AEMC

RULE CHANGE

Australian Energy Market Commission

CONSULTATION PAPER

National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule 2016

Rule Proponent(s)

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About the AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

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1 Introduction

On 30 March 2015, the COAG Energy Council (the Energy Council) submitted a Rule change request to the Australian Energy Market Commission (AEMC or Commission) that seeks to create a demand response mechanism (DRM) in the National Electricity Market (NEM) and to unbundle the provision of ancillary services from the purchase and sale of electricity.

The rule change request was submitted in response to the recommendations made by the AEMC in its Power of Choice review, completed in 2012.[1]The rule change request proposes a mechanism that would allow the demand side to participate in the wholesale spot market without requiring customers to become wholesale market participants or otherwise bid into the central dispatch system. A new class of market participants, demand response aggregators (DRAs), would self-schedule customer's demand response in the wholesale spot market.

A second part of this rule change request seeks to allow DRAs to aggregate and offer load into the ancillary services market in accordance with existing rules on ancillary services. This would have the effect of unbundling or separating the provision of ancillary services and demand side services from the purchase and sale of electricity.

Overall, this consultation paper seeks stakeholder feedback on both:

- The major issues that need to be considered by the Commission in assessing this rule change request given its significance and broad scope, affecting many areas of the National Electricity Rules. A preliminary review of the rule change request suggests that more than the six month standard rule making process will be required, particularly if the Commission reaches a view that there is a problem that a change in the rules could address. In this regard, stakeholder views on the major issues will inform the timetable and process for further considering this rule change request. Once submissions are received and considered, the Commission will notify stakeholders of the timeframes and the process that will be adopted for this rule change; and

- AEMO's detailed design proposal published in November 2013.[2]

In addition, to inform stakeholders and to assist the Commission's assessment of this rule change request, the Brattle Group was engaged to conduct an international review of demand response mechanisms to understand how demand side participation (DSP) has been organized in other electricity markets across the world.[3] Out of all the energy-only markets surveyed, only Singapore will be implementing a comparable

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1 AEMC, *Power of Choice review,* final report, AEMC, 30 November 2012, Sydney.

2 AEMO, Appendix B: Demand Response Mechanism and Ancillary Services Unbundling - Detailed Design, AEMO, 15 November 2013.

3 The Brattle Group, International Review of Demand Response Mechanisms, The Brattle Group, October 2015.

demand response mechanism. This report, published alongside this consultation paper, is available on the AEMC's website.[4]

This consultation paper:

- Sets out the background to, and summary of the rule change request;
- Sets out a proposed assessment framework to be used by the Commission in assessing the rule change request;
- Identifies a number of questions and issues to facilitate public consultation on the rule change request; and
- Outlines the process for making submissions.

Submissions to this consultation paper are due by no later than 10 December 2015.

4 See, http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

2 Background

2.1 Power of Choice recommendations and subsequent developments

The AEMC made recommendations in the Power of Choice review to the (then) Standing Council on Energy and Resources (now COAG Energy Council) to introduce a demand response mechanism (DRM) which would add to the existing suite of options available to customers, mainly commercial and industrial users, to manage their electricity demand. The final report also recommended that AEMO develop the details of a rule change and the supporting procedures associated with implementing the DRM and the unbundling of ancillary services.

In early 2013 the COAG Energy Council requested AEMO to develop, in consultation with stakeholders, a detailed design and a draft rule enabling the implementation of a DRM and the unbundling of ancillary services.

In December 2013, The COAG Energy Council requested AEMO to defer lodgement of the rule change due to a "change in market circumstances since the initiative was initially proposed",[5] and for officials to undertake a cost benefit analysis and to report back to Energy Ministers. This analysis was done by Oakley Greenwood[6] and aimed at understanding the merits of implementing a DRM considering the new market conditions. That analysis concluded that implementing a DRM could still deliver a net benefit going forward.

On this basis, the COAG Energy Council assessed there was merit in considering a DRM, based on a voluntary and staged approach and submitted the rule change request to the AEMC.

2.2 Demand side participation in the NEM

There are various ways in which demand side participation is currently possible in the electricity market. The proposed demand response mechanism would add, if implemented, to a broader set of DSP options in the NEM. Table 2.1 below provides an overview of the existing mechanisms for DSP in the context of the NEM:

5 See http://www.scer.gov.au/files/2013/12/SCER-Communique-DEC-2013-v.2.pdf

6 Oakley Greenwood, Cost-Benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, 9 December 2014

Table 2.1 Existing Mechanisms for Demand Side Participation in the NEM

	Energy Market	Ancillary Services (Frequency control)	Reliability and System Security	Network support services
Objective	Manage or mitigate the impact of the spot market price spikes	Balance supply and demand at short time scales to maintain system frequency	Provide an alternative to load shedding and curtailment	Provide an alternative to planned network augmentation, managing constraints or voltage support
Scope of economic Benefits	Private benefits	System-wide benefits		
Current mechanism	(1)Voluntary participation in market dispatch; (2) Voluntary exposure to the spot price; (3) Contracts between customers, retailers and third party service providers to reduce demand	Participation in the Frequency Control Ancillary Service (FCAS) markets	Reliability and Emergency Reserve Trader (RERT) Procedures	Actively supported by a range of regulatory incentives schemes and contractual requirements (e.g. Demand Management Incentive Scheme, Network Loading Control Ancillary Services)

Existing mechanisms that enable DSP by participants may be grouped into four broad categories depending on whether the participation is for the energy market, the ancillary service market, or to provide reliability and system security services or network support services.

In terms of mechanisms that allow DSP in the NEM, existing market arrangements allow energy users that become a market customer with a market load to nominate their loads to become scheduled and bid into the central dispatch system. Participation in central dispatch is voluntary and potentially costly so the uptake of this option appears to have been limited in the NEM.

In addition, customers may be willing to accept full or partial exposure to wholesale spot market prices. This can be done either by becoming a wholesale market customer or through contractual agreements with retailers. Customers may then undertake measures to manage their electricity use and limit this exposure, for example, they may engage with energy management experts.

Further, some retailers also offer commercial arrangements that reward customers for their willingness to reduce demand upon request by the retailer.[7] The retailer may reward the customer through lower retail tariff rates, arbitrage payments between the spot price and the applicable retail tariff rate, or an availability payment.[8]

These commercial arrangements are between retailers and their customers, and may potentially involve third party service providers such as demand response aggregators or energy management experts. They are private arrangements and not visible to the market. The market operator has no role in relation to them.

The current rule change proposal is to implement a DRM in the energy market that allowed demand reductions to be rewarded via the wholesale spot market without actually requiring customers providing the demand response to become market participants. Further, AEMO would play a key role in developing and managing the methodologies used to calculate demand reductions.

Mechanisms that enable DSP in the ancillary services market, or to provide reliability and system security services, often require the participation of the market operator because these services deliver system-wide benefits to all users. For example, due to the ‘public good’ nature of ancillary services, the market operator coordinates and pays for these services on behalf of all market participants. This is also true for network support services, where DSP can deliver system-wide benefits. For example, transmission network service providers (TNSPs) or distribution network service providers (DNSPs) may contract with customers to deliver network benefits relating to the transmission or distribution network systems.[9]

Further, “knock-on effects” capable of delivering benefits between mechanisms could also emerge. For example, greater demand response capability and capacity to manage wholesale spot price spikes might create a critical mass of demand response resources capable of participating at the same time in the provision of network support services. Customers providing demand response resources could then be rewarded (for example by network operators) for providing a system-wide network benefit. The provision of these types of network support services requires that the location and the timing of the load reduction be known to the system operator at or prior to dispatch.

Mechanisms might also distinguish between themselves through the time frame in which load is required to respond. For example, loads participating in the energy or ancillary services markets might be expected to respond within a very short time frame but will only be required to maintain the response for relatively short periods.

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7 These commercial arrangements are sometimes referred to as demand reduction contracts. Retailers may offer them as part of a demand response program.

8 For example, see Oakley Greenwood, The Impact of Late Rebidding on the Provision of Demand Response by Large Electricity Users in the NEM, Oakley Greenwood, 25 November 2014, Section 3, p 9.

9 In some jurisdictions, system operators procure demand response capacity using a capacity mechanism, generally referred to as a capacity market. Under this type of market design it can be argued that the market operator delivers system-wide benefits by coordinating entry/exit of capacity in the market, including demand response capacity.

Alternatively, customers whose loads provide network support services are often notified a day in advance.

Further, mechanisms might also differ regarding whether the location of load providing the service is relevant. For example, within the capability of interconnectors between regions, frequency control ancillary services (FCAS) are procured on a national basis. On some occasions, however, it is necessary to procure FCAS on a regional basis, especially where that region is islanded or at risk of islanding.

Alternatively, the benefits from DSP in the energy market are maximized when the location of a load is known prior to the market dispatch. This is because when prices are high, networks are likely to be congested. In order for a load to provide economic value and alleviate network constraints, the magnitude and location of its response should be factored into the market dispatch process.

Mechanisms for DSP might also differ in the way they are implemented. For example, a range of regulatory incentives exist on TNSPs and DNSPs to consider demand response as an alternative to planned network augmentation, managing constraints or voltage support. Similarly, the Reliability and Emergency Reserve Trader (RERT) establishes procedures to procure the availability of demand response capacity.[10]

2.3 International review of demand response mechanisms

AEMC has commissioned the Brattle Group to review how demand side participation is organized in six different jurisdictions across the world.[11] Three of the six markets reviewed follow an 'energy-only' market design (Singapore, Alberta and ERCOT), while the remaining markets incorporate a 'capacity mechanism' complementing their overall market design (PJM, ISO-NE and Ontario). Markets with a capacity mechanism are not directly comparable to the NEM. However, capacity mechanisms have been designed to integrate demand response resources so reviewing these markets may provide useful insights applicable to the NEM in the context of this rule change.

The report highlights that the energy-only markets studied have implemented very similar DSP options to the ones currently available in the NEM. For example, in Alberta and ERCOT customers can voluntarily bid their loads into the central dispatch system. Similarly to the NEM, the participation rate by loads in the central dispatch has been low in both jurisdictions. As noted in the report, while demand side bids would reduce reliance on the system operator's demand forecasts, the benefit to the market would come at a cost for loads as they would be subject to market rules, submit bids and follow market dispatch instructions.

Similarly to the NEM, the Alberta energy market operator determines both the real-time dispatch prices and the hourly settlement prices. In this jurisdiction, aligning

10 The RERT is due to expire on 30 June 2016.

11 The Brattle Group, International Review of Demand Response Mechanisms, The Brattle Group, October 2015.

dispatch and settlement periods – most likely through shorter settlement periods – is an outstanding policy issue since 2005 to address low DSP in market dispatch.[12]

At present, in Singapore, customers cannot bid their loads into the wholesale electricity market. However, a demand response mechanism is currently being introduced in the Singapore wholesale electricity market that will allow demand-side bidding. The mechanism to be used is similar to the one proposed in the rule change request for the NEM. It is implemented with the active participation of the market operator and the mechanism is aimed at mitigating the impact of spot market price spikes. Further, it also includes the creation of a new class of licence for demand response aggregators.

It is, however, different from the one proposed in the rule change request in important ways. Rather than the system operator implementing a baseline consumption methodology, in the Singapore mechanism, demand response aggregators will be required to bid their baseline demand into the central dispatch. Demand response aggregators could be penalized if energy consumption does not closely follow the baseline demand they bid in the event that the demand reduction is not dispatched.

The report also indicates that in energy-only markets, DSP in the ancillary service markets is not an exception. For example, load participation rates in ERCOT and in Alberta are higher with respect to other markets considered in the review.

The evolution of the design of the DSP programs in the capacity market jurisdictions has highlighted some useful insights. As stated in the report, treating demand response and generation resources equally has been debated widely and subject to litigation. For example, some of the debates relate to the economic inefficiency of paying the full market price to customers providing demand reductions.

The report also notes that the technical characteristics of demand response and generation resources are different. For example, generators are likely to be available year-round, while demand response resources availability is likely to be more seasonal.

2.4 Key changes since the publication of the Power of Choice review final report

This rule change request is part of a broader package of reforms to support greater DSP in the NEM which was recommended in the Power of Choice review. In addition to this DRM rule change request the AEMC also made a number of other recommendations to facilitate more efficient demand side participation in the NEM, including the areas of information, education, technology and flexible pricing options. The Energy Council agreed to implement the majority of the recommendations made by the AEMC in the Power of Choice review. Four of the rule change requests coming out of that review that are relevant to the DRM rule change request are summarised below:

12 The Brattle Group, International review of Demand Response Mechanisms, The Brattle Group, October 2015, p 36.

- **Distribution Network Pricing Arrangements:**[13] The AEMC made new rules that require distribution network service providers to develop prices that better reflect the costs of providing services to individual consumers. The structure of network prices will be consulted on, developed and approved as part of a Tariff Structure Statement (TSS). Overall, these changes should aid consumers to make more informed choices about how they use electricity and assist them to participate more actively in the energy market. The rule determination was published on 27 November 2014The final determination laid out new rules that require distribution network businesses to develop prices that better reflect the costs of providing services to individual consumers. The aim is to assist DSP in the NEM, and builds on the existing incentive-based network regulation framework. Network businesses will have to consider how to differentiate network prices applicable to individual customers and, at the same time, recover the total amount of allowed revenue under the price control. The structure of network prices will be consulted on, developed and approved as part of a Tariff Structure Statement (TSS). Overall, these changes should aid consumers to make more informed choices about how they use electricity and assist them to participate more actively in the energy market;

- **Improving demand side participation information provided to AEMO by registered participants**:[14] The AEMC made a final rule on 26 March 2015, providing a process by which AEMO may obtain information on DSP from registered participants in the NEM. The final rule, which is a more preferable rule, requires registered participants to provide AEMO information on DSP, in accordance with the guidelines that were developed by AEMO in consultation with stakeholders. AEMO must take into account that information when developing or using load forecasts. This rule change may impact on the quality of AEMO's load forecasts, from short term forecasts such as 5 minute pre-dispatch, to long term forecasts such as the ten year forecasts in the National Electricity Forecasting Report;

- **Expanding competition in metering and related services:**[15] The current draft rule is aimed at facilitating a market-led approach to the deployment of advanced meters where consumers drive the uptake of technology through their choice of products and services. This framework is expected to promote innovation and lead to investment in advanced meters that deliver services that are valued by consumers. While under the draft rule consumers with an advanced meter would not be required to switch away from their current retail tariff, it would create greater opportunities for consumers to better understand and take control of how they use electricity and the costs associated with their usage decisions. Further, advanced meters may provide retailers and DNSPs the opportunity to access services that support the efficient operation of the

13 See, http://www.aemc.gov.au/Rule-Changes/Distribution-Network-Pricing-Arrangements

14 See, http://www.aemc.gov.au/Rule-Changes/Improving-Demand-Side-Participation-information-pr

15 See, http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

electricity system, allowing them to provide lower cost and higher quality services to consumers. A final rule determination and final rule will be published on 26 November 2015;

- **Multiple Trading Relationships (MTR):**[16] The AEMO submitted a rule change request to the AEMC that is designed to reduce costs and make it easier for customers wanting to engage with more than one electricity retailer at a customer's premises. This may include a customer engaging two retailers, one for general supply of electricity and another for the supply to a specific appliance, such as an air conditioning unit. AEMO argued that these kinds of arrangements may foster competition in the electricity retail market and the delivery of more innovative products to consumers; as well as supporting more innovative ways for greater DSP in the energy market. The Commission is currently preparing a draft rule determination in respect of this rule change request. It will be published on 19 November 2015.

16 See, http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships

3 Details of the rule change request

This chapter summarises the COAG Energy Council's (the Energy Council) rule change request, including:

- The issues the Energy Council raises in relation to current market arrangements;
- A brief overview of the rule change request. A more detailed description is provided in chapters 5 and 6; and
- The Energy Council's view on how the proposed changes are likely to promote the National Electricity Objective.

3.1 Issues the COAG Energy Council raises in relation to current arrangements

There are a range of issues that the Energy Council identifies with the current electricity market arrangements that result in:

- Barriers to demand side participation; and
- Demand not being treated similarly to generation in the wholesale market.

These are explained immediately below.

3.1.1 Barriers to demand side participation

The Energy Council identifies a series of barriers to demand side participation in the NEM.

Firstly, under current arrangements large customers have two options to choose from to be exposed to the wholesale spot price. Either they buy electricity directly from the wholesale spot market by becoming a registered participant themselves, or they bear a degree of wholesale spot price exposure through contractual arrangements with their retailer. Both these options imply incurring costs to monitor and manage exposure to wholesale spot price risk. The Energy Council identifies these costs as being greater than the potential benefits of being exposed to the wholesale spot price risk resulting in customers' not choosing these options.

Secondly, retailers argue that most customers are happy for their retailer to manage their wholesale spot market price exposure but that retailers offer demand response arrangements to customers as part of their contract offerings. However, the Energy Council notes that in their responses[17] to the Oakley Greenwood cost-benefit

17 Major Energy Users Inc's submission to the Oakley Greenwood Cost-Benefit Analysis consultation paper.

analysis,[18] large customers argued that retailers lack incentives to induce customers to reduce demand because retailing is a volume driven business. Further the Energy Council argues that retailers have an incentive to limit demand response because it reduces the wholesale spot price risk they manage on behalf of their customers for which they get a reward in the retail market. So, unless demand response delivers a greater reward than selling energy, the retailer will not be active in this area.

Thirdly, large users have also reported that the terms offered on demand response contracts are generally not attractive, and they are rarely called upon when the wholesale spot market price is above the contract's strike price. In addition, it is the retailer calling the demand response rather than the customer making demand response an option to the retailer. Given that large customers cannot be sure that they will be called upon, this limits their appetite to agree demand response contracts especially when an investment is required.[19]

3.1.2 Treating demand in a similar way to supply in the wholesale spot market

The Energy Council argues that the current operation of the spot market has a bias towards the supply side in setting the spot price. This is because generators' bids determine the spot price, but consumers are not given the option to change their demand in response to the likely costs of supply as they do not experience any time-based wholesale spot price signal.[20]

In the Energy Council’s view, given the limited opportunities of end use customers to respond to wholesale spot price signals, demand reductions are not valued in the wholesale spot market in the same way as supply side resources.

Overall, the Energy Council considers that this limits the ability of the demand side to compete with generators to offer the most efficient option to balance the market and minimise wholesale costs for all users through greater market competition and the potential for deferring investment in peak generation.

3.1.3 Competition in the ancillary services market

The rule change request seeks to address a lack of competition in the provision of ancillary services, which are currently bundled with the purchase and sale of electricity in the spot market. It is argued that this limits competition and diversity of supply for these services to those market participants that purchase and sell electricity in the spot market.

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18 Oakley Greenwood, Cost-Benefit analysis of a possible Demand Response Mechanism, Oakley Greenwood, 9 December 2014.

19 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 4.

20 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 5.

Additionally, while it is possible to aggregate load to provide ancillary services, currently this can only be done by the same set of market participants. As such, the provision of ancillary services in the wholesale spot market is currently limited to generators and those customers registered in the wholesale spot market with large loads that can respond quickly such as aluminium smelters and pumped hydro.[21]

3.2 Overview of the COAG Energy Council's proposed solution

The objective of the proposed rule change would be to enable the demand side to compete with generation resources in balancing demand and supply in both the wholesale spot and ancillary services markets. If implemented, the proposed rule would allow large customers to participate in a DRM without being registered as participants in the wholesale spot market.

The rule change would also unbundle the provision of ancillary services from the purchase and sale of electricity which the Energy Council states has limited competition and diversity of supply for these services. This would address what the Energy Council refers to as a lack of competition in the ancillary services market.[22]

Both proposals are explained in detail in chapters 6 and 7, respectively. In this chapter we provide a brief summary of the two different components of the Energy Council's rule change proposal.

3.2.1 Summary of the demand response mechanism design proposal

This section provides a brief summary of the demand response mechanism (DRM) proposal:[23]

- Demand response aggregators (DRAs) would be created as a new class of market participant in the wholesale spot market;
- DRAs would establish commercial arrangements with customers that have responsive loads to provide demand response services;
- AEMO would implement a baseline calculation methodology (BCM) to be used to calculate the consumption that would have occurred in the absence of demand response;
- The DRA would initiate a demand response event and would notify AEMO of a demand response interval;

21 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 5.

22 COAG Energy Council, Demand Response Mechanism Rule Change Request, COAG Energy Council, 8 April 2015, p 3.

23 No formal draft rule was provided.

- The demand response is taken to be the difference between baseline and actual metered consumption during the demand response event;

- The retailer would be settled and charged for the baseline energy consumption during a demand response event;

- The DRA would be settled and paid the spot price for demand response that occurred during the demand response event. The DRA would pay the spot price for any metered energy consumption that exceeds the baseline energy; and

- The DRA would have commercial agreements to share the demand response payments with its customers.

The DRM is proposed to be implemented in the following way:

- DRAs would self-schedule demand response and facilitate large energy users to act as though they were non-scheduled generators to maintain the flexibility of the customer to respond to short term demand peaks and to treat load reduction in a manner consistent with unscheduled generation;

- Initially, only large customers, as defined in the National Energy Customer Framework, would be eligible to access the DRM, subject to meeting technical and load predictability requirements. Smaller customers may participate in the future;

- A voluntary approach is proposed, where retailers could choose whether to enable their customers to offer demand response either through becoming a DRA themselves or allowing their customers to work through another DRA. Billing arrangements would only be affected for those customers who participate in the DRM; and

- A staged implementation approach is proposed, where retailers would not be required to have all systems in place for the commencement of the DRM rule change but could use some manual work around.

3.2.2 Summary of ancillary services unbundling proposal

This section provides a brief summary of the ancillary services unbundling (ASU) proposal:

- DRAs would be created as a new market participant in the wholesale spot market. The creation of the DRA role would effectively unbundle the provision of ancillary services and demand response services from the purchase and sale of electricity in the wholesale spot market;

- The DRA will be able to provide specialist support to customers who provide FCAS;

- Loads may be aggregated by DRAs and offered into the FCAS markets;

- Loads must meet the current technical requirements for proving ancillary services; and

- DRAs must comply with existing FCAS procedures, including conditions on accrediting ancillary services load.

3.3 The COAG Energy Council's assessment of how the changes would promote the National Electricity Objective

The Energy Council considers that the proposed rule change would allow meeting demand at a lower cost and introduce greater competition in the spot market. This would result in lower prices and a more reliable supply to consumers, and so further the NEO. In particular, the Energy Council notes that:

- Large users would be rewarded for their efforts to reduce demand at times when the market values it more, and have more options to manage their electricity costs resulting in a more efficient use of energy resources;

- Load offered in the DRM would compete with peaking generation plants to meet demand, resulting in a lower cost and a more efficient option to balance supply and demand and reduced ability for participants to exercise market power, resulting in lower prices for electricity and a more reliable supply for consumers;

- While in a market with oversupply of generation compared to demand forecasts it would be difficult for the DRM to defer investment in generation, this will not be the case in the future if the market moves towards tighter supply conditions where the DRM would provide a more cost-effective option to balance demand and supply;

- Encouraging investment in demand response capabilities might have knock-on effects in other markets. For example, customers with a demand response capability in the spot market might be more able to participate in network demand response programs, putting downward pressure on network charges;

- Unbundling ancillary services will result in a greater variety of potential suppliers, helping to support the reliability and stability of the system; and

- DRM will encourage innovation on a range of energy services for consumers, including energy advice and demand response services.

4 Assessment Framework

4.1 Requirements under National Electricity Law

The AEMC must assess proposed changes to the NER based on whether the proposed rule will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO) as set out under section 7 of the National Electricity Law (NEL). The NEO states that:

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

4.2 Proposed assessment framework

An approach for assessing whether the proposed rule will, or is likely to, promote the NEO is set out below. Stakeholder feedback on this part of the consultation paper is welcomed.

The relevant aspects of the NEO to this rule change are the "efficient investment in, and efficient operation and use" of electricity services "with respect to price, quality... reliability and security of supply of electricity". It is proposed that the Commission will assess whether the proposed rule change would be likely to:

- Assist in determining the lowest cost dispatch of scheduled electricity load, generation and ancillary services in order to balance supply and demand;
- Incentivise electricity users to make decisions to use electricity at times when the value of its use exceeds its underlying cost;
- Send better signals to market participants to invest and maintain the electricity system; and
- Result in system wide costs and/or benefits that may impact the cost of electricity services and/or the security and reliability of market supply.

To understand whether the proposed rule change is likely to pass the rule making test a framework to assess the impact of the rule change based on the following factors is proposed:

- Whether the proposed rule would result in improvements to the market price signal;

- Whether the barriers to DSP identified here and any others raised are efficiently addressed;
- Whether the costs and benefits are allocated to parties that are best able to manage them; and
- Consideration of resulting of system-wide costs and benefits.

These factors are explained below.

4.2.1 Improvements to the market price signal

Efficient market price signal reflects either supply and demand conditions regardless of how quickly or frequently these conditions change. On the supply side this may include underlying information relating to, for example, production costs, whereas on the demand side it may include underlying information relating to how consumers' value the use of electricity or their ability and willingness to respond to prices. Improved supply and demand side information, coupled with an effective competition process, enhances the operation of the market and the efficient investment in and use of energy services, including demand response mechanisms.

Therefore, a consideration is whether the rule change is likely to facilitate improvements in market price signals due to the incorporation of demand side information, and the impact on the market's competitive process:

- **Incorporating demand side information**: whether the rule change would allow new demand side information to be efficiently incorporated into the spot price determination process in a way that:
  1. Allows wholesale market participants to react to new demand side information and update their strategies.
  2. The total cost of the resource mix dispatched to balance supply and demand in the ancillary services and energy markets, while taking into account possible network constraints, is a better reflection of the value of electricity use.
  3. Determines a wholesale spot price that more closely reveals the value that consumers place on an additional unit of generation capacity so that the market provides improved incentives for long term investment decisions in new generation capacity and consumers pay no more than necessary for their electricity.
- **Impact on the market's competitive process**: Whether the DRM mechanism design could establish and maintain a level playing field between competing technologies for generation and demand response resources to balance supply and demand in peak time periods, in a way that avoids the risk of the mechanism biasing the market's technology choices and displacing more efficient technologies for less efficient ones.

4.2.2 Addressing barriers to demand side participation in the context of this rule change

In the NEM, consumers already have a variety of demand response tools available to allow them to consume electricity only when the value of its use exceeds the cost of its supply. Barriers to demand side participation restrict consumers from using these tools, and prevent them from revealing demand side information to the market. As a result, consumers may be using electricity at times when the value of its use is less than the cost of its supply. Further, the existence of barriers to demand side participation might restrict the set of tools available to market participants to manage wholesale spot price risk and thus may impact on the efficient operation of, and investment in, the NEM.

In addition, consumers have the ability to consume in certain ways that might provide value in markets such as the ancillary services markets. Barriers to demand side participation in the ancillary services market prevent consumers from realizing this value and may restrict the NEM's ability to balance supply and demand at the lowest possible cost.

The proposed rule seeks to address barriers, which in the Energy Council's view, prevent demand side participation in energy and ancillary service markets. It is proposed that an assessment be undertaken of the following:

- The nature and significance of the barriers to demand side participation in the energy and ancillary services markets;
- Whether there are changes underway in the market that might mitigate or enhance the existing barriers or create new ones;
- Whether addressing any relevant barriers creates significant risks of unintended consequences, the costs of which will ultimately be borne by consumers; and
- Whether the potential benefits from addressing any identified barriers are proportionate to the costs.

4.2.3 Allocating costs and benefits to parties that are best able to manage them

It is proposed to consider how the costs and benefits of the proposed rule are allocated. This will also involve looking at the extent to which costs would be incurred by those participants who can best control and manage them.

4.2.4 Existence of system-wide costs and benefits

The proposed rule change may result in system-wide costs and benefits that could impact the costs of electricity services or the security and reliability of supply more generally. An assessment might consider, for example, the likelihood of positive or negative impacts on distribution and transmission networks or on AEMO's ability to manage the system's security and reliability.

Question 1 Assessment Framework

1. **Would the proposed framework allow the Commission to appropriately assess whether the rule change request can meet the rule making test?**

2. **What changes to the proposed assessment framework would stakeholders' consider appropriate, if any?**

5 Consultation issues on the Demand Response Mechanism

Taking into consideration the proposed assessment framework in chapter 4, an initial view of the potential barriers to demand side participation in the context of this rule change request is presented in section 5.1. The objective is to consult with stakeholders on their views in relation to the barriers, if any, that might continue to prevent customers and retailers from entering into efficient demand reduction contracts, and how best to address any identified barrier.

Section 5.2 presents the key design elements of the DRM proposal in some detail. The objective is to understand stakeholder's views on the detailed DRM design put forward by the proponent based on AEMO's detailed design proposal.

We note that the rule change request also proposes to unbundle the provision of ancillary services from the purchasing and selling of electricity in the wholesale spot market. While this is an integral part of the proposal, given the stand-alone nature of this element of the rule change request, this is addressed separately in chapter 6.

The matters outlined below and in chapter 6 are provided for guidance. Stakeholders are encouraged to make submission to the AEMC on these issues, as well as any other relevant aspects of the rule change.

5.1 Potential barriers to demand side participation

Currently, customers can and do avoid wholesale spot price risk by selecting a flat retail tariff structure[24] while the retailer manages this risk on their behalf for a premium. While these customers will not necessarily react to wholesale spot price movements, as set out in the background chapter, a mechanism already exists in the NEM which provides them with incentives to respond to spot price spikes.

This mechanism is contractual and sits outside the wholesale spot market, – sometimes referred to as a demand reduction contract. This contract exists between a retailer and a customer, and sometimes a third-party such as a demand side aggregator or an energy management expert. Under this contractual arrangement, the customer agrees to reduce load upon notification by the retailer in return for a benefit. The retailer gains an additional tool to manage the costs of spot price spikes, and can share any cost savings from the customer's agreement to reduce load with the end customer. Typically, the customer is rewarded for reducing load either with a lower electricity retail price, an arbitrage payment between the spot price and the customer's retail price - this is similar to the mechanism being proposed - or an availability payment.

This section discusses some of the potential barriers to DSP that may prevent the development of demand response as contemplated in this rule change request in the NEM. Some identified barriers lie in the retail market and others relate to the wholesale

24 With a flat retail tariff structure the customer pays a fix retail price for their electricity consumption.

spot market. Additional barriers may relate to the way in which instruments that enable retailers to manage wholesale spot price risk have developed in the current regulatory context.

5.1.1 Potential barriers relating to the retail market

A retailer looking to sign contracts for load reduction with its customers as a tool to manage spot price exposure will invest time and effort to identify and inform customers about the opportunities to reduce demand.

For example, it may be necessary to understand a customer's typical load profile, identify conditions under which loads may be turned-off, and engage with key operational staff to find out whether the rewards of reducing load are greater than the operational risks. These activities might not necessarily fall within the core business or expertise of the retailer or the customer, who may have to contract the services of a demand response aggregator or an energy management expert.

Therefore, investing and coordinating a critical number of customers to develop their load reduction capability may be costly to a retailer, especially when those investment costs are sunk and the customer has the opportunity to switch retailers.

As a result, retailers may be reluctant to invest time and effort to negotiate these contracts, or may only target a small group of customers who represent the 'low hanging fruit' of demand response contracts. Although the risk of customer switching could be mitigated by increasing the contract length, customers may be reluctant to lock-in their electricity supply with a retailer for a longer time period.

5.1.2 Potential barriers relating to wholesale spot price risk management

Retailers use a number of tools to manage spot price risks. These include:

- Buying their own generation assets, i.e. pursuing a vertical integration hedging strategy;
- Engaging in the financial market and purchasing electricity derivatives to hedge their wholesale spot price exposure; and/or
- Offering demand and/or peak based tariffs and/or demand reduction contracts to their customers to reduce demand during price spikes.

It is expected that the retailer will select a portfolio of instruments that most cost-effectively manages this risk. This allows the retailer to remain competitive in the market and offer competitive retail tariff structures to its customers.

A retailer that owns generation assets - commonly referred to as a "gentailer" - has an effective hedging instrument to mitigate wholesale spot price risk. When wholesale spot prices are high the revenue earned from electricity generation compensates for the negative margin from selling electricity on its retail tariffs. Conversely, when wholesale spot prices are low the margin included in retail tariffs compensates for the lower revenues obtained in generation.

Both standardised and tailored electricity derivatives and other electricity wholesale spot price hedging contracts are available through organised exchanges and over-the-counter markets. These financial products are quite popular and in general well understood by market participants. Overall, these financial derivatives are common and reliable instruments available to retailers in most NEM regions to manage their wholesale spot price risk exposure. Some derivatives have evolved over time to address common challenges for retailers in offering retail tariffs (e.g. peak and base load options and futures that map into time-of-use tariff contracts).

Alternatively, a retailer may engage with its customers and use demand response tools to manage wholesale spot price risk. While this may be effective in reducing demand during price spikes, it is not necessarily as reliable for managing wholesale spot price risks.

For example, the customer might be unable or unwilling to provide a firm commitment to reduce load at the retailer's preferred time. As a result, a retailer may need to over-procure load curtailment capacity in order to guarantee a level of demand response that sufficiently mitigates the impact of wholesale spot price risk. A retailer seeking to use demand reduction contracts to manage wholesale spot price risk may have to incur this additional cost to ensure that a sufficient firm level of demand reduction capacity is committed in periods where wholesale spot prices are likely to spike.

Furthermore, whereas derivatives contracts may be re-sold if conditions change, a retailer’s investment in demand reduction capability and capacity at the customer’s end cannot be traded among retailers.

5.1.3 Potential barriers relating to the wholesale spot market

Under the rules, the wholesale spot market settlement price for a particular trading interval is a 30-minute average of the six 5-minute dispatch prices that occurred during the relevant 30-minute trading interval. As a result, for a retailer – and indeed for any party exposed to the wholesale spot price - there could be a disconnect between the real time 5-minute dispatch prices that customers may be able to respond to, and the actual price at which the retailer is settled for the energy used by its customers.

It will be important to understand retailers’ incentives to rely on demand reduction contracts for the purposes of managing wholesale spot price risk and what would be required in order for them to use such contracts. Most importantly, the continuous averaging of the 5-minute dispatch prices across the 30-minute settlement period weakens the price signal at which the retailer would notify the customer to respond to when wholesale spot price spikes occur. Dampened wholesale spot price signals would tend to reduce the value that the retailer can derive and share with the customer from relying on demand reductions as an instrument to manage wholesale spot price risk.

Question 2 Potential barriers to demand side participation relevant to this rule change request

1. **What are stakeholders' views on the potential barriers to demand side participation that have been set out in this consultation document? How relevant might they be? Should they be considered in the Commission's assessment?**

2. **Have stakeholders identified other barriers to DSP that should be considered in the Commission's assessment? Please, explain and provide evidence where possible**

3. **What are the costs and benefits of removing the barriers that are identified as significant to this rule change request? Which barriers are the most problematic and/or more cost-effective to remove?**

4. **Are there any current or upcoming changes in the market that would mitigate or address any of the identified barriers?**

5. **Might there be any unintended consequences from addressing such barriers?**

5.2 The proposed demand response mechanism

The following section describes the key features of the proposed DRM as set out in AEMO's detailed design document[25] included in the COAG Energy Council's rule change request. So that the specific design features are accurately captured, the important elements of the description and the terminology used by AEMO in its detailed design are retained.

The Commission invites comments on any aspect of the detailed design detailed presented in the following section or in AEMO's detailed design document. In addition, the following questions on the overall aspects of the proposed design are put forward for consultation with stakeholders:

Question 3 Questions on the overall DRM design proposal

1. **Would the proposed DRM generate useful demand-side information in relation to improving wholesale pre-dispatch and dispatch prices? How significant would this improvement be?**

2. **Would the proposed DRM generate useful demand-side information in relation to improving the management of transmission constraints**

25 AEMO, Appendix B: Demand response Mechanism and Ancillary Services Unbundling - Detailed Design, AEMO, 15 November 2013.

through the dispatch process? How significant would this improvement be?

3. **Would the proposed DRM generate useful demand-side information in relation to improving the provision or procurement of ancillary services? How significant would this improvement be?**

4. **Would the proposed DRM operation result in a technology neutral approach between demand response and generation resources?**

5. **Do stakeholders think that there exist any relevant gaming risks or unintended consequences from implementing the overall proposed DRM operation? If so, how could they be mitigated in a cost-effective way?**

6. **Would the DRM result in system-wide benefits and/or costs that might impact the operation and investment in electricity transmission and distribution networks? What aspects of the design would contribute to this?**

7. **Would the DRM result in improved ability for AEMO to manage system security and reliability? What aspects of the design would contribute to this?**

5.2.1 A new class of market participant - A Demand response aggregator

The proposed rule would create a new class of market participant, a Demand Response Aggregator (DRA):

- Any existing market participant and new specialist aggregators would be able to register as a DRA;
- A DRA would be able to make commercial arrangements with parties who have demand response loads (DRL) to reduce their energy consumption during demand response events;
- A DRA could self-schedule demand response events via the DRM and be paid at the relevant regional spot price for this response;
- Only market participants registered as DRAs would be able to nominate demand response events via the DRM.

5.2.2 The end user - Demand response load

A demand response load (DRL) would be an end user that provides demand response to a DRA:

- DRLs would not directly participate in the wholesale spot market but rather through contractual arrangements with DRAs;

- Demand response could be provided by, for example, shutting down industrial processes for a period of time or through energy conservation measures;
- Demand response energy provided by a DRL would be associated with a single national metering identifier (NMI) with all calculations of demand response energy performed with respect to that particular NMI.

Participation in the DRM would only apply to loads that have been accredited and classified with AEMO as demand response loads (DRLs). There would be further eligibility requirements for DRLs. These include that the load would be:

- Large (consumption typically over 100 MWh per annum);
- Measured at the level of individual NMIs;
- Measured with metering installation type 1, 2, 3 or 4, which can provide half hourly daily settlement data; and
- Predictable within an acceptable tolerance with the methods used to calculate baseline energy.

There would also be restrictions on how demand response could be sold to the market:

- A DRA could not take on the role of DRA for a NMI if the end user has generation measured at that NMI which was sold as generation to the NEM via a market generator or market small generation aggregator. However, if the generation is not sold to the NEM as generation then the DRA could take on the DRA role for the NMI;
- A DRA could not take on the role of DRA for a NMI if the end user at that load is classified as a scheduled load by a retailer or an ancillary service load by a retailer or another DRA; and
- It will be the responsibility of the DRA to establish compliance of its DRL customers with all relevant restrictions and to ensure that the DRL is able to comply with any relevant demand response notification at all times;

5.2.3 Payments and energy settlements in the DRM

The DRA would self-schedule demand response in the DRM, and would be paid the half hour wholesale energy spot price in the region for the demand response energy. AEMO would determine the demand response energy provided based on the difference between baseline energy - what demand would have been for the NMI without demand response - and the actual metered load of the NMI (Further details can be found in Section 5.2.5). However, the DRA would also be charged at the half hour regional wholesale energy spot price if actual energy consumption exceeds the baseline energy during the demand response event.

During the demand response event, the retailer for the NMI would be settled based on the baseline energy and would be allowed to charge the end user as if it had consumed the baseline energy. As stipulated in their commercial arrangements, the DRA would share the payments received in the NEM with the customer.

The DRA would have financial responsibilities associated with this role. However it is not proposed that the DRA would be treated as a Financially Responsible Market Participant (FRMP) as currently defined in the Rules. The DRA would be financially accountable in relation to the demand response energy during demand response events, while the FRMP would remain financially responsible for the sum of the metered energy (outside of demand response events) and demand response (baseline) energy (during demand response events).

5.2.4 Demand response notification to AEMO

Any time the DRA self-schedules a demand response, it would be required to submit a Demand Response Notification (DRN) to AEMO. When AEMO receives a DRN it would publish it, as soon as possible, through the wholesale Electricity Market Management System (EMMS) and its website as public notification. The notification would contain the following information:

- The demand response start date and trading interval;
- The demand response end date and trading interval;
- The region; and
- The list of NMIs providing demand response and the transmission node identity (TNI).

Procedural requirements relating to valid notifications submitted by DRAs would include:

- That the start of the demand response event would be no earlier than the start of the trading interval during which AEMO received a notification and no later than 24hrs after the submission time of the notification. If a demand interval crosses multiple intervals, up to the maximum of consecutive 24 hours, then the notification would be first provided before the end of the first affected trading interval;
- A DRA would be able to provide, change or cancel a notification at any time up to the end of an affected demand response interval; and
- Changes to the expected duration of the demand response interval would have to be submitted before the end of the last trading interval included in both the original and revised notification.

5.2.5 Accredited baseline consumption methodologies

Initially, AEMO would develop and accredit two baseline consumption methodologies (BCM), one relating to the baseline when the demand response occurs on a weekday and another baseline when it occurs during a weekend or public holiday.

BCMs could be specified by a range of components including the baseline window, the exclusion rules, the baseline calculation type, the baseline adjustment, and the adjustment window. These components would be compiled using simple mathematics and data drawn from recent qualifying days:

- **Baseline window:** This would be the period of time preceding a demand response event from which meter data would be used for the purpose of establishing a baseline. Examples of baseline windows include the last 45 calendar days or the last 10 non-holiday weekdays;

- **Exclusion rules:** These are the rules for excluding data from the baseline window. For example, these rules would exclude days (or trading periods) with previous demand response events or days with the highest or lowest loads;

- **Baseline calculation type:** This would be the method of developing the baseline value using data from the baseline window. For the proposed BCM simple averages would be used to calculate a baseline value;

- **Baseline adjustment:** The baseline adjustment would be an additional calculation applied after the basic calculation type, to align the baseline with observed conditions of the event day. The basic calculation type would be applied to an adjustment window. In the proposed BCM an additive approach to baseline adjustment would be implemented. The adjustment would be based on the average difference between the baseline and actual data for the adjustment period. The average difference would then be added to the baseline during the demand response interval; and

- **Adjustment window**: The adjustment window would be the period of time before the demand response occurred, for which actual meter data is available. For example, the first 3 hours of the 4 hours prior to the demand response.

The DRA would be able choose a BCM combination for each of its DRLs. As a result, when taking the role of a DRA for a NMI, a DRA would be able to select one of the following accredited BCM combinations:

- **BCM combination 1**: This combination will consist of two BCMs. A first BCM to calculate the baseline when demand response occurs on a weekday, and an alternative BCM for when the demand response occurred on weekends or public holidays; and

- **BCM combination 2**: This combination will consist of just one BCM for when demand response occurs on a weekday only. This BCM combination could be used when a demand responsive load fails the predictability test for weekend days only. In this case, the demand responsive load would not be allowed to participate in the DRM on weekend days.

Procedures would be developed to review, assess, and confirm the performance of the accredited and newly proposed BCMs and BCM combinations. A review of the accredited BCM and their combinations would require significant analysis and should not be attempted frequently. Changes stemming from the review are implemented via the procedure change process so as to allow an appropriate level of consultation and impact assessment.

An expedited process is proposed in the event of a significant material problem being identified and requiring remedy.

The procedures would specify the following assessment criteria to be applied when assessing baseline consumption methods:

- Accuracy – how closely a baseline consumption methodology predicts customers' actual loads in the sample;
- Bias – the systematic tendency of a baseline consumption methodology to over- or under-predict actual loads;
- Variability – the measure of how well the baseline consumption methodology is at predicting hourly load under many different conditions and across many different customers;
- Ease of explanation – the transparency of and ability to explain the baseline consumption methodology to program participants; and
- Implementation and operating costs – the associated level of investment in activities such as data transfer, data quality review, analysis, training, and IT systems requirements.

Question 4 Accredited baseline consumption methodologies

1. **In stakeholders' views, are there any alternative demand response mechanism options that would not require the use of baseline consumption methodologies?**
2. **What might be the costs, benefits, and consequences from having an administrative baseline developed and then managed by AEMO?**
3. **What are stakeholders' views on the proposed baseline methodologies, and the proposed assessment criteria to be applied when assessing baseline consumption methods?**

5.2.6 Restrictions on the provision of demand response

A DRA would be prohibited from including a NMI in a demand response notification where:

- The customer has, for the sole purpose of influencing the calculations of the baseline energy, artificially inflated historical usage or biased the selection of qualifying days;
- The DRA or customer is not taking any deliberate action to provide the demand response, e.g., where a load is experiencing an outage unrelated to DRM;
- The customer is providing demand response by moving demand from one connection point at a site to another connection point at the same site so as to show an artificial demand response on one NMI at the site.

These circumstances provide a reference point for the Australian Energy Regulator (AER) to establish whether the DRA has operated in good faith[26], but it is not proposed for AEMO to specifically monitor compliance with these situations.

Question 5 Restrictions on the provision of demand response

1. **In stakeholders' views, how effective would the proposed DRM design be in preventing the exercise of potential gaming opportunities?**
2. **Are there alternative options to improve upon the current design to manage gaming risks?**

5.2.7 Interactions with demand side participation mechanisms

An end user would be able to sell its demand response to a DRA under the DRM. Alternatively, it can also sell it to its retailer or its Distribution Network Service Providers (DNSPs) outside of the DRM. If the retailer is also a DRA then the retailer would have the option to call a demand response from the end user within the DRM or outside of the DRM.

DNSPs contract demand response within the distribution networks to provide network support services (NSS). Loads that provide network support services could also simultaneously participate in the DRM and their DRAs would be entitled to payments for demand response energy from the NEM.

In addition, subject to some restrictions, the DRA would be able to offer aggregated load simultaneously as ancillary service load into the NEM's ancillary services markets and then as a demand response load in the DRM. However, load offered into the

26 The AEMC published on 17 September 2015 the Bidding in Good Faith second draft determination. This proposed draft rule has been proposed to enhance the arrangements that govern generator's offers in the wholesale spot market.

ancillary services markets will be scheduled by the market rather than self-scheduled by the DRA. (See chapter 6 for additional details).

Question 6 Interactions with demand side participation mechanism

1. **Does the proposed DRM design appropriately capture and address all potential interactions between the DRM and other demand side participations options in the NEM?**

5.2.8 Prudential requirements

Prudential requirements in the NEM are a set of controls that minimise the exposure of market participants generally to payment default by a retailer. These controls consist of an ex-ante assessment of credit limits, and a daily ex-post assessment of financial position. The credit limit process is used to set the collateral requirements for each market participant, in the form of bank guarantees required to be lodged in advance.

DRAs and retailers would have their credit limits assessed according to the existing methodology/procedure, with modifications to the credit limit procedures to include consideration of the demand response in the factors to be considered by AEMO in determining prudential settings.

DRAs' financial positions would be assessed daily using demand response energy. Under normal circumstances, a DRA will be a creditor to the NEM with regard to the demand response energy corresponding to the demand response intervals. Debit may arise when the metered energy exceeds the baseline energy or if the regional reference price is negative during a demand response interval. As a result, DRAs would have their position assessed in line with the credit limit procedures to determine whether they need to provide credit support.

Retailers' financial position would also be assessed daily using customer baseline energy during demand response intervals.

Question 7 Prudential requirement

1. **Are the proposed prudential requirements on DRAs and retailers appropriate?**

5.2.9 Settlement charges

Energy settlement has already been covered in section 5.2.3. However, settlement charges would also apply to recover the procurement of ancillary services, compensation costs and participant fees.

The costs associated with ancillary services are currently recovered from market customers, market generators, and market small generation aggregators. For DRAs the fee calculation, whenever applicable, would be based only on the "demand response energy below the baseline" whereas for retailers that are associated with the demand response site the cost recovery would be based on the "baseline energy". Additional arrangements under the DRM would imply the changes presented in Table 5.1 below:

Table 5.1 Proposed Ancillary Services cost recovery

Service	Currently recovered from	DRA	Retailer associated with a demand response site
NSCAS	Market Customers	N/A	Based on baseline energy
SRAS	Market Customers (50%) and (Market Generators & Market Small Generation Aggregators) (50%)	Based on demand response energy below the baseline only	Based on baseline energy
FCAS Contingency Raise	Market Generators & Market SGAs	Based on demand response energy below the baseline only	N/A
FCAS Contingency Lower	Market Customers	N/A	Retailers pay based on baseline energy
FCAS Regulation Causer Pays	Market Customers and Market Generators distributed according to Causer Pays	N/A	Based on SCADA data
FCAS Regulation Residual	Market Customers	Based on demand response energy below the baseline only	Retailers pay based on baseline energy

The NEM prioritises system and market security over economically efficient dispatch, and a number of mechanisms exist in which AEMO can intervene to manage system security or to prevent market failure. Where an intervention has occurred, the participants impacted are entitled to compensation to cover reasonable costs they incur.

The costs of compensation are recoverable according to allocations defined in the Rules. We have summarised the proposed changes to the compensation cost recovery procedure. These are presented in Table 5.2 below:

Table 5.2 Proposed compensation cost recovery

Type	Current arrangements	DRA	Retailer associated with a demand response site
Energy direction	Recovered from Market Customers	N/A	Retailers pay recovery based on baseline energy.
Other direction	Recovered from Market Customers, Market Generators (based on net generation only), and Market SGAs (based on net generation only).	N/A	Retailers pay recovery based on baseline energy.
Administered price cap (APC)	Recovered from Market Customers	N/A	Retailers pay recovery based on baseline energy.
Reserve Settlements	Recovered from Market Customers	N/A	Retailers pay recovery based on Baseline Energy.
Mandatory Restrictions restriction shortfall amount (RSA) -100,000 to 0	Recovered from Market Customers	N/A	Retailers pay based on baseline energy.
Mandatory restrictions RSA < -100,000	Recovered from Market Customers	N/A	Retailers pay in accordance with determination from independent expert, with supporting data based on baseline energy.
Mandatory Restrictions RSA positive	Paid to Market Customers	N/A	Retailers paid based on baseline energy.

AEMO also charges participant fees to recover its operating costs. The proposed changes to the operating cost recovery arrangements under the DRM are summarised and presented in Table 5.3 below:

Table 5.3 Operating cost recovery

Type	Current arrangements	DRA	Retailer associated to demand response site
AEMO participants fees	Market Customers and Market SGAs pay customer fees at a rate per MWh of energy consumed and generated respectively. Market Generators pay generator fees at a fixed rate per day.	DRAs pay customer fees at a rate per MWh of demand response (whether above or below baseline).	Retailers pay customer fees based on baseline energy.

Question 8 Settlement charge

1. **Do stakeholders have any observations over the proposed changes to the way the costs of ancillary services would be recovered from DRAs and/or retailers?**

2. **Do stakeholders have any observations regarding the proposed changes to the compensation cost recovery from retailers?**

3. **Do stakeholders have any observations regarding the proposed changes to the way the operating costs would be recovered from DRAs and/or retailers?**

5.2.10 Other aspects of the proposed DRM mechanism

This consultation paper covers the key features of the DRM proposed in the rule change request. For technical details relating to the registration process, MSATS setup, metering, B2B processes, preparation of demand response settlement data by MSATS, please refer to the detailed design prepared by AEMO. Comments on these aspects are also welcomed.

The rule change request also covers matters relating to the governance of the DRM such as the process for making procedures and reporting by AEMO. These are critical matters that will need to be considered at a later stage in the rule change process if the AEMC considers that a rule should be made. That being said, if stakeholders have views on these areas, comments are invited.

5.2.11 Implementation issues in relation to the DRM

The Energy Council proposes a voluntary approach whereby retailers will be able to choose whether to enable their customers, through implementing changes to allow for appropriate billing arrangements, to offer demand response in the DRM. They could do this either by becoming a DRA themselves or allowing their customers to work through another DRA. The objective is to minimize the system development costs for retailers who do not offer services to large customers, while retailers with large customers could make a commercial decision on whether to support the DRM for their customers based on an opportunity for securing market share and/or increase revenues.

Under the proposed approach retailers would have to take an all or nothing approach to enabling their customers to participate. They would either be able to accommodate any existing eligible customer's participation in the DRM, or they would not support any participation in the DRM by any of their customers. For example, retailers would not have the discretion to decline an eligible existing customer's participation if their systems enable DRM participation, while allowing another customer to participate.

It is proposed that new billing arrangements would only be affected for those customers who participate in the DRM. The proponent envisages that retailers may not be required to have all billing systems in place for the commencement of the DRM rule change as manual workarounds may be viable option in the early stages of the DRM.

Question 9 Implementation issues in relation to the DRM

1. **The Council proposes a voluntary approach for retailers to enable their customers to participate in the DRM. How effective do stakeholders think this voluntary approach will be in encouraging retailers to enable their customers to opt-in into the DRM?**

2. **What are stakeholders' views on allowing manual billing as a viable short term solution to encourage retailers to enable their customers to opt-in the DRM?**

5.3 Voluntary and staged approach

The Energy Council proposes a voluntary approach whereby retailers will be able to choose whether to enable their customers, through implementing changes to allow for appropriate billing arrangements, to offer demand response in the DRM. They could do this either by becoming a DRA themselves or allowing their customers to work through another DRA. The objective is to minimize the system development costs for retailers who do not offer services to large customers, while retailers with large customers could make a commercial decision on whether to support the DRM for their customers based on an opportunity for securing market share and/or increase revenues.

Under the proposed approach retailers would have to take an all or nothing approach to enabling their customers to participate. They would either be able to accommodate any existing eligible customer's participation in the DRM, or they would not support any participation in the DRM by any of their customers. For example, retailers would not have the discretion to decline an eligible existing customer's participation if their systems enable DRM participation, while allowing another customer to participate.

It is proposed that new billing arrangements would only be affected for those customers who participate in the DRM. The proponent also envisages that retailers may not be required to have all billing systems in place for the commencement of the DRM rule change as manual workarounds may be viable option in the early stages of the DRM.

Question 10 Voluntary and staged approach

1. **The Council proposes a voluntary approach for retailers to enable their customers to participate in the DRM. How effective do stakeholders think this voluntary approach will be in encouraging retailers to enable their customers to opt-in into the DRM?**

2. **What are stakeholders' views on allowing manual billing as a viable short term solution to encourage retailers to enable their customers to opt-in the DRM?**

6 Consultation issues on Ancillary Services Unbundling

In order to fulfil its obligation to operate the power system in a safe, secure and reliable manner, AEMO controls key technical characteristics of the power system through ancillary services. Ancillary services have several categories but the ones that are relevant to this rule change request belong to the Frequency Control Ancillary Services (FCAS) category. FCAS are used to maintain the frequency on the electrical system close to fifty cycles per second.

The current rule change proposal aims to unbundle the provision of frequency control from the sale of energy. Taking into consideration the proposed assessment framework in chapter 4, in section 6.1 we discuss the potential barriers to demand side participation (DSP) in ancillary services markets that have been put forward by the Energy Council. The objective is to consult with stakeholders to understand their views on whether current market arrangements identified by the Energy Council have the potential to restrict DSP in the FCAS markets.

In section 6.2 we present the key features of the Ancillary Services Unbundling (ASU) proposal as set out in AEMO's detailed design document[27] included in the Energy Council's rule change request.

6.1 Potential barriers to demand side participation in ancillary services markets

Facilitating entry via greater DSP in the FCAS markets can improve competition in the supply of these services. This is particularly the case since ancillary services are typically not geographically dependent, and can be equivalently provided by loads located anywhere on the grid and through an aggregation of loads.

While the rule change request did not include any evidence about a lack of competition in the FCAS markets, facilitating entry via greater DSP can potentially minimize the risk of market power being exercised in these markets.

6.1.1 Potential barriers relating to current market rules

The current market rules provide that only market participants that purchase and sell electricity on the wholesale spot market can participate in FCAS markets. While it is possible under the current market rules to aggregate load to provide ancillary services, this can only be done by a registered market customer.

This might discourage DSP in the ancillary services market to avoid the costs of being exposed to the wholesale spot market price or comply with AEMO's dispatch instructions - although participating in market dispatch would be voluntary for these loads. Further, some of these loads might have the ability, either individually or part of

27 AEMO, Appendix B: Demand Response Mechanism and Ancillary Services Unbundling - Detailed Design, AEMO, 15 Novemeber 2015.

an aggregated load, to meet the technical requirements to successfully participate in the FCAS markets. This raises concerns where their participation could result in lower cost and higher quality in the provision of FCAS services to AEMO.

Overall, these arrangements might explain limited DSP in the NEM's FACS markets. For example, with the exception of an aluminium smelter and two pumped hydro loads, all of the 20 registered participants to provide FCAS services in the NEM are generators.

Question 11 Potential barriers to demand side participation in FCAS markets

1. **Do stakeholders agree that current market arrangements where only market participants that purchase or sell electricity on the wholesale spot market can participate in FCAS markets are a barrier to entry that restrict DSP in the FCAS markets?**

2. **Do stakeholders agree that facilitating entry via greater DSP, either as individual or aggregated loads, can result in lower cost and higher quality provision of FCAS services while minimizing the scope to exercising market power in these markets? Do stakeholders have any particular evidence to support their views?**

3. **In which category ancillary service provision do stakeholders believe that entry will be more likely? Are there any foreseeable future changes that might broaden the scope of entry in markets where demand response has generally not been able to provide ancillary services?**

6.2 The proposed unbundling of ancillary services

Beyond unbundling the provision of ancillary services from the purchase of energy in the wholesale spot market, it is not proposed to change the regulation around the provision of ancillary services. Under the proposed rule, a DRA wanting to provide ancillary services to the market would be able to do so, in accordance with the existing ancillary services procedures. The load offered must meet the technical requirements for providing ancillary services.

Similarly to the previous chapter, the Commission invites comments on any aspect of the detailed design detailed presented in the following section or in AEMO's detailed design document. In addition, the following questions on the overall aspects of the proposed design are put forward for consultation with stakeholders:

Question 12 Questions on the overall ancillary services unbundling (ASU) proposal

1. **In stakeholder's view, how would the ASU proposal impact on the cost of balancing supply and demand in the NEM?**

2.	**Would the ASU proposal result in improved ability for AEMO to manage system security and reliability? What aspect of the rule change would contribute to this?**
3.	**Would the ASU proposal result in reduced ability for AEMO to manage system security and reliability? What aspect of the rule change would contribute to this?**

6.2.1 DRAs and ancillary service load accreditation

A new class of market participants, a DRA would be able to offer ancillary services to AEMO from accredited ancillary services loads:

- An ancillary service load will define an individual or aggregated load from which the ancillary service is provided;
- A DRA will be able to seek accreditation for a load as an ancillary service load. This load need not to be a demand response load but only a DRA will be able to seek accreditation of a demand response load as an ancillary service load;
- A DRA will be allowed to aggregate load across sites to form an ancillary service load independently of the retailer - although there are technical and communication requirements that must be satisfied before this can be done. A demand response load included in such aggregation can simultaneously be offered as demand response load; and
- An aggregated ancillary services load must be able to meet the market ancillary services specification (MASS). The MASS may need to change to provide guidance on classifying loads as ancillary services load.

6.2.2 Provision of ancillary services

The Energy Council predicts that for technical reasons a demand response load will generally only be able to offer three contingency type frequency raise services – fast, slow and delayed, though new technologies may allow some loads to satisfy the technical requirements for the other contingency services.

Loads classified to provide market ancillary services will be scheduled through the central dispatch process. Payments for ancillary services would be funded by the broader market.

In line with current rules relating to market customers offering FCAS, a DRA will be responsible for ensuring it does not offer ancillary services that cannot be physically delivered, and must also ensure a load that has been enabled to provide ancillary services is able to provide the service.

Currently, a market customer enabled for a service that it could not provide is still paid for that service but would be in breach of its obligations to follow a dispatch instruction. Similarly, outside the routine revision window, there will be no provision for a mechanism to "claw back" ancillary service payments made to a DRA that was unable to provide the service. Instead, this would be a rule breach and the DRA may incur penalties if this occurred, as is the case with a market customer.

There will be restrictions imposed on how ancillary service load can be sold to the market:

- A DRA cannot include a load as an ancillary service load if the end user has generation measured at its NMI which is sold as generation to the NEM via a market generator or market small generation aggregator. However, if the generation is not sold to the NEM as generation then the DRA can include the load as an ancillary service load;
- Each of its ancillary service loads is at all times able to comply with the latest market ancillary service offer for the relevant trading interval; and
- It will be the responsibility of the DRA to establish compliance of its ancillary services load customers with these requirements.

6.2.3 Interactions with the DRM

As already noted, an ancillary service load will define an individual or aggregated load from which the ancillary service is provided. The DRM design would allow any demand response load included in such aggregation to be simultaneously offered as DRL.

Where a DRA has a load classified as both DRL and as an ancillary service load then it must ensure that it is able to satisfy its ancillary service obligations when providing demand response. It will be the DRA's responsibility to establish compliance of its ancillary services load customers with this requirement.

Question 13 Interactions with the DRM

1. **Does the ASU proposal appropriately capture and address all potential interactions with the proposed DRM?**

7 Lodging a Submission

The Commission invites written submissions on this rule change proposal.[28] Submissions are to be lodged online or by mail by 10 December 2015 in accordance with the following requirements.

Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on Rule change proposals.[29] The Commission publishes all submissions on its website subject to a claim of confidentiality.

All enquiries on this project should be addressed to Arik Mordoh on (02) 8296 7800.

7.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ERC0186. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

7.2 Lodging a submission by mail or fax

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

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

The envelope must be clearly marked with the project reference code: ERC0186.

Alternatively, the submission may be sent by fax to (02) 8296 7899.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter.

If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

28 The Commission published a notice under section 95 of the NEL to commence and assess this rule change request.

29 This guideline is available on the Commission's website.

Abbreviations

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APC	Administered Price Cap
ASU	Ancillary Services Unbundling
BCM	Baseline Consumption Methodology
FCAS	Frequency Control Ancillary Service
FRMP	Financially Responsible Market Participant
DNSP	Distribution Network Service Provider
DRA	Demand Response Aggregator. A new class of market participant proposed in this rule change request
DRL	Demand Response Load
DRM	Demand Response Mechanism proposed in this rule change request
DRN	Demand Response Notification
DSP	Demand Side Participation
EMMS	Electricity Market Management System
ERCOT	Electric Reliability Council of Texas
MASS	Market Ancillary Services Specification
MSATS	Market Settlement and Transfer Solutions
MTR	Multiple Trading Relationships
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective

NMI	National Metering Identifier
NSCAS	Network Support and Control Ancillary Services
PJM	Pennsylvania-New Jersey- Maryland interconnection
RERT	Reliability and Emergency Reserve Trader
RSA	Restriction Shortfall Amount
SRAS	System Restart Ancillary Services
TNI	Transmission Node Identity
TNSP	Transmission Network Service Provider
TSS	Tariff Structure Statement