Figure 12 Marginal cost and marginal benefit of inertia (equimarginal principle)



Discretionary inertia - Price and winner determination

It is proposed that only the lowest cost inertia service providers up to the level where the marginal benefit from inertia equals the marginal cost of an additional unit of inertia would be entitled to the payments. Market participants that continue to provide inertia (e.g., because they are dispatched for energy) would not be eligible to receive inertia payments in a dispatch period when they were not dispatched for inertia.[25]

While it was described as a sequence, it is envisaged that the decisions described in this Section regarding energy, inertia, FFR, and fast FCAS would take place simultaneously (or perhaps with the use of some iteration).

Examples of inertia dispatch under different power system operating conditions

In each dispatch interval, NEMDE determines a price for nondiscretionary inertia for the NEM (under normal operating conditions) and for each sub-network (under credible contingency and islanded conditions). These are based on the inertia dispatch offers and the minimum required inertia levels (which may be the NEM-wide inertia net, the minimum threshold inertia, or secure operating levels of inertia).

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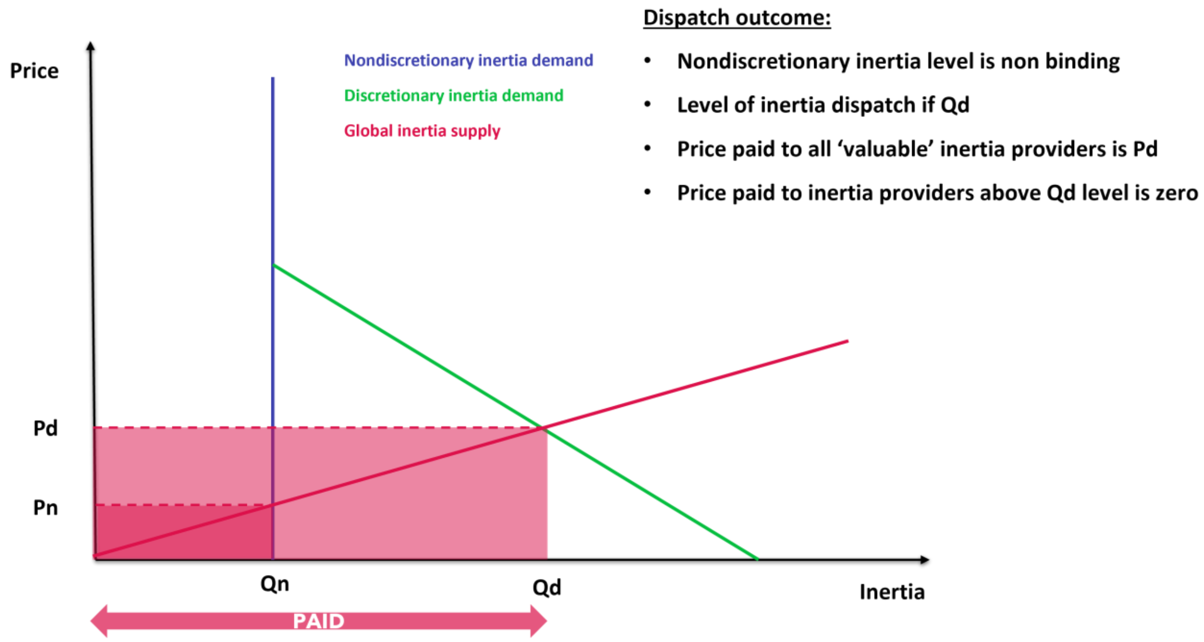
[25] There appears to be a level of inefficiency in that more inertia is provided than the level that is considered in the inertia-FFR/R6/L6 trade-off matrix. However, this treatment is necessary to ensure that FFR/R6/L6 prices remain efficient and that inertia and FFR/R6/L6 are treated at the same priority level. Any unit of inertia that would be paid beyond the 'equimarginal' point could potentially distort the outcomes at other ancillary service markets. An exception may relate to inertia contracts that relate to TNSPs' procurer of last rest role (see Step 10 below).

In each dispatch interval NEMDE also determines the price of discretionary inertia based on FFR and fast FCAS prices using the equimarginal principle described above (Figure 12) or another suitable pricing rule.[26]

In each dispatch interval there are inertia service providers that are dispatched in relation to either the nondiscretionary or the discretionary inertia. The discretionary level of inertia is in addition to meeting the system security needs but the inertia providers that are dispatched for nondiscretionary inertia also contribute to the discretionary inertia.

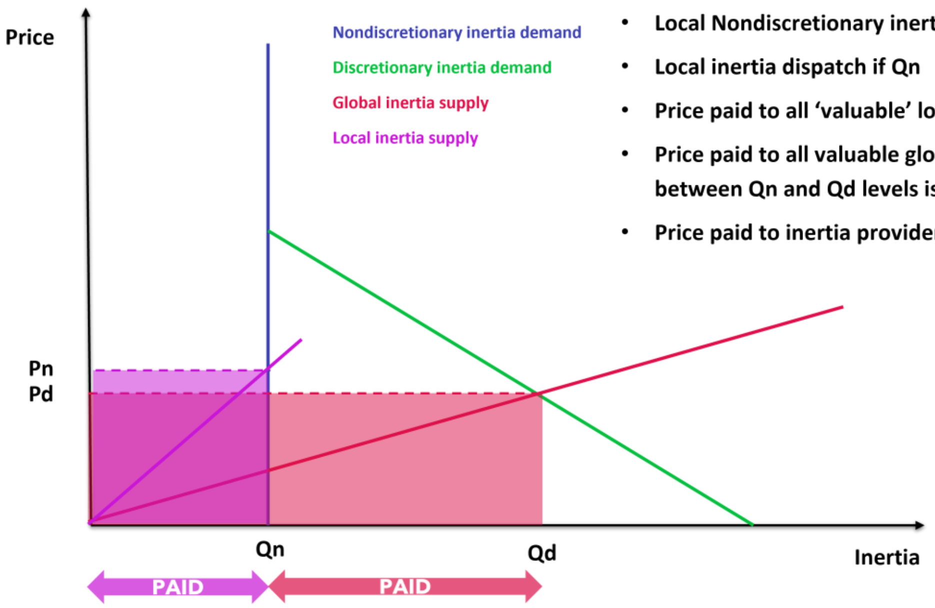
Let us consider three cases: (1) dispatch in normal operating state, (2) dispatch when there is a credible contingency event, and (3) dispatch under islanded conditions.

(1) Dispatch when power system is in a normal operating state



[26] For example, further assessment may reveal that the more relevant relationship for pricing is inertia's complementary relationship with other system services. In this case a concept that may be used to determine inertia prices is called the Production Possibility Frontier (PPF) method. This method is used to determine the optimal ratio of inputs, given their costs, while concurrently maximising the output.

(2) Dispatch when there is a credible contingency event



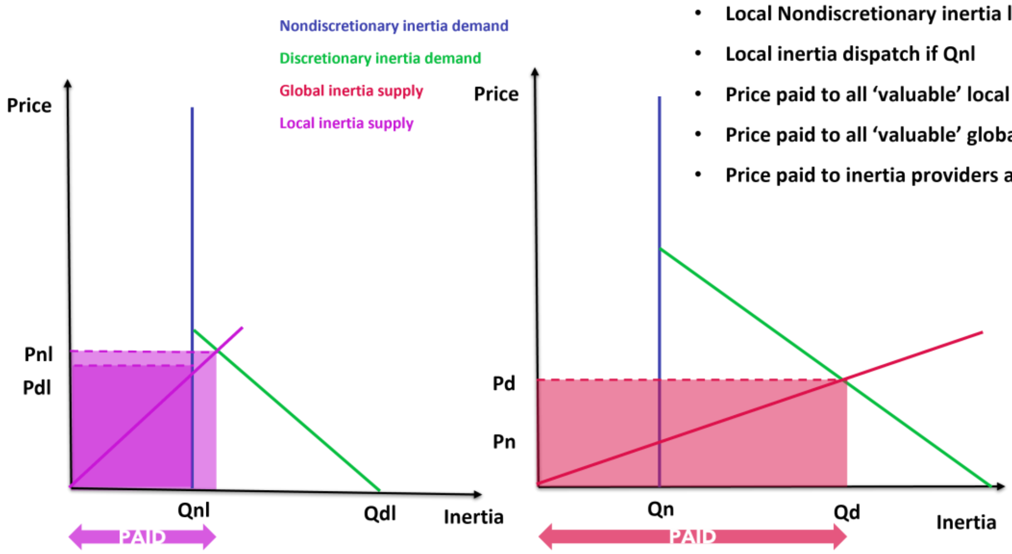
Dispatch outcome:

- **Local Nondiscretionary inertia level is binding**
- **Local inertia dispatch if Qn**
- **Price paid to all 'valuable' local inertia providers is Pn**
- **Price paid to all valuable global inertia providers between Qn and Qd levels is Pd**
- **Price paid to inertia providers above Qd level is zero**

(3) Dispatch if there is islanding – separation of inertia prices (local and global)

Dispatch outcome:

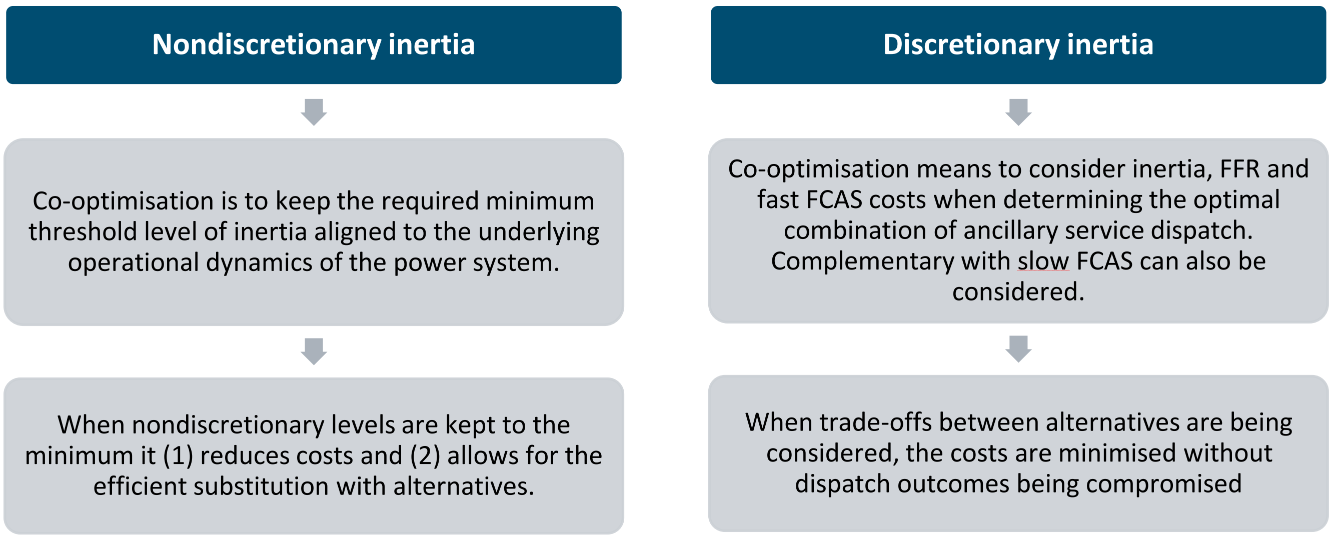
- **Local Nondiscretionary inertia level is binding**
- **Local inertia dispatch if Qnl**
- **Price paid to all 'valuable' local inertia providers is Pnl**
- **Price paid to all 'valuable' global inertia providers is Pd**
- **Price paid to inertia providers above Qd level is zero**



Co-optimisation

Figure 13 below describes what is understood under co-optimisation when determining levels and prices of nondiscretionary and discretionary inertia.

Figure 13 What does co-optimisation mean and why is it important?



Step 8: Settlement

Due to the asymmetric unbundling of energy-inertia (see market design principle 2), those not dispatched for inertia may still provide inertia. This provided, but not valued inertia, is not paid for but also not penalised. The reason why inertia above the ‘dispatched’ levels is not paid for (though may be provided) is so that inertia payments do not distort other related markets such as FFR and fast FCAS.

Table 5 below summarises the payments to inertia service providers.

Table 5 Summary of payments to inertia service providers

	Dispatched for nondiscretionary inertia	Dispatched for discretionary inertia	Not dispatched for inertia
Provides inertia	Paid the highest of the discretionary and the nondiscretionary price of inertia.	Paid the discretionary price of inertia.	No payment.
Does not provide inertia	Penalty in line with costs.	Penalty in line with costs.	No payment, no penalty.

With respect to each region, inertia service providers that are dispatched for both nondiscretionary and discretionary inertia would be entitled to the higher of the nondiscretionary or discretionary inertia price, but not both.

Market participants that are dispatched for energy and not for inertia yet provide inertia would not be entitled to inertia service payments.[27]

Settlement of energy and inertia payments for combined energy-inertia bids

As discussed above, and also laid out as market design principle 2, energy and inertia are treated as asymmetrically unbundled. When energy is dispatched, inertia may or may not be considered 'dispatched'. When inertia is dispatched, energy supplied together with inertia (if any) in the combined energy-inertia bid band must be dispatched. In this latter case, the energy price included in the bid should not be able to set the prices in the energy market. The service provider, however, is entitled to both energy and inertia payments. Given that this was an out-of-merit-order dispatch for energy, it may be the case that the energy bid of the service provider was lower than the spot market price. This risk is alleviated by the revenue received for inertia.

Some dispatch outcome options are further described in Table 6 below.

Table 6 Payments to service providers with a combined energy-inertia bid

Dispatched for energy?	Dispatched for inertia?	Notes
Yes, in merit order.	Yes	Receives energy spot price. Receives inertia price.
Yes, out of merit order due to inertia.	Yes.	Receives energy spot price (which may be below its bid price), bid price cannot set spot energy market price. Receives inertia price.
Yes, in merit order.	No.	Receives energy spot price Does not receive inertia price even if provides inertia.
~~No~~*	~~Yes~~*	*Not possible, see market design principle 2.

Step 9: Cost recovery

Various options are available regarding how to recover the cost of inertia paid to inertia service providers. It may be the case that recovering the costs of the discretionary and nondiscretionary components will necessitate different treatments.

Nondiscretionary inertia provides system security benefits. Inertia procured at the minimum threshold level during normal operating conditions provides the basis of the operation of the power system. The

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[27] The inertia provided by these market participants is valued as zero and is proposed that AEMO's co-optimisation does not include this inertia in setting FFR or R6 requirements.

costs of meeting the minimum threshold level of inertia may be recovered, for example, from Market Customers in proportion to their energy consumption in each relevant region in each of the dispatch intervals. Similarly, the cost of enabling a secure operating level of inertia during credible contingency events may be recovered from Market Customers.

Discretionary inertia provides market benefits. Identifying the ‘beneficiaries’ requires further consideration. For example, when discretionary inertia relieves constraints that have been invoked across interconnectors, it may be considered that (at least some of) the generators are direct beneficiaries of the discretionary inertia. Under other circumstances, for example, under high levels of renewable generation in the middle of the day, the need for discretionary inertia may relate to demand side generation or Market Customers.

In short, the cost recovery of both nondiscretionary and discretionary inertia requires further consideration to ensure that the costs are borne by those MPs whose actions are most directly linked to incurring the costs, and thus are best placed to manage the risks arising from these costs.

Step 10: Procurer of last resort

The current arrangements with TNSPs could be reframed as an arrangement so that TNSPs would become a ‘procurer of last resort’ for non-discretionary inertia.

Step 11: Market information provisioning role

AEMO’s market information provisioning role could be extended to include information on the performance of the inertia market.

Step 12: Market monitoring and enforcement

AER market ‘watchdog’ role could be also extended to market activity in the inertia markets.

4.3 Assessment of inertia spot market option

Criteria	Option 1: Inertia spot market option
Efficient level procured	Yes. Inertia procured reflects the inertia needs arising from the operational dynamics of the power system (demand for inertia), the costs of providing the inertia at various times and in different regions (supply of inertia) and also the cost of alternatives. Co-optimisation of both discretionary and non-discretionary inertia ensures that the level of inertia that is 'dispatched' (or valued) in the system is efficient.
Outcomes consistent with market dispatch and are co-optimised with FFR and other system services	Yes. Co-optimisation of nondiscretionary inertia ensures that the inertia levels procured are aligned to the underlying operational dynamics of the power system. Co-optimisation of discretionary inertia means that inertia, FFR and fast FCAS costs are also considered when the optimal combination of ancillary service dispatch is determined.
Effective in real-time, ensures inertia service is available when needed	Yes. Similar to energy, pre-dispatch processes provide signals for the need for inertia. Signals may be in the form of forecasting inertia needs and inertia price. In addition, there may be other processes such as 'lack of inertia' declarations. Inertia is dispatched through NEMDE and thus no additional processes are required to give effect to contractual obligations.
Efficient price signal of the value of inertia in an operational timeframe and under different operational conditions	Yes, it reflects the underlying supply and demand conditions of the inertia and FFR ancillary services. For example, the following outcomes are likely to be in line with a well-functioning inertia and FFR markets: • Under normal operating conditions when the nondiscretionary levels of inertia (NEM-wide safety net inertia) is non-binding, all 'dispatched (or 'valuable') units of inertia are rewarded using the same $ per MWS price. This price is also in line with the value of the operational trade-off with FFR and fast FCAS provision. • Under conditions of credible risk of islanding or an islanded system where the local inertia provision constraint is binding, local inertia service providers that are critical to maintaining system security may be paid at a higher marginal rate reflecting scarcity pricing. There is unvalued (and unpaid) inertia, but this is necessary to provide an efficient price signal and to accommodate operational reality of inertia service provision. This is similar to the treatment of the natural reserve headroom in the energy market.
Efficient investment signal	Granular (5-minute) and sub-network specific inertia prices provide valuable information for potential investors. This information is directly relevant for forecasting future revenue from the provision of nondiscretionary and discretionary inertia.
Risks allocated to those best able to manage them, avoids single view dominating decisions	AEMO is best positioned to determine the (likely) state of the operating system and the nondiscretionary levels of inertia required. However, regarding discretionary inertia, the level of 'dispatch' of nondiscretionary inertia is a decision that requires the consideration of technical and commercial trade-offs between inertia, FFR and fast FCAS. The technical nature of this trade-off is AEMO's role to determine. The commercial component of the trade-off is the role of MPs. MPs may be best positioned to determine the combination of services that their units are capable of providing and to bid in line with their capabilities and commercial interests. MPs can use the energy-inertia bid bands to this aim. While for some 'traditional' synchronous generators the provision of energy, inertia, and

	frequency control services may correlate with one another, this is likely to be less so for other technology. Regarding allocating costs to those best able to manage them, the details of the cost recovery process will determine to what extent this is achieved.
Minimise overall costs to consumers	Yes, overall costs are minimised. The approach of recovering the inertia ancillary service costs from Market Customers in proportion to their consumption would lead to similar outcomes as the current approach when the TNSPs recover the costs through tariffs from their customers. However, customers that reduce their load during times of high inertia demand could avoid some of these costs.
Technology neutral	Yes.
Simple and transparent	Relatively. Simpler than ahead commitment.
Consistency with NEM design principles.	Yes.

4.4 Issues that require further considerations

The following table captured some questions and consideration that need addressing when further developing this model. None of these appear to be 'show stoppers'.

Question	Answer
Could an inertia provider be constrained off if there is surplus inertia? **Is this a proposal for unit commitment?**	No. Some inertia market proposals aim to solve two problems at once: unit commitment and inertia pricing. The origins of this approach are that in energy markets supply must meet demand and no energy beyond demand should be dispatched.[28] However, this need not hold for inertia. For inertia, the requirement is to have *at least as much* inertia in the system as maintaining system security requires and, in addition, have *at least as much more* inertia as economically desirable. There are no technical requirements to limit inertia. Only economic limits exist, i.e., no payment should be made for additional units of inertia when the costs outweigh the benefits. ,Therefore, instead of capping (decommitting, constraining off) inertia, we can simply not value (not pay for) inertia when the economic limit is reached. AEMO in its recent submission to the System security rule changes consultation paper included a "warning" about the complexities of pricing inertia in the presence of unit commitment issues. We agree to this assessment but highlight that unit commitment is outside the scope of the option discussed above. In fact, the lack of unit commitment makes inertia pricing simpler. Under this option the decision to commit a unit (i.e., to be decision to be synchronised or not) remains to be that of the market participants in the presence of fixed and variable costs. This is similar to the considerations that market participants face today in relation to energy and FCAS. The market participants need to solve the same problem that they have been solving to date. The tasks of AEMO are to identify the required nondiscretionary levels of inertia for system security benefits and the additional discretionary levels of inertia with market benefits.

[28] It is also a typical "winner determination" treatment in market design (e.g., reverse auctions used for procurement) to distinguish those who are winners and those who are non-winners and to ensure that this distinction is replicated in the physical provision of the goods or services procured. However, the distinction between the technical and economic treatment of inertia allows the two aspects to be treated differently.

Question	Answer
	It is our understanding that using the joint energy-inertia bid formulation (with the potential to enter zero energy bids) enables the outcomes proposed in the Rule change submitted by Hydro Tasmania.
How can marginal prices be established when inertia is provided in a binary and lumpy fashion?	There may be at least two possible approaches to pricing inertia. The advantages and disadvantages and any potential technical complexities (e.g., implementation in the NEMDE) require further consideration. It is important to note that that following discussion relates pricing inertia, not to its level of actual physical provision. One option is that, for the purpose of establishing the price for inertia, the bids are considered 'lumpy' and the marginal inertia service provider is fully included in the dispatch, i.e. all of its inertia bid is considered valuable (i.e. the inertia dispatch is 'rounded up' to the level of the marginal inertia bid). The marginal inertia provider faces no risk of only partially recovering its costs. An alternative is to 'linearise' the inertia bids. Under this option the marginal service provider may be 'partially dispatched' in an economic (but not technical) sense. There is no intention (or risk) for that inertia to be actually curtailed. Linearising the inertia values allows us to smooth the inertia supply curves. This in turn facilitates the discovery of the marginal prices with regards to FFR and fast FCAS services. Alternative pricing mechanisms such as Vickrey-pricing (using the price of the first *excluded* inertia provider to set the price) may also be explored. It may also be the case that one approach (e.g., 'lumpy' treatment) is better suited for pricing nondiscretionary inertia and another approach (e.g., linearised treatment) better suits the pricing of discretionary inertia.
How to treat synchronous condensers that consume power while providing inertia?	The power consumption or windage losses are likely to be small. Auxiliary loads for conventional generators are currently excluded from dispatch. Nevertheless, there are easy and already established ways to deal with this, if required. As discussed above, inertia provision can be considered unbundled from energy. In the proposed spot market design, inertia is included in dispatch on the supply side. When inertia is provided by SynCons, they can be included as "zero energy" bids. Any energy consumption that occurs (e.g., sycons draw from the grid while providing inertia) can be dealt with as a separate "demand side" transaction. This treatment is not without precedence in the NEM. Since the unbundling of FCAS services, FCAS may be provided by demand side participants without providing energy. Consumption of energy while providing FCAS services is resolved through separate settlement processes. In the NEMDE, FCAS offers by demand side participants are represented as FCAS offers at zero energy levels. Instead of a 'trapezoid', a vertical line represents the service provider at zero energy dispatch levels. Inertia provided by SynCons can be represented the same way. When SynCons draw energy, they essentially pay (rather than receive) the RRP. When energy prices are positive, the synchronous condenser would incur costs in providing inertia. These would need to be factored into its bid price. When prices are negative, a synchronous condenser may earn revenue for energy consumption in addition to potentially receiving revenue for inertia. Alternatively, SynCons may be included in dispatch as demand a side participant. To ensure competitive neutrality between supply and demand side participants, some rules may need to be revised. For example, according to Rules clause 3.8.7(h) energy band prices for dispatchable loads must be greater than or equal to zero, whereas a different price floor applies to energy band prices for dispatchable generating units.

Question	Answer
Some loads may have inertia benefits. Should these loads be rewarded as well?	Yes. For example, scheduled loads with a calculable inertia value (H) could be included in dispatch. AEMO could consider their inertia bids similar to those considered for generating units. AEMO could dispatch a combination of load and generation to meet the inertia requirements. The inclusion of demand-side inertia could further reduce costs, improve dispatch outcomes and improve co-optimisation with FCAS services.
Some service providers are able to provide different combination of energy/inertia levels. Can this be incorporated in the spot market model?	If it is a single unit that is able to provide different levels of energy/inertia combinations, then this could be incorporated in the proposed model. To keep bidding simple, the inertia levels may need to be 'fixed' to certain bands. Similarly, if the energy/inertia combinations are provided by a group of units that are included in dispatch as a single unit (e.g., bids submitted using the small generator aggregator framework) then this can be accommodated. If, however, the energy/inertia combinations are provided by a group of units at multiple connection points such that it is the combination of the operation of multiple units' that creates the inertia (e.g., as may be for grid forming technologies?) then this may be dealt with through the recently established Integrated Resource Provider (IRP) registration process.
Could grid forming power electronic converters be incorporated in this mechanism?	See response above, may be incorporated using the IRP process.
Could there be a competitive disadvantage for some generators if they are required to use band 1 for zero energy and they only have nine bands left to express different levels of energy?	Yes, it seems reasonable that generators that can also operate in SynCon mode should have an additional price band made available to them (e.g., band zero) to express a "zero energy" bid. Battery providers will soon also have more energy bands (up to twenty) available to them. There remains a range of detail to be worked out. One of them is how to ensure that the market design is neutral and market design details do not disadvantage a market participant and bid formation is a key component of that.
Could some generators exert market power in some circumstances?	It is important to note that, that some market participants that may be required to meet, for example, system security needs already have a differentiated ability to take advantage of certain situations or events. For example, some generators may be in a better position to negotiate with TNSPs, or they are more likely to be included in the energy dispatch merit order (even with high energy bid prices) under certain circumstances. A transparent spot market where inertia service providers compete on equal footing has the ability to minimise the potential market power of certain participants. Given the transparent nature of spot markets, and the scrutiny that may be applied to market participants' behaviour, spot markets are well suited to facilitate addressing any potential systematic market power issues, should there be any. Market power issues cannot be easily identified, scrutinised, and addressed when goods and services are traded via non-transparent bilateral negotiations. Prices of discretionary inertia are set in combination of bids in the FFR and fast FCAS markets. It would be very difficult for inertia providers to influence market prices when substitutes are readily available in other markets. When it comes to non-discretionary inertia, market power requires some further consideration. First, the expectation is that in the future some market participants will be able to provide inertia, or inertia-substitute services in a quick and nimble fashion. Battery storage providers, for example, could quickly undercut a market power attempt by a market participant. This suggest that it will be important to ensure that definitions or

Question	Answer
	registration requirements do not unduly crowd out service providers that could provide value and play important roles in the market. Also, adding a service to the spot market *increases* the level of competition rather than reduces it. As demonstrated above, service providers must ensure that they are competitive in *both* markets in order to receive both energy and inertia payments. Market design details are, however, important. Currently, the Rules make it clear that market participants' must bid in line with the capabilities of their units. This principle is adopted (see market design principle 4 above). 'Bidding in good faith' obligations would continue to apply. An area that may need further detailed consideration relates to the asymmetric unbundling of energy and inertia (see market design principle 2 above). Under some circumstances when inertia is dispatched, the energy component of a bid is also dispatched. But not necessarily the other way around.
FFR contingency reserves are measured in MW, whereas inertia is measured in MW seconds. How to reconcile these?	For service providers other than SynCons, the inertia bid includes a MW value (in addition to a MWs value) that may be used to reconcile the two. This needs further consideration.
Could or should the fast start inflexibility profile be allowed for inertia providers with regards to their first energy price band?	Yes. Dispatching inertia is like dispatching generators at MinGen levels.
Does inertia need price floors and market price caps?	Possibly. The role of the Reliability Panel may be extended to consider price floors and market price caps for inertia. For example, the Panel may consider the shadow prices that may be derived in relation to inertia (see Option 3) when setting price caps.
What are the expectations regarding inertia prices under this model?	Inertia prices need to reflect inertia supply-demand and power system conditions which are linked to energy and other system security and network conditions. The more dynamically priced are determined the more efficient the price signals. The objective of the market design is to reveal these prices, consistent with dispatch outcomes. Prices being "low" or "high" are not an indication of a market being efficient.
How to treat TNSPs' SynCons in this model?	Several approaches may be explored. For example, TNSPs' SynCons may be treated as part of a 'procurer of last resort' arrangement, and these would need to be kept outside the inertia spot market unless there is an event that necessitates their deployment. This is similar to the treatment of resources under the RERT arrangements. Alternatively, TNSPs may be required to bid the inertia from their SynCons into the market and to compete on equal footing with other inertia providers. If so, it requires further consideration whether TNSPs' SynCons should be able to compete in both the nondiscretionary and the discretionary inertia market or only in the former.

5. Option 2: Ahead or close to real-time market for inertia

5.1 Key features

This option is based on ERM's Power System Security Ancillary Services (PSSAS) model. Key features of this option include that

- Dispatch is through the NEMDE and the pre-dispatch process.
- The dispatch of services would be across multiple dispatch intervals.
- There is likely to be a unit commitment for security (UCS) or synchronous services market (SSM) required in the NEM as a pre pre-requisite for this option to be implemented.

5.2 Description of ahead or close to real-time market for inertia

- Establish ancillary services (RoCoF/Inertia, Voltage Control, System Strength), jointly called Power System Security Ancillary Services (PSSAS).
- The need for each service is based on AEMO's determination of power system requirements.
- Dispatch is through the NEMDE and the pre-dispatch process.
- Dispatch is co-optimised with energy and FCAS (and ramp rate, if implemented) over multiple dispatch intervals. The least cost combination of the required services would be dispatched at any given time, with dispatch instructions issued on an 'as required' basis.
- A provider could be dispatched for the provision of one or any combination of services simultaneously, if capable of doing so.
- A generator dispatched for PSSAS would only receive the differential in $/MWh between the RRP and their offer price up to their bid minimum load.
- No PSSAS payment for output above their bid minimum load.
- A generator can offer and provide FCAS and energy output above minimum load at the RRP.
- Non-generating unit provider: the bid is on a $ per Dispatch Interval value, min/max time of service.
- Once dispatched for PSSAS, the offer price or minimum load value cannot be altered for the duration of the provision of PSSAS. Rebidding is allowed for volumes above price bands used for the PSSAS offers.
- Costs would be recovered on a regional basis, split 50/50 between market customers and generators, based on the energy produced or consumed in those trading intervals where PSSAS were dispatched.

5.3 Assessment of ahead of close to real-time market for inertia option

Criteria	Option 2: Ahead or close to real-time market for inertia
Efficient level procured	While making decisions in advance, or across longer time frames, can lead to a reduction in system security risks, there are also costs of applying such arrangements. For example: • Higher than necessary costs may be incurred due to potential over provision of a service. • It may remove any dynamic price signal for the provision of a similar, substitutable service, that may be able to meet the system security requirements at a lower cost. • It has implications for the options that are available in later dispatch periods. • There may be limits to scheduling efficiency and coordination, i.e., there may be no one ahead timeframe that suits every service and thus there is a risk of distorting market prices or outcomes.
Outcomes consistent with market dispatch and are co-optimised with FFR and other system services	The design intends to achieve this but due to ahead commitments being made the ahead decision may turn out being inconsistent with spot dispatch outcomes retrospectively. Co-optimisation is also distorted. Due to the interlinkages between inertia, FFR and fast FCAS, when inertia is committed ahead, the rest of the services will either need to 'complement' the committed inertia or they need to be 'ahead' committed as well. For FCAS and fast FCAS this is difficult as it is inherently linked to energy levels.
Effective in real-time, ensures inertia service is available when needed	Yes.
Efficient price signal of the value of inertia in an operational timeframe and under different operational conditions	In theory, yes. In practice the price signal may be distorted due to inaccurate ahead decision. Inefficiencies may not be apparent until 'side-effects' develop. If the ahead commitment also includes a 'bundled price' for multiple services, this undermines the price signals not only in the ahead market but in the spot market as well.
Risks allocated to those best able to manage them, avoids single view dominating decisions	No, market operator makes ahead decisions. Market operator's view of the 'ahead' needs of the market dominate decisions and implicit in these are economic trade-offs.
Minimise overall costs to consumers	No. Inaccurate ahead decisions are borne by all market participants in ways that is difficult to attribute and avoid. Deciding who should pay is hard. If Market Customers pay, free riding issues arise. If certain types of generators pay (e.g., VREs), the benefits could be limited. It could also dulls the incentives to alleviate the problem, especially if prices in the spot market become depressed as a result of the introduction of the ahead market.
Simple and transparent	Likely to be complex with implications for almost all aspects of the current market mechanism and settlement.

Open to various technology	Yes, in theory but ahead commitment may also disadvantage some technology and thus it is not necessarily a technology agnostic solution. Also, the prices and dispatch of different types of services may be distorted.
Consistent with current NEM design principles.	No. Bidding is complex, and it requires establishing additional processes. It is a move towards a centralised model rather than respecting underlying decentralised market.

6. Option 3: Shadow pricing of inertia

6.1 Key features

Shadow pricing of inertia involves establishing a value for inertia. The 'shadow price' is equal to the marginal cost of a constraint, i.e., how much money could have been saved if the binding constraint was relaxed by a very small amount.[29] This hypothetical cost savings from an additional unit of inertia is taken to be the marginal value of inertia. Options may include to use the Inter-regional RoCoF constraint or the RoCoF control constraint to restrict the frequency nadir (WEM-type RoCoF Control).

6.2 Description of shadow pricing of inertia

Option A: Inter-regional RoCoF constraint: Using the Inter-regional RoCoF constraints, the incremental value of inertia could be determined by the value of an incremental increase in the flow on the interconnector. This option was explored through previous Rule change requests. AEMC considered a range of cost recovery if shadow pricing were introduced, including:

- SRA proceeds plus additional funds from TNSPs: if total inertia payments over a given period exceeded total SRA proceeds over the same period, additional funds would be recovered from TNSPs.
- Additional charge to generators and consumers: the cost of the inertia payments would be recovered directly from generators or consumers through an additional charge.

Option B: WEM-style RoCoF control: The WEM RoCoF control is a constraint-based control. ’Safe’ levels of RoCoF are determined and added to the FOS to ensure power system stability. These are then operationalised in the clearing engine optimisation. The requirement for the RoCoF Control Service and the corresponding cost is driven by:

- Clearing engine optimisation of the trade-off between the contributions of RoCoF Control service and Contingency Reserve to restrict frequency nadir; and
- RoCoF safe limits, which are set to avoid damage to generators and load equipment, and to ensure proper operation of network components.

The costs of RoCoF Control Service will be shared between generators (based on their RoCoF ride-through capability) and loads (based on share of consumption unless opts to be treated on a ride-through capability basis).

[29] This is similar to what is described in Section 4 under marginal costs and the equimarginal principle.

6.3 Assessment of shadow pricing of inertia

Criteria	Option 3 Shadow pricing of inertia
Efficient level procured	Shadow pricing does not pay for inertia when there is 'enough' or efficient level of inertia. Price signals only exist when low level of inertia results in a constraint becoming binding. In absence of inertia bids, it is not known whether it is 'efficient' or 'inefficient' for the constraint to bind at that level. The constraint reflects a technical limitation, assuming that the prices of all relevant factors have been incorporated. Given that shadow prices do not adequately capture the value that inertia provides to the system, it is unlikely to be made available at levels to address the physical requirements of the system.
Outcomes consistent with market dispatch and are co-optimised with FFR and other system services	Outcome is consistent with market dispatch. More actively considering shadow prices in dispatch decisions may lead to benefits but proper co-optimisation requires inertia bids. There is no 'procurement' proposed in this model. Co-optimisation (if happens) is not due to the shadow prices, but the co-optimisation would be reflected in the shadow prices.
Effective in real-time, ensures inertia service is available when needed	No. On its own, shadow pricing does not provide a tool for procuring additional inertia. Additional inertia service at high shadow prices may undermine the price signal itself. There is also a poor link between behaviour and payment. If generators respond to the pre-dispatch inertia shadow price signal there may be sufficient inertia in the market to alleviate the constraint. If the constraint does not bind, generators will not receive any payments for inertia service provision, only for energy. In order to ensure that inertia is available in dispatch, there would need to be a mechanism that obliges inertia providers to provide inertia when shadow prices indicate there is a need. But which ones of the inertia providers should come online? Resolving this issue leads back to a market mechanism (Option 1 or 2 above).
Efficient price signal of the value of inertia in an operational timeframe and under different operational conditions	Each shadow price is a partial value of the whole of value that inertia provides. Inertia is only valued 'at the margin' in this model whereas it appears to have more fundamental function. This suggests that shadow pricing may perhaps be used in combination with another mechanism.
Risks allocated to those best able to manage them, avoids single view dominating decisions	No. AEMO's views on system needs dominates constraints and thus decisions.
Minimise overall costs to consumers	Not sure. The lower the levels of inertia the higher the shadow prices.
Simple and transparent	Yes, if information on real-time constraints may be provided by the market operator. However, the "market insight" reflected in the shadow prices may be more difficult to gauge. It is not clear whether at high shadow prices the incentive would be for a service provider to provide inertia.
Technology neutral	Yes.
Consistent with NEM design principles	Somewhat. But "shadow prices" and "payments for inertia services" are inversely related and reconciling these requires further mechanisms to be introduced.

7. Option 4: Procurement contracts

7.1 Key features

As described in Section 3, an inertia procurement framework exists already whereby TNSPs are required to procure and make continuously available the minimum required inertia level. This framework provides the base. Four ‘refinements’ or extensions to the existing framework are discussed in this section, in varying levels of detail.

7.2 Description of procurement contract options

Options 4A: TNSPs are required to procure inertia at the minimum required levels in all sub-networks, regardless of whether AEMO establishes that there is an inertia shortfall.

- Issues: It may be perceived that there are no benefits from this option when there are plenty of service providers (i.e., there is no shortfall of inertia). This option provides the minimum level of inertia for system security benefits and as such, it establishes the basis for market benefits to be obtained from additional levels of inertia. However, the mechanism does not provide an avenue for the market benefits to be realised as procurement does not extent to inertia beyond the minimum required level. Inertia levels are also not co-optimised with FFR and fast FCAS services.

Option 4B: Place an obligation on AEMO to procure some inertia <u>above</u> the minimum required level of inertia for market benefits. Different types of contracts may be established, for example baseline and flexible inertia contracts. While TNSPs obligation is in relation to a sub-networks, AEMO would procure inertia for NEM-wide market benefits.

- Issues: AEMO would need to form a view of the required levels of inertia. This is inherently interlinked with its views of system conditions such as the likely status of the power system, the availability and costs of FFR and fast FCAS services, operational demand, and how these relate to the inertia needs of the system. Furthermore, AEMO would need to form a view of the (minimum and maximum) payments that may be reasonable to be paid to inertia service providers. This requires AEMO predicting the availability and the costs of FFR and fast FCAS services and based on its predictions, to make inertia procurement decisions. The inertia contracts would need to be operationalised at the dispatch interval level. This necessitates a mechanism of scheduling generators with out-of-market contracts. This could impact on and distort other markets, like energy and FCAS.

Option 4C: Keep current obligations placed on TNSPs to procure inertia but require that those contracted by the TNSPs bid in the energy market in line with their contractual obligations to deliver inertia when a credible contingency event occurs.

- Issues: This proposal is similar to how NCAS equipment must currently automatically generate reactive power as a means to provide Voltage Control Ancillary Services (VCAS) when credible contingency occurs. Applying this approach inertia is likely to require a mechanism to schedule out-of-market contracts. However, inertia provision comes jointly with energy provision. Dispatch of the energy (and thus the provision of inertia) depends on prices bid by all market participants, not just the ones contracted to supply inertia. Also, some SynCons currently sit outside of market dispatch and their inertia provision is not 'seen' by the market. Also, this option may be viewed as expensive as there may be lower cost inertia providers that may not be in a position to enter into a long-term contract with a TNSP.

Option 4D: Shift the obligation from TNSPs to AEMO to procure the minimum required level of inertia through standardised short-term inertia supply contracts using reverse auctions, organised quarterly. Contracts would be for short periods only, potentially mimicking financial contract structures (e.g., baseline and peak quarterly products). AEMO would be required to establish the minimum required inertia in a more nuanced way. Successful participants would be required to provide inertia when receiving a 'trigger' from the TNSP or AEMO. The auction would also have a minimum price that the auction has to clear.

- Issues: This could provide efficiency gains and more transparency relative to current arrangements. AEMO would need to form a view of the required levels of inertia and inertia requirements would likely remain static throughout the short contract terms (e.g., quarterly base inertia contract). Like the current TNSP arrangements, this is likely to lead to over-procurement of contracts. Contracted parties are rewarded for AEMO's conservative view (i.e., when AEMO overestimates the likelihood of islanding or mis-estimates operational demand conditions). AEMO would need to form a view of the (minimum and maximum) price it should be willing to pay (on behalf of customers or market participants) for inertia. Implementing this option also necessitates a mechanism of scheduling generators with out-of-market contracts. This could impact on and distort other markets, like energy and FCAS. For example, when inertia providers receive a 'trigger' to provide inertia, there could be other inertia providers that would be displaced by these generators being brought into the market. (See assessment of current regulatory arrangements in Section 3.) Despite the above issues, this option has some appeal. When procurement contract period is sufficiently short and procurement decisions take place near real time, over-payments and errors from predictions are reduced, and this option starts to resemble to the inertia spot market options discussed in Section 4.

7.3 Assessment of procurement contract options

Criteria	Option 4: Procurement contract options
Efficient level procured	This option has some theoretical appeal. In theory, TNSPs or AEMO may be able to consider the inertia needs of the system and make holistically efficient decisions. However, in practice there is a risk that procurement approaches may lead to "gold-plating" in the form of over-procurement of inertia due TNSPs' decisions being driven by complex regulatory incentives. (For example, if minimum required inertia is lowered, then inertia capacity installed by TNSPs could become 'excess' but TNSPs would continue to receive a regulated payment under the RAB.) Similarly, when AEMO procures inertia contracts, AEMO may be inclined to cater for a wide range of events and to procure at levels that requires the highest levels of inertia. Static procurement is unlikely to lead to dynamically efficient levels of inertia. The efficiency can be increased when the procurement timeframe and the 'aheadness' of decision is reduced. If the procurement timeframe is sufficiently short (e.g., 5-minute inertia contracts) then Option 4D approximates the inertia spot market. For this reason, there may be a value in exploring this option further.
Outcomes consistent with market dispatch and are co-optimised with FFR and other system services	No. Procurement outcomes may not be consistent with dispatch outcomes. They also take place ahead of time. Co-optimisation can also not be achieved through procurement contracts.
Effective in real-time, ensures inertia service is available when needed	It can be. However, the costs of making inertia available continuously as a 'stand by' facility could be high. Currently, the TNSPs contracted inertia is not generally made available to the market. The inertia procurement level is based on a static measure and does not accurately reflect the real-time inertia requirements of the power system.
Efficient price signal of the value of inertia in an operational timeframe and under different operational conditions	No. No transparent price signals. Prices may only vaguely reflect operational conditions.
Risks allocated to those best able to manage them, avoids single view dominating decisions	No. TNSPs and AEMO make decisions, but costs are borne by customers and MPs.
Minimise overall costs to consumers	No.
Simple and transparent	Appears simple but the contract between service providers and TNSPs would be quite complex. It is not transparent.
Technology neutral	It depends on the details of the inertia contracts and the extent that inertia providers with different technology may be able to comply with the contractual obligations.
Consistent with current NEM design principles.	Not really. It is an out-of-market mechanism.