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Thursday, 20 August 2020

Ben Hiron
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Hiron

RE: System Services Rule Changes

ERM Power Retail Pty Ltd (ERM Power) welcomes the opportunity to respond to the Australian Energy Market Commission's system services rule changes consultation paper (the Paper).

About ERM Power

ERM Power (ERM) is a subsidiary of Shell Energy Australia Pty Ltd (Shell Energy). ERM is one of Australia's leading commercial and industrial electricity retailers, providing large businesses with end to end energy management, from electricity retailing to integrated solutions that improve energy productivity. Market-leading customer satisfaction has fuelled ERM Power's growth, and today the Company is the second largest electricity provider to commercial businesses and industrials in Australia by load[1]. ERM also operates 662 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, supporting the industry's transition to renewables.

http://www.ermpower.com.au
https://www.shell.com.au/business-customers/shell-energy-australia.html

General comments

ERM Power appreciates the AEMC's decision to combine the six rule changes into a single consultation paper so that they can be considered alongside each other and within the context of the Energy Security Board's (ESB) post-2025 review of the National Electricity Market (NEM). The six rule changes proposed offer a range of potential solutions to some of the challenges facing the NEM now. Many of the current challenges are likely to be exacerbated over the coming years as synchronous dispatchable generators, which have provided the necessary power system services as a byproduct of producing energy, retire as the market transitions to greater volumes of variable renewable energy and distributed energy resources.

As is made clear by the scope of rule changes and the AEMC's consultation paper, there is a wide range of potential approaches and possible solutions ranging from market-based to more centralised in design. ERM Power favours models which support open and transparent markets. We believe this results in clear and enduring investment signals for the ongoing provision of energy, and other power system services that will be required for the continued operation of the NEM into the future. We note there is considerable overlap with these rule changes and the ESB's proposed Unit Commitment for Security (UCS) proposal. The ESB issues paper on system services and ahead markets canvassed a range of possible approaches form the lighter-touch UCS-only model, to a full-scale centralised ahead market with system services.

[1] Based on ERM Power analysis of latest published information.

Given the trends in the energy system, we see there is enough evidence to consider expanding the current ancillary services markets in order to provide a range of other system services including ramping, synchronous (real) or synthetic inertia and fast-frequency (very fast contingency frequency control ancillary services - FCAS) response. We also acknowledge that given the nature of the power system and these system services, some degree of 'aheadness' in the issuing of a dispatch instruction will be necessary in order to ensure these services are available when required. Determining how far ahead this needs to be in order to balance a least-cost approach against the need to ensure that services are available for delivery will be one of the key challenges. It may be that there is no single timeframe suitable for the provision of all services and instead, multiple windows will be needed depending on the service being delivered.

Here we present our response to the consultation paper in the form of a proposed system services market outlining how the market would function and be priced. We believe that our proposed model represents a sensible and balanced design that will enhance power system security in a way that supports market-based responses. We consider that our proposed approach would best meet the National Electricity Objective by offering flexibility for dispatch of the required system services while finding the lowest-cost solutions to address the power system needs.

Given the inter-related nature of these rule changes and with the ESB's post-2025 review of the NEM, we recommend that the AEMC issue a Directions Paper as a next step rather than moving straight to a draft determination. This would allow the Commission to refine discussions and explore the relevant issues more deeply with stakeholders. It would also help align the timing with ESB's work and develop a consistent response.

Power Systems Services Ancillary Services – overview

ERM Power's proposed model would establish a new market ancillary service, termed the Power System Security Ancillary Services (PSSAS). PSSAS includes provision of the following PSS services:

- Rate of Change of Frequency Management (Inertia)
- Voltage Control
- System Strength

We also believe the design of the PSSAS market would allow for the provision of other essential power system services requiring similar dispatch outcomes should these emerge in the future.

A provider could dispatch for provision of one or all 3 services simultaneously if capable of doing so. The need for each service would be based on AEMO's determination of power system requirements with dispatch through the National Electricity Market Dispatch Engine (NEMDE) and the NEMDE pre-dispatch run process. Dispatch would be co-optimised with energy, frequency control ancillary services (FCAS) and ramp rate ancillary services (RRAS), if implemented. The least cost combination of the required services would be dispatched at any given time, with dispatch instructions issued on an as required basis as for current market ancillary services.

Dispatch

In practice, AEMO would monitor forecast power system inertia, voltage control capability and system strength in pre-dispatch and at times of forecast power system security services deficiency, schedule additional PSSAS providers into service to remove the forecast power system security service deficiency.

AEMO would wait for the last time available before dispatching PSSAS based on offered time(s) to achieve provision of the service. For a generating unit, this would be the time required to achieve minimum unit output, while for a non-generating unit (like a synchronous condenser) it would be the time required to commence providing the service.

For PSSAS, AEMO would be allowed to issue a Dispatch Instruction that covered multiple dispatch intervals in the Energy market. This would ensure that plant can be dispatched for minimum run times where necessary and to ensure delivery of services over a particular time period.

PSSAS would also allow for dispatch of additional power system services in the event that a PSS deficiency was identified by AEMO following a credible or non-credible contingency event within a quick time period and at least cost to the market.

AEMO would still retain the right to issue a Clause 4.8.9 Direction, if required, to maintain power system security.

Pricing

In terms of payments for providing the services, a generator dispatched for PSSAS would only receive the differential in $/MWh between the energy market regional reference price (RRP) and their offer price up to their bid minimum load. A generator would not receive the price outcome differential for metered dispatch output above their bid minimum load. A generator would retain the right to offer and provide FCAS and Energy output above minimum load. If dispatched above minimum loading for provision of FCAS or Energy, metered Energy output above minimum loading would only receive the RRP.

Where a scheduled generating unit has the capability to operate in synchronous condenser mode to supply PSSAS, or the service is provided by a non-regulated synchronous condenser, the provider would bid a $ per Energy Market Dispatch Interval value to operate in synchronous condenser mode.

PSSAS payments to a scheduled generating unit operating in synchronous condenser mode would cease in the Dispatch Interval when metered output was recorded above 0 MW unless the scheduled generating unit had been issued a Dispatch Instruction to operate as a generating unit in the Energy market and maintain PSSAS dispatch. Pricing in this instance would change to a $/MWh basis, the same as for any generating unit providing PSSAS.

A generating unit with the capability to provide Ramp Rate Ancillary Services (RRAS), if implemented, and PSSAS simultaneously, would only receive settlement payment for the provision of both ancillary services based on their higher cost offer. Multiple payments would not be received for the provision of both services simultaneously by the same generating unit.

Similar to how the FCAS market interacts from a price determination perspective with the Energy market, the Energy market RRP is determined on the basis of pricing absent the dispatch of PSSAS units at minimum loading.

The proposed PSSAS design includes a market price cap and market price floor. We recommend the Reliability Panel be able to review and adjust the PSSAS market price cap and market price floor as part of the Reliability Standard and Settings review process.

Bidding

A supplier of PSSAS would be required to be available for service within the offered time period as set out in their bid. In the case of a Scheduled Generator this represents the time to start (if off-line), synchronise and achieve minimum loading capability within an offered timeframe following issue of a dispatch instruction by AEMO for the provision of PSSAS. A provider would be required to remain in-service based on the offered minimum and maximum time period in accordance with AEMO’s dispatch instruction.

Once dispatched for PSSAS the service provider would not be allowed to alter its offer price or minimum load value for the duration of the provision of PSSAS for which the dispatch instruction applied.

Notwithstanding, a generator would be able to rebid volume in price bands above that utilised for the PSSAS offer in accordance with clauses 3.8.22 and 3.8.22A for the provision of Energy. Unlike where a Clause 4.8.9 Direction is issued for provision of power system services, the full maximum availability of a generating unit would remain available for dispatch in both the Energy and FCAS markets.

A generator could rebid its minimum load based only on a verifiable plant condition. However, settlement for the duration of the period for which the dispatch instruction applies would be based on the original bid's minimum load at the time the PSSAS offer was dispatched.

Once issued a dispatch instruction, a PSSAS service provider would only be able to withdraw from the provision of PSSAS based on a verifiable plant condition.

Competitive tension would exist between generators for the provision of PSSAS. Generators and non-generators offering the lowest combination of costs at minimum loading, the unit(s) minimum loading value(s) and the applicability of any start costs or dispatch interval costs as well as the provision of the required ancillary service would be taken into account by AEMO in determining the lowest cost outcome to the Market for provision of the required service.

Provision of any PSSAS could be restricted to scheduled generating units, non-regulated synchronous condensers (if they are capable of providing), and potentially if approved, BESS, this would provide AEMO confidence regarding actual provision of dispatched services.

AEMO would select the least cost provider(s) to supply the required services at any given time and issue Dispatch Instructions.

Cost recovery

Costs would be recovered on a regional basis, based on overall costs incurred in the respective Trading Interval during the Settlement Billing Week based on 50 per cent from Market Customers and 50 per cent from generators and battery energy storage systems. These costs would be determined based on the energy produced or consumed in those trading intervals where PSSAS was dispatched.

Appendix A contains a table summary of the key elements of our proposal.

System strength

ERM Power considers that in attempting to address system strength issues, a decentralised market-based approach, similar to Hydro Tasmania's and with some overlap with Delta Electricity's rule change, is most likely to lead to a more efficient and lower-cost response. We do not consider that a centralised response akin to TransGrid's rule change proposal will lead to an optimal response that meets the National Electricity Objective (NEO). Rather, a centralised approach may lock-in inefficient outcomes, with the risks of over investment transferred to energy consumers on a long-term basis, via network infrastructure included in transmission networks' regulated asset bases (RAB). This is one of the reasons behind our proposed approach, which is a decentralised market-based model. We believe this ensures that the economic risks associated with provision of the services remains with those best placed to manage them.

We note that the current Rules allow for provision of the system services as proposed in TransGrid rule change proposal as unregulated transmission services. As such, network service providers are already able to offer these services to connecting generators that require provision of these services without the proposed rule change. In our view, TransGrid's proposed rule change severely limit the scope for a lowest cost solution by limiting the provision of system services to network service providers. If implemented, the rule change would transfer all investment risk from network service providers to consumers. It is also worth noting that should ERM Power's proposed PSSAS market be implemented, network service providers would be able to make offers for provision of PSSAS using non-regulated assets.

Ramping services

The concept of a market ancillary service to provide ramping services in the NEM is one that may likely take on greater importance as the nature of electricity generation shifts to a greater volume of variable renewable generation, and in particular, the steep gradient in the evening period associated with the ramp down of rooftop and grid connected solar generation. While we are somewhat unclear that amendments to the rules for the provision of a lower ramp rate service will be required, given the strong pricing signal already provided by the market floor price, it is less clear in our view that a sufficiently strong signal will exist for raise ramping services under the 5 minute settlement framework due to be implemented 1 October 2021. We expect that a market-based raise ramping ancillary service as opposed to a significant increase in the market price cap would deliver greater net benefits to the NEM over the long-term. As with our overall approach, a market-based approach is likely to be the most efficient way in which to deliver these services.

Our proposed RRAS contains much of the dispatch, pricing and bidding framework to the proposed PSSAS market design. AEMO would monitor the forecast provision of ramp rate capability in the immediate (one-hour) pre-dispatch timeframe. AEMO would wait for the last time available before dispatching RRAS based on offered time(s) to achieve provision of the service. For a generating unit, this would be the time required to start, synchronise and achieve minimum unit output, for a load it would be the time required to implement process changes to commence providing the service.

A generating unit with the capability to provide Ramp Rate Ancillary Services (RRAS) and PSSAS simultaneously, would only receive one settlement payment for the provision of both ancillary services based on their higher cost offer. Multiple payments would not be received for the provision of both services simultaneously by the same generating unit.

Although we believe it is appropriate to place an ancillary services market framework in place based on the reasonable probability the service may be required in the future, the decision to procure RRAS will remain subject to AEMO's judgement.

Appendix B contains a table summary of a potential market-based ramp rate ancillary service which has some similarity to the proposed PSSAS design.

In-market reserves

As made clear in the consultation paper, and through other work such as the Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP), increasing volumes of variable renewable energy (solar and wind) with zero short run marginal cost are displacing higher cost dispatchable generation. This can create a situation where sudden and unforecast changes in demand or supply can lead to sudden changes in frequency due to a lack of synchronous energy, though this relates primarily to Hydro Tasmania's synchronous services rule change and inertia. It also means that some, but not all plant, which has previously been self decommitted, may take some time to resynchronise with the grid and begin dispatching energy and will therefore be slow to respond to any sudden and unforecast needs in the market.

By maintaining the presence of dispatchable reserves in the market, there is scope for plant to ramp up as needed and additionally, depending on the type of plant, may also provide inertia in the market, thereby helping to slow the rate of change of frequency and keep the system stable.

An in-market reserve as proposed would allow the market operator to look ahead in some time frame to determine whether certain generators, who though their bids have indicated an intention to self decommit or not self commit, may be needed to keep dispatching energy in the market in order to provide these additional reserve and power system services. The fact that these services are interrelated demonstrates the importance of forming a cohesive response that recognises the linkages and interactions between different approaches.

Infigen and Delta Electricity's proposed rule changes would create a dynamic market for in-market reserves, which, in their view would incentivise generation to be available in advance based on AEMO's view of system reserve needs rather than just at times as signalled by market price outcomes as set out in pre-dispatch or the internal view of the respective market participant.

ERM Power struggles to see how this change would improve on the current information provisions or settings in the market. The existing information provision and market settings, including the high market price cap, the short-term projected assessment of system adequacy (STPASA) and pre-dispatch PASA (PDPASA) along with AEMO's declaration of lack or reserve (LOR) notifications, which includes flexibility for forecasting uncertainty, all of which provide signals in different times frames up to seven days in advance for capacity to be made available to the market. We have observed that generators and demand response providers do respond to indicators of tight supply-demand balance and make themselves available. As a last resort AEMO has the ability to intervene in the market to secure sufficient reserves via the use of a Clause 4.8.9 Direction or procurement of out of market reserves via the Reliability and Emergency Reserve Trader.

While the rule changes both propose that changes in potential demand outcomes and variable renewable generation output will become increasing challenging in the future, it needs to be understood that the current AEMO forecasts contained in the STPASA and pre-dispatch already include for such variations and the process for the declaration of LOR conditions also contains an additional forecasting uncertainty measure value which increases in value over future time periods. Though we agree that the value of generation associated with a credible contingency event may also change over time, the current design of the FCAS markets allows for variable procurement volume of FCAS reserves by AEMO to manage this risk. We are of the view that the variability factors as set out in the rule change requests are already well catered for in the market's short-term forecasting framework.

The current market design allows for decision making in the form of self-commitment and self-decommitment by the respective market participants. This market design feature ensures that economic risks associated with these decisions are borne by the market participant as opposed to a central commitment and decommitment market design where the risks of decisions made by the market operator are borne by consumers. Market participants have the ability to manage these risks through the financial contract markets where a generator receives a fixed price for the negotiated contract volume, regardless of spot market dispatch outcomes. The proposed in-market reserve rule changes would in our view result in a transfer of the economic risks with regards to such decisions onto consumers.

It is unclear in ERM Power's view, what Infigen and Delta Electricity's in-market reserves rule changes are then seeking to solve or how generators would respond. In essence, it appears to be an additional selective payment for some generators, or demand response providers, who are not bid as available or to become available, even though experience shows they tend to make themselves available when needed based on the existing market economic signals. ERM Power wonders how this may play out in practice – could generators actually remain unavailable for longer than they otherwise would to try to extract a higher price in the reserves market? Would generators seek to reserve some capacity for the reserves market instead of bidding this capacity for normal dispatch. Could this lead to lower volumes of contracts being made available, and therefore inadvertently push wholesale, and retail prices higher? It would seem to create a kind of limbo capacity market that is neither in-market through the usual processes nor out of the market (and in-RERT).

Also, as the proposed in-market reserves would be withheld from the normal dispatch process until deemed required by AEMO, we are concerned that at times of tighter, but not necessarily tight supply demand balance, the normal dispatch prices for energy could be artificially inflated by the need to retain these in-market reserves, resulting in higher costs to consumers.

We also consider that while the proposed rule changes may reduce the need for some RERT capacity, it would effectively lead to the same kind of capacity (availability) payments that the RERT framework provides. Consequently, we fail to see how this rule change as proposed would meet the National Electricity Objective (NEO).

Fast frequency response

ERM Power sees there is strong merit in implementing the proposed fast frequency response (very fast contingency FCAS) markets. While there is no urgent need for these markets now, the time it takes to design, implement and integrate these markets with the existing (and potentially changing) market ancillary services markets means that we consider there would be benefits to doing this now rather than waiting until it is past due. This would also provide participants with time to adapt their own systems and adjust strategies to participate. Very fast contingency FCAS could become an extremely useful tool in the future to help manage frequency deviations as the quantum of synchronous generation decreases resulting in a decrease in synchronous (real) inertia and a continued increase in the volume of inverter-based generation and load in the power system.

We believe a simple amendment to the design of the existing Market Ancillary Services as set out in Clause 3.11.2 to include the *very fast raise service* and the *very fast lower service* and inclusion of defined terms for these services in Chapter 10 of the Rules. AEMO would consult on and amend the *market ancillary services specification* to specify service provision requirements for these new market ancillary services following amendments to the rules. Cost recovery and settlement, and provisions in the Rules associated with the cumulative price threshold, the market price cap, market suspension, etc. for these new ancillary services would mirror that applied in the Rules to the existing fast, slow and delayed market ancillary services.

AEMO would monitor and provide updated forecasts to the market regarding the commencement of procurement of these new very fast contingency FCAS.

Frequency control services

Whilst the Commission has considered the provision of frequency control services, there remain a number of issues that need to receive greater consideration. The market ancillary services specification (MASS) remains unclear in a number of areas, in particular, the provisions in the MASS for regulations services do not specify what the enabled providers should provide. We believe that an overall holistic review of the MASS is warranted which considers all aspects in the MASS including provisions for regulation services to be provided by primary frequency response, a change that AEMO has been reluctant to even consider to date. To date, only piecemeal reviews of the MASS based on AEMO's stated objectives have occurred. We recommend that the Rules require that AEMO review the MASS in its entirety on a regular basis and that all areas of the MASS be open for consultation for this review in the initial first stage of the Rules consultation process. Unlike the Rules where participants may submit a Rule change for consideration, no such framework exists for participants to initiate a review of procedures, processes, guidelines, etc. controlled by AEMO.

We note that recent changes to FCAS procurement has improved frequency outcomes in the NEM. Most notably, increases in procurement for regulation services has resulted in improvements to frequency outcomes during normal operating conditions. We also believe that further review of the efficacy of AEMO systems in the delivery of regulation services in the NEM is warranted.

We also consider that there exists a misalignment of the frequency operating standard (FOS) as set by the NEM's Reliability Panel and AEMO's view of what level of power system frequency control is warranted. We believe there should be alignment of AEMO's view and the FOS with the Reliability Panel setting the standard for the level of frequency outcome requirements in the NEM.

We are supportive of further review by the Commission of the issues as set out in Appendix C to the Paper.

With regards to the frequency control for managing contingency events, we note that adjustment to out-of-date load relief values by AEMO has improved frequency response following a contingency event.

We believe further ongoing and regular review of load relief by AEMO is warranted. We also consider that review of the interaction between the provision of regulation and contingency FCAS is warranted with regards to the response of AEMO automated generator control (AGC) in dispatching regulation FCAS following a contingency event.

AEMO's report on the events of 25 August 2018 highlighted a shortcoming in the design of the contingency FCAS markets where a concentration of procurement of contingency FCAS and available operating reserve headroom is in a limited number of regions. In this case, reserve headroom primarily existed in South Australia and this outcome led to a subsequent trip of the Heywood interconnector following a loss of the Queensland to New South Wales (NSW) interconnector. It is our view that should the same system conditions present again, that even with mandatory primary frequency response implemented, underfrequency load shedding would still occur as limited reserve headroom existed on generators in Victoria and NSW at the time the event occurred. We note that AEMO has yet to finalise and implement their recommendation for the events, market incident report to more evenly distribute contingency FCAS procurement across multiple regions and recommend that this form part of the Commission's consideration under this rule change process.

We consider that the Commission should also review the future requirements for support of power system frequency following non-credible contingency or protected events. We believe that even following implementation of a market-based solution for the provision of primary frequency response (PFR), additional wide band frequency response from generators and loads not enabled for PFR is warranted. Amendments to Schedule S5.2.5.11 (Frequency control) are required to include mandatory wide range frequency response. We also believe that the Commission should consider as part of this rule change process what other forms of emergency frequency control schemes may be required for the future such as contracted underfrequency load shedding and over frequency generator runback/tripping schemes.

Conclusion

ERM Power welcomes the AEMC's decision to examine these six rule changes via a single consultation paper. It is important that these issues be considered together in order to develop a consistent and holistic response. We have considered these issues as a whole and developed proposed service provision models that we believe can address the challenges raised in the rule changes using market-based responses. Our proposed PSSAS model is likely to meet the aims of several of the rule changes using a least-cost, market-based response. The RRAS model is proposed to mitigate concerns that the current market design may be result in insufficient scheduled ramping capability to allow AEMO to manage the ramp down of rooftop and grid connected solar PV at some point in the future. We would welcome the opportunity to further work through these proposals with the Commission.

As set out in our submission we support Infigen's proposal to facilitate the early provision of a market framework for the provision of very fast contingency FCAS which Infigen refers to as fast frequency response.

We do not support the calls for the creation of in-market standing reserves as it is unclear that this is or will be required in the future given the existing information provisions and market settings.

Given the complexity and inter-related nature of the rule changes, along with the parallel, post-2025 review of the NEM process, we recommend that the AEMC take the time to move to a directions paper following this consultation, rather than straight to a draft determination. This will allow for a more comprehensive investigation of the relevant issues with stakeholders.

Yours sincerely,

[signed]

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Appendix A – Summary of Design Features of Proposed Power System Services Ancillary Services Market					
Service/Product	**Price Setting**	**Pricing**	**Generation/Provider Offers**	**Dispatch Method**	**Cost Recovery**
Energy – No Change	NEMDE	$/MWh Metered Output – No Change	No Change	No Change	No Change
FCAS – No Change	NEMDE	$/MW enabled – No Change	No Change	No Change	No Change
Power System Security Ancillary Services (PSSAS) – New Market Ancillary Service PSSAS includes the following PSS services Rate of Change of Frequency Management (Inertia) Voltage Control System Strength A provider could be dispatch for provision of one or all 3 services simultaneously if capable of doing so	NEMDE Dispatch in combination with NEMDE Pre-Dispatch forecast Co-optimised with Energy and FCAS markets dispatch Market Price Cap – set by Reliability Panel Initial Values Generating Unit = $500/MWh Non-Generating Unit = $250/Dispatch Interval Market Floor Price = $0	**Provision by Generating Unit** $/MWh differential between Energy RRP and offer price based on dispatched minimum load value. Above minimum load dispatch via Energy market bids Service provider settled on the basis of (offer price – RRP) x minimum load value x MLF **Provision by Non-Generating Unit Provider** $/Energy Market Dispatch Interval Service provider settled on the basis of (offer price x Dispatch Interval count	**Provision by Generating Unit** Confirmation of offer for PSSAS and services offered - voluntary Minimum load - MW Time to synchronise and achieve minimum loading - minutes Minimum and maximum time period for which the service is offered - minutes $/MWh to generate at minimum load – offered in positive priced band in Energy bid. Start Cost - only paid if generator not already in-service Normal price band offering in Energy market for loading above minimum loading. Provider able to offer FCAS if operation is within FCAS trapezium **Provision by Non-Generating Unit Provider** Confirmation of offer for PSSAS and services offered – voluntary Time to commence provision of the service - minutes Minimum and maximum time period for which the service is offered – minutes $/Energy Market Dispatch Interval for provision of service	Based on AEMO determination of power system requirements Dispatch based on AEMO's assessment of lowest cost provision for service co-optimised with Energy, FCAS and RRAS AEMO issues a dispatch instruction for time to achieve minimum loading and required time for end of provision of service	Regionally recovered based on overall costs incurred in the respective Trading Interval during the Settlement Billing Week based on 50% from Market Customers and 50% from Generators and BESS. Based on energy produced or consumed in those trading intervals where PSSAS was dispatched.

Appendix B – Summary of Design Features of Proposed Ramp Rate Ancillary Services Market					
Service/Product	**Price Setting**	**Pricing**	**Generation/Provider Offers**	**Dispatch Method**	**Cost Recovery**
Energy – No Change	NEMDE	$/MWh Metered Output – No Change	No Change	No Change	No Change
FCAS – No Change	NEMDE	$/MW enabled – No Change	No Change	No Change	No Change
Ramp Rate Ancillary Services (RRAS) – New Market Ancillary Service	NEMDE Dispatch in combination with NEMDE Pre-Dispatch forecast Co-optimised with Energy and FCAS markets dispatch Market Price Cap and Market Floor Price – set by Reliability Panel Initial Values Market Price Cap = $500/MWh Market Floor Price = $0/MWh	**Provision by Generating Unit** $/MWh differential between Energy RRP and offer price based on dispatched minimum load value. Above minimum load dispatch via Energy market bids Service provider settled on the basis of (offer price – RRP) x minimum load value x MLF **Provision by Demand Response Service Provider** $/MWh Service provider settled on the basis of (offer price x enabled load value MW x MLF	**Provision by Generating Unit** Confirmation of offer for PSSAS and services offered - voluntary Minimum load - MW Time to synchronise and achieve minimum loading - minutes Minimum and maximum time period for which the service is offered - minutes $/MWh to generate at minimum load – offered in positive priced band in Energy bid. Start Cost - only paid if generator not already in-service Normal price band offering in Energy market for loading above minimum loading. Provider able to offer FCAS if operation is within FCAS trapezium **Provision by Demand Response Service Provider** Confirmation of offer for PSSAS and services offered – voluntary Time to commence provision of the service - minutes Minimum and maximum time period for which the service is offered – minutes $/MWh of enabled load/Energy Market Dispatch Interval for provision of service Provision of service ceases if load is dispatched for demand response Provider able to offer FCAS is capable of provision of both services	Based on AEMO determination of power system requirements Dispatch based on AEMO's assessment of lowest cost provision for service co-optimised with Energy, FCAS and PSSAS AEMO issues a dispatch instruction for time to achieve minimum loading or capability to dispatch demand response and required time for end of provision of service	Regionally recovered based on overall costs incurred in the respective Trading Interval during the Settlement Billing Week based on 100% from Market Customers Based on energy consumed in those trading intervals where RRAS was dispatched.