21 December 2018

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Dear Commissioners,

AEMC 2018, Wholesale Demand Response Mechanisms, Consultation Paper

EnergyAustralia welcomes the opportunity to comment on the Wholesale Demand Response rule change proposals and the AEMC's (the Commission) alternative options.

EnergyAustralia considers demand response to be critical in managing costs across the entire supply chain in a market characterised by increasingly intermittent supply-side generation. Buyers, and sellers, responding to price signals is a foundational principle of efficient markets. We strongly support the development of Demand Response (DR) products and services in the National Electricity Market and believe the current market regulatory arrangements in the NEM support the efficient development of Demand Side Participation (DSP). Given the strong growth and rapid evolution of DR solutions under the existing regulatory frameworks, we encourage the AEMC to undertake a rigorous assessment to ensure the *additional* benefits of potential rule changes will exceed the costs for customers.

EnergyAustralia is one of Australia's largest energy companies with around 2.6 million electricity and gas accounts in NSW, Victoria, Queensland, South Australia, and the Australian Capital Territory. We also own, operate and contract an energy generation portfolio across Australia, including coal, gas, battery storage, demand response, wind and solar assets, with control of over 4,500MW of generation in the National Electricity Market (NEM).

EnergyAustralia has a growing demand response portfolio. We currently have over 50MW contracted as part of the ARENA demand response program, which includes over 9,000 mass market customers and a portfolio of C&I contracts across 40 sites. We also market products, such as the Redback Smart Hybrid System, which allow customers to take control of their energy consumption and undertake independent and orchestrated demand response. We also offer customers time-of-use tariffs which allow them to benefit from optimising their consumption. Furthermore, EnergyAustralia has long offered wholesale pool pass through contracts and demand, or price, responsive services to C&I customers. Recently we have observed strong growth in interest from customers seeking to reduce their exposure to high and volatile wholesale prices.

Current Availability and Benefits of DR
Demand response has potential to increase the efficiency of energy delivery within the NEM. EnergyAustralia supports growth in the provision of competitive demand response products and services that will drive lower costs for all customers. Possible benefits of demand response, which are shared with all customers, include:

- the potential to reduce peak consumption levels, reducing the need to invest in high-cost and low-utilisation network assets and generation capacity,

- a source of on-demand flexible load to balance short term reserve shortfalls or supply-demand imbalances,

- an alternative tool for market participants to manage their exposure to spot prices, allowing customers to benefit from lower retail prices,

- a vehicle to drive greater engagement by customers in managing their energy use and costs.

The Commission previously considered a Demand Response Mechanism(DRM)[1] rule change proposal in 2016. It did not proceed with the DRM as it considered that the benefits associated with the mechanism could be achieved without regulatory reform and that regulatory barriers to entry did not exist. In the two years since this decision was made there has been a notable increase in the number of businesses and business models that provide demand response products and services to customers. As the closure of base load generators has created upward pressure on cyclical wholesale prices, both incumbents and new entrants have invested to offer innovative products and services that create value for customers. This development has included both energy market and network support products and services.

The growth in offers has been supported by developments in energy control and monitoring technologies, increasing wholesale prices and volatility creating greater opportunities to realise value and greater customer awareness and interest in managing usage. The growth has been facilitated under the current rules framework, as anticipated by the Commission in the DRM consultation, and is delivering benefits to customers and the market. New business models, products and services will continue to develop as the market tests different models, technology costs continue to decrease, and retailers compete to create more valuable services to attract customers.

Benefits, costs and risks of proposed DR reforms
The Commission has outlined the additional benefits that are anticipated with the implementation of one, or a combination, of the proposed rule changes; including:

- Efficient consumption by increasing customer opportunities to respond to wholesale prices

- Increased competition for DR

- Greater transparency of the price responsive load

[1] Demand Response Mechanism and Ancillary Services Unbundling, AEMC Rule Change (ERC0186), 2016, https://www.aemc.gov.au/rule-changes/demand-response-mechanism

- Facilitating the use of demand response to provide other services

When considering the rule change proposals, the AEMC should identify whether the reforms will deliver substantial benefits over and above benefits that occur, or could be delivered, within the existing regulatory framework. There is no apparent market or regulatory failure impeding development of efficient DR services in the NEM and there are other ways to provide the anticipated benefits, such as transparency of price responsive load, with less substantial reforms.

The AEMC process should identify whether the reforms would deliver a material increase in the number of DR products and services. In our view, the reforms do not create increased incentives, or price signals, for demand response providers; or create new sources of value for customers that do not already exist. Given the likely costs of implementation, the benefits of competition from additional DR must be demonstrable and significant.

The implementation of some of the options discussed in the paper would incur significant costs upon AEMO and existing market participants, which would ultimately be borne by customers. Any potential benefits must exceed these costs for any of the proposals to be considered in the best interests of all customers. Rule changes, particularly those that impose significant costs on consumers, should not be justified by supporting particular DR business models that one or more suppliers prefer, while disadvantaging or crowding out other suppliers. There is a risk that some of the proposed options may actually reduce competition by creating new barriers and distortions, or create quasi-regulated offers that stifle competition. This creates no additional value for customers.

Finally, any market reform that introduces the vagaries of counterfactual baselines into settlement processes, to quantify the amount of DR provided, should be approached with a high degree of caution, particularly when applying to mass market customers. The current settlement arrangements for billing based on actual consumption are fundamental to the NEM and customer support for bills based on estimated, or calculated, reads is low. Every baseline method is subject to error; a baseline is often considered acceptable if the random error is 'only' plus or minus 20%. The risks of errors and information asymmetry can be appropriately managed, shared and allocated in a private contract between a customer and retailer. In the current arrangements these costs and risks fall to the participants best placed to manage them. However, the introduction of an estimated baseline into market settlements exposes all other customers to the risk of additional costs arising from systemic errors, bias and information asymmetry. Risks that they cannot manage.

The remainder of this submission provides a response to some of the questions raised in the Consultation Paper, outlines some additional issues to be addressed, and offers possible solutions and preferred approaches for further consideration by the Commission.

If you would like to discuss this submission, please contact Georgina Snelling on 03 9976 8482 or Georgina.Snelling@energyaustralia.com.au.

Regards

Sarah Ogilvie
Industry Regulation Leader

Attachment A – Demand Response in the NEM

There has been strong growth in the provision of DR related products and services in recent years. The Consultation paper cites a lack of retailers offering DR despite growing customer interest as a key reason to introduce a DR rule change. We disagree with this characterisation of the market. This section stresses the underlying price signal-based, and therefore cyclical, nature of DR, and highlights customer's current ability to access DR, the current level of DR capacity in the NEM, the variety of products and services that are available to consumers and evidence of DR utilisation.

Defining Demand Response

Demand response activities are broad and include behavioural and device-controlled responses, load shifting and absolute demand reduction, the use of storage assets or embedded generation, and automated price response optimisation.

It is important that any framework for demand response considers the types of demand response that are available, or could be offered, to ensure that the design does not create barriers to entry for particular types of activities. For example, is it reasonable, or even feasible, for disaggregated behavioural demand response to be scheduled? Are load shifting customers discouraged as they are charged twice for the same consumption under a DRM? There is a risk that by implementing a regulatory change that facilitates entry of a particular type of demand response service, others face higher barriers to entry. The Commission should therefore be clear about what it means by demand response and how the proposed changes would affect the different types of response activity.

Consumer access to demand response services

With on-going installation of smart meters, the number of customers with the ability to access demand response services is increasing. Smart meters are usually required for DR as they allow service providers remote access to consumption data measured at half-hourly intervals. Smart meter penetration in the NEM is currently over 37%[2], with 81,000 meters installed since introduction of the *Competition in Metering* rule change in December 2017. This is in addition to the existing 2.8 million meters installed during the regulated Victorian roll-out. Smart meter penetration will continue to increase with the ongoing replacement of expired meters and the proactive installation of meters by retailers, greatly increasing the number of customers with the ability to access to demand response services.

DR products and services available in the NEM

Demand management is not a new concept. Retailers have long offered demand response services or wholesale pool price pass through contracts to C&I customers. For mass market customers, controlled loads, such as water heating, have been in place for many years and while most are static, Ergon operate dynamic ripple control hot water which allows it to shift the heating load to times of low network utilisation.[3,4] Mass

[2] Global Settlements and Market Reconciliation, Final Rule Determination (ERC0240), AEMC 2018, p13, https://www.aemc.gov.au/sites/default/files/2018-12/Global%20Settlement%20and%20Market%20Reconciliation%20-%20For%20publication.pdf

[3] https://www.ergon.com.au/retail/residential/tariffs-and-prices/economy-tariffs

[4] Network Optimisation Metering Management Plan, https://www.aer.gov.au/system/files/Ergon%20Energy%20-%2005.04.03%20Mmt%20Plan%20Metering%20-%20October%202014.pdf p13.

market demand response has also been achieved with time-of-use (TOU) tariffs that provide static signals to consumers about when it is cheapest to consume energy.

More recently, network tariff reform and technology developments have allowed retailers to engage smaller customers in more active price responsive behaviours. There is now a variety of demand, and price, response products and services available to customers in the NEM including products to assist customers with behavioural, automated and controlled responses to price. These products and services are offered by incumbent retailers, new entrant retailers, and non-retailer 3rd parties (either in partnership with retailers or acting behind the meter).

There are also numerous programs providing funding and support for the development and testing of demand response products including the ARENA Demand Response program, Origin Energy's[5] and EnergyAustralia's[6] sponsorship of separate start-up support programs which have included DR initiatives, and the regulated Demand Management Incentive Scheme. The level of investment indicates commitment to the demand response sector and suggests that demand response offerings will continue to emerge, evolve and improve.

Sample of Demand Response products and services available to customers[7]

Retailers				
Mass Market				**C&I**
VPPs	**Energy DR offers**	**TOU Tariffs**	**Wholesale pool pass through offers**	
EnergyAustralia	EnergyAustralia	EnergyAustralia	Amber energy	EnergyAustralia
Ergon Energy[8]	Powershop	AGL	FlowPower	ERM
Simply Energy (S.M.A.R.T)[9]	AGL	Origin	UrthEnergy (suspended)	FlowPower
AGL	Pooled Energy[10]	Alinta Energy		Origin
CONSORT Bruny Island Battery Trail[11]	Diamond Energy[12]	Simply Energy		AGL
	FlowPower	Momentum		
	ERM (C&I)	Powershop		

Non-retailers	
Demand management products, platforms & services	**Distribution networks**
GreenSync	Ausgrid *GoodGridders*
Redback	Ausnet trial[13]
BillCap[14]	United Energy[15]
Reposit Power[16]	Jemena trial
SolarEdge Grid Services[17]	Ergon Energy

[5] https://www.originenergy.com.au/about/investors-media/media-centre/doubling-the-commitment-for-a-cleaner-energy-future-14-start-ups-take-on-australias-cleantech-sector.html
[6] https://www.startupbootcamp.org/accelerator/energy-australia/
[7] Some offers are trials only
[8] https://arena.gov.au/news/testing-a-model-for-residential-solar-and-battery-storage/
[9] https://www.simplyenergy.com.au/energy-solutions/battery-storage/
[10] https://www.pooledenergy.com/energy-management/
[11] http://brunybatterytrial.org/
[12] https://diamondenergy.com.au/gridcredits100/
[13] https://www.ausnetservices.com.au/Residential/Electricity/Demand-Management
[14] https://billcap.com/about/
[15] https://arena.gov.au/projects/peak-demand-reduction-using-solar-storage/
[16] https://repositpower.com/how-it-works/
[17] https://www.solaredge.com/aus/solutions/grid-services

Sunverge[18]	
SwitcheDin[19]	
Sensibo (manages AC)[20]	
Enel X (previously EnerNOC)	
Yurika[21]	

Demand response capacity – Demand Side Participation Guidelines

Data available from AEMO's Demand Side Participation (DSP) portal suggests that there is up to 207MW of price responsive load, and 278MW of reliability response load in the NEM, representing around 0.4% of total installed capacity in the NEM.[22]

As described by AEMO, the DSP data

> *"captures direct response by industrial users, and consumer response through programs run by retailers, DSP aggregators, or network providers... [The published data] reflects the observed 50% probability of exceedance DSP resource response to different wholesale prices in recent years. Reliability response DSP estimates are also included, referring to situations where additional DSP is observed in response to a Lack of Reserve Notice… The capacities listed exclude any DSP procured through the Reliability and Emergency Reserve Trader (RERT) process."*

Using the DSP data and 2017-18 maximum demand forecasts provided by AEMO, it is possible to calculate the proportion of currently available demand response in each region. The volume of DR expected to be available for a non-RERT reliability response represents between 0.2% and 1.7% of the 50% POE Maximum Demand forecast.

Estimated Demand Side Participation by trigger, Summer 2017-18[23,24] (MW)

	NSW	VIC	QLD	SA	TAS	Total
Trigger Price >$300/MWh (MW)	78	28	32	1	6	145
Trigger Price >$7,500/MWh (MW)	105	34	40	6	22	207
Reliability response (MW)[25]	105	77	66	6	23	278
Maximum Demand 2017-2018 (50%POE forecast) (MW)	12,663	8,802	8,625	2,848	1,337	
Maximum Demand 2017-2018 (10%POE forecast) (MW)	14,317	9,564	9,173	3,127	1,364	
Reliability response as proportion of 50% POE max demand	**0.8%**	**0.9%**	**0.8%**	**0.2%**	**1.7%**	

In the consultation paper, the AEMC have indicated that only around half of participants have complied with the rules to provide information to AEMO[26]. We suggest that the AEMC seek further information from AEMO as to the nature of non-compliant businesses and whether these parties are expected to support significant volumes of DSP. In other

[18] http://www.sunverge.com/energy-management/
[19] https://www.switchdin.com/electricity-companies
[20] https://sensibo.com/pages/learn-more
[21] https://www.yurika.com.au/
[22] Based on installed capacity of 55,590 MW (including rooftop solar PV), AER, State of the Energy Market 2018, p75, https://www.aer.gov.au/publications/state-of-the-energy-market-reports/state-of-the-energy-market-2018
[23] 2018 Electricity Statement of Opportunity (ESOO) http://forecasting.aemo.com.au/Electricity/MaximumDemand/Operational , [accessed 20 December 2018]
[24] AEMO Demand Side Participation 2017-18, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Electricity-Forecasting-Insights/2018-Electricity-Forecasting-Insights/Demand-Side-Participation [accessed 20 December 2018]
[25] Refers to situations where a Lack of Reserve notice (LOR2 or LOR3) is issued.
[26] Wholesale Demand Response Mechanism, Consultation Paper, AEMC 2018, p32

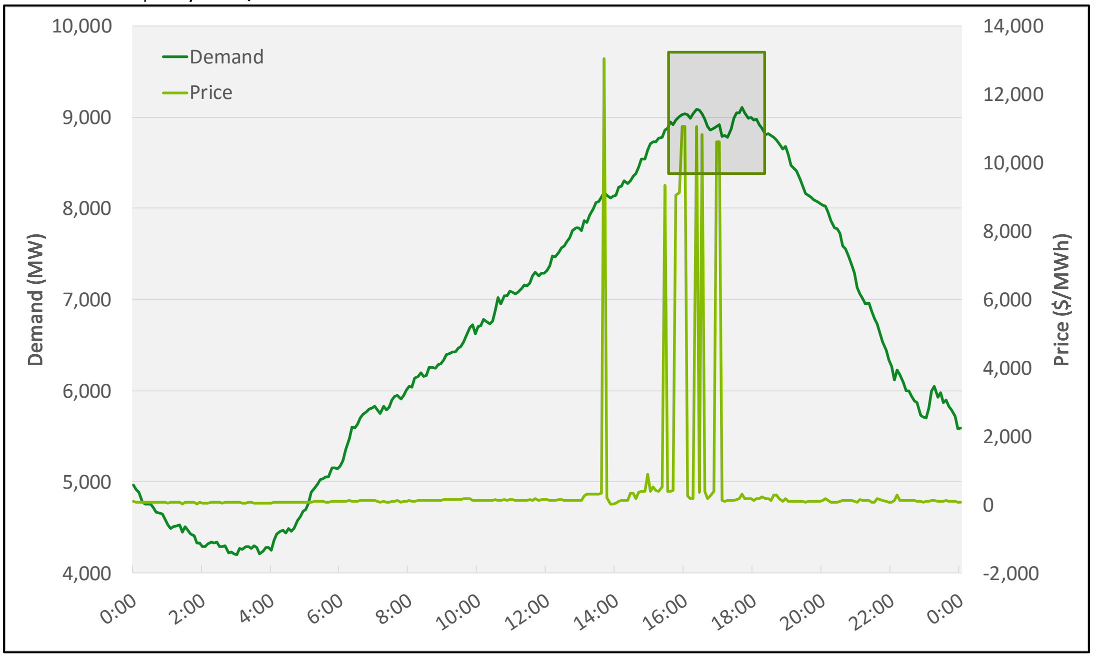
words, while AEMO have received 50% of expected submissions, does this reflect 50% of anticipated MW.

Further, in addition to the estimated DSP levels, it would be useful if AEMO were able to report the total aggregate capacity available broken down by type of price responsive load. For example, volume of load that has a passive price response (NMIs on TOU tariffs) and active price response (price or direction triggered, controlled or behavioural). This would provide greater transparency to the market about levels of demand response availability.

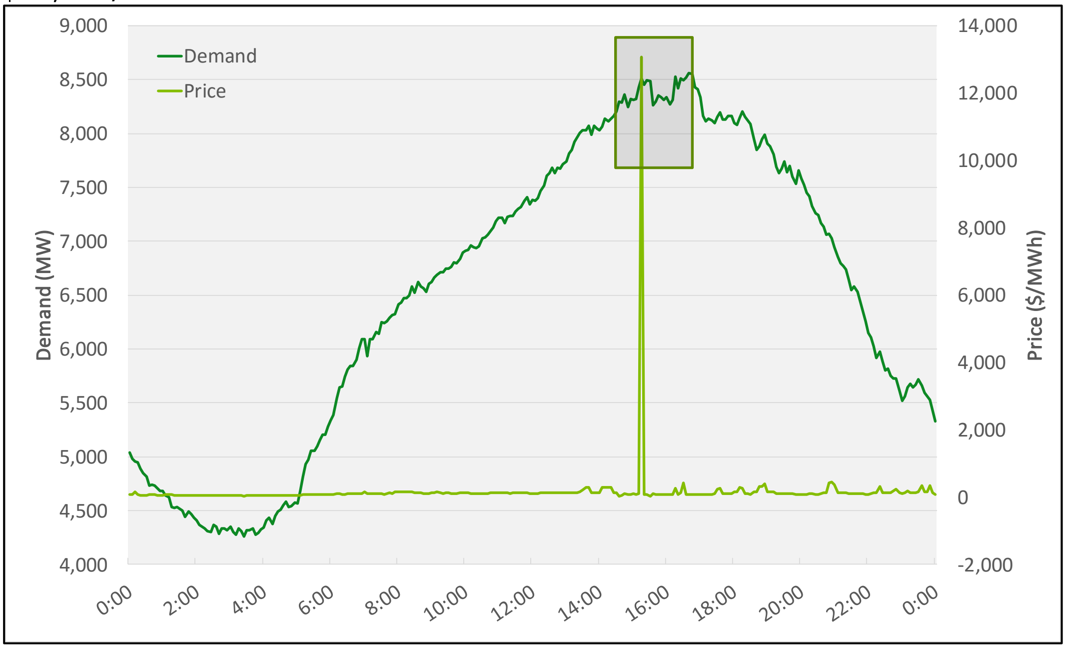
Evidence of Demand Response utilisation

Observation of market data suggests that demand response is activated on days where prices exceed $10,000/MWh. Some examples are provided below:

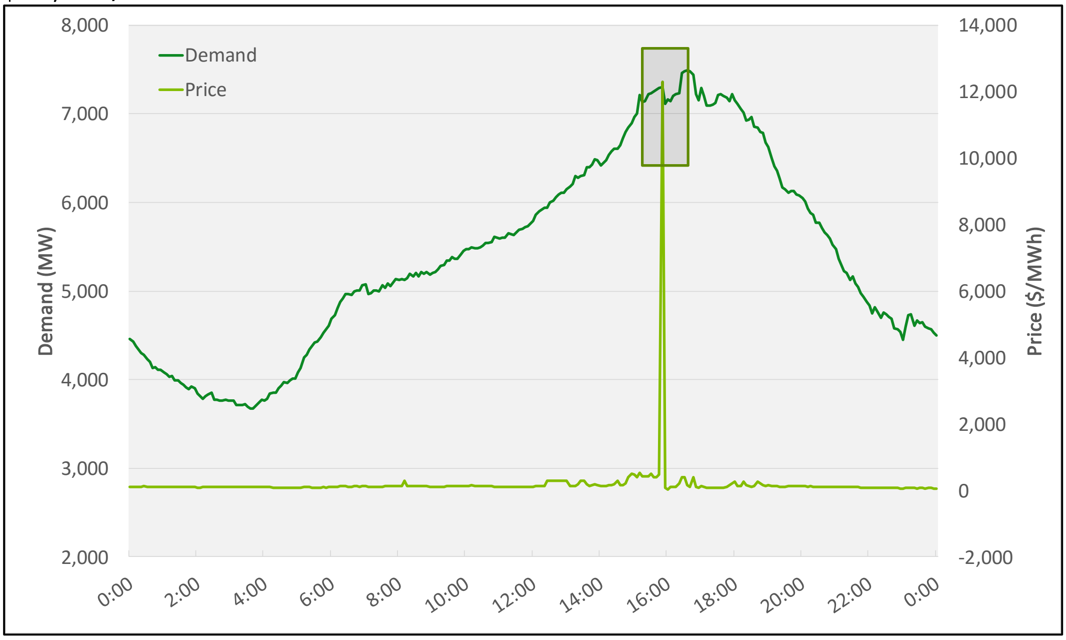
- **Wednesday 7 February 2018, Victoria, maximum temperature of 37.4°C**
  Load reduction of approximately 250MW coincides with a period where prices exceeded $10,000/MWh.



- **Friday 7 December 2018, Victoria, maximum temperature of 38°C**
  Load reduction of approximately 250MW following period where price exceeded $10,000/MWh.



- **Wednesday 12 December 2018, Victoria, maximum temperature of 33.6°C**
  Load reduction of approximately 160MW following period where price exceeded $10,000/MWh.



The observed decrease in consumption could be due to many factors but physical market traders regularly anticipate that demand will reduce on extreme weather days with high prices, suggesting that demand response is being activated in the market.

Using public data only it is difficult to identify the participant(s) or customer(s) that have curtailed by observing market data. EnergyAustralia will provide more information on its demand response activities to the Commission in a confidential submission. A public example of demand response being utilised by a major customer is SA Water which the AEMC identified in 2016 as having a wholesale pool price pass through contract which encouraged it to curtail load during periods of high prices.[27]

Evidence of competition for demand response services

The contracting of DR under the RERT mechanism in the past 2 years provides some evidence that there is competition for DR services as customers are actively shopping around for the highest value offers. However, as we have commented previously[28], RERT has created competition for traditional demand response, incentivising DR to exit the wholesale market. We remain concerned about these developments in the market and would encourage the AEMC to consider the distortionary signals this is creating and its impact on further in-market demand response being developed.

Potential size of residential mass market demand response

When considering the value that a demand response framework could deliver to customers, it is useful to assess the natural limit of demand response capability. This can be compared to existing and anticipated demand response to assess whether the changes proposed would significantly increase the natural cap, or ability to reach this cap. We recommend the AEMC ascertain the potential size of demand response capacity within the small customer market using an estimated penetration rate (that recognises that not all customers will see value in participating) and a firmness factor for responding to a signal.

A Marchment Hill study focused on residential DR suggested there may be potential capacity of 1,100MW of DR under a medium-level uptake scenario.[29]

Available residential load under management (GW) – Scenario-based, NEM-wide

Device(s) / Appliance(s) Controlled	**Available load under management (GW)**		
	Low take-up (5%)	*Med take-up (15%)*	*High take-up (30%)*
Air Conditioning	0.09 GW	0.27 GW	0.53 GW
Water Heating	0.12 GW	0.36 GW	0.71 GW
Pool Pumps	0.02 GW	0.06 GW	0.12 GW
Dishwasher	0.05 GW	0.16 GW	0.32 GW
Washing Machine	0.04 GW	0.11 GW	0.21 GW
Tumble Dryer	0.05 GW	0.16 GW	0.32 GW
TOTAL:	**0.37 GW**	**1.1 GW**	**2.2 GW**
% peak reduction:	**1.1%**	**3.2%**	**6.4%**

[27] Demand Response Mechanism and Ancillary Services Unbundling, AEMC Rule Change (ERC0186), 2016, p57, https://www.aemc.gov.au/rule-changes/demand-response-mechanism

[28] EnergyAustralia submission to Enhancement to the Reliability and Reserve Trader rule change consultation, https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

[29] http://www.marchmenthill.com/qsi-online/2017-08-17/residential-sector-demand-response-worth-chasing/

Attachment B – Comments on specific rule change proposals

Demand Response Mechanism (ERC0247)

The DRM proposed by PIAC, TEC and the Australia Institute is similar to the proposal considered by the AEMC in 2016, with an extension to now include mass market customers. Under this proposal, demand response offers into the spot market by a new participant category, Demand Response Aggregators (DRAs), would be scheduled by AEMO. AEMO would make changes to wholesale energy settlement arrangements so that retailers were financially responsible for baseline levels of consumption at the prevailing spot price, DRAs would receive compensation for the volume difference between baseline and actual consumption at the spot price. There would be no change to generator compensation, they would continue to be dispatched to the 'actual' scheduled demand.

Retailers are best placed to deliver the benefits of demand response to customers, either independently or in conjunction with demand response specialists, by optimally utilising DR within their portfolios to reduce the costs of supplying electricity. A DRA is likely to create inefficiencies and costs within the market that will be borne by customers. A clear case needs to be established to justify how significant additional value, for all customers, will be created by creating a new participant category and introducing a DRM. In our view, a DRM is only suitable for a small number of sophisticated customers. Mass market customers should not be settled using baseline consumption calculations as this creates uncertainty and additional costs for consumers.

A formalised DR market addresses a design failure within capacity markets. There is no equivalent failure within energy only markets as the spot price contains all the information needed to inform efficient consumption, dispatch and investment. The market rewards reduced consumption with avoided costs of using the service at the time.

Challenges to creating value with a DRM

As articulated by the Commission in the consultation paper, this option establishes a transfer, not a creation, of value from retailers to a new type of market participant. It does not directly create new value for participating customers or the broader market. The fundamental transaction under the proposed DRM is for a customer to pay one entity (a retailer) to purchase electricity they do not use, while simultaneously paying another entity (DRA) to sell that volume of electricity back to the market at exactly the same price and time. The customer therefore pays two margins on a zero-sum transaction, reducing the potential value of DR to the customer.

In contrast, retailers are well placed to generate value for customers by utilising DR within their portfolio. By having visibility of activity within their load, retailers can reduce the overall average price of procuring their load, leading to reduced costs for customers.

The proposed DRM is likely to generate inefficient procurement of capacity, leading to increased costs for customers. First, retailers will not be able to reduce the volume of energy procured to ensure they have covered/hedged their load. As retailers are exposed to the estimated baseline consumption and have no control or visibility of how or when the DR will be activated by the DRA, they will continue to need to cover the baseline (higher) volumes of consumption. As these costs are fixed and sunk well before the time that DR is activated, these costs will need to be recovered from customers, despite the actual reduction in load. This will increase the hedging costs for all retailers as they will continue to contract to cover forecast baseline consumption, regardless of whether DRAs activate the response or not.

Second, retailers will face uncertainty and challenges in understanding the volume of energy to procure. The retailer will not know in advance when DR will be exercised by their customers, creating uncertainty at any given point as to whether they should be calculating forecast load using existing methodologies, or baseline methodologies. Retailers will in essence be attempting to forecast a baseline forecast.

For customers that shift load, there are likely to be minimal benefits from this mechanism. However, this is exactly the type of behaviour that a demand response rule change should facilitate. Load-shifting customers will pay for their consumption, as per the baseline, and receive some compensation from their DRA. They will then also pay for the consumption of the shifted load. If the compensation from the DRA does not cover the cost of both charges from the retailer, the customer will be worse off.

Unresolved issues with the use of baselines and existing methodologies

We have strong reservations about introducing a regulatory change that relies on existing baseline calculation methodologies. These are designed around relatively flat and predictable C&I loads. Predicting the counter factual level of consumption for more variable loads is more difficult, particularly with the significant penetration of embedded generation in Australia.

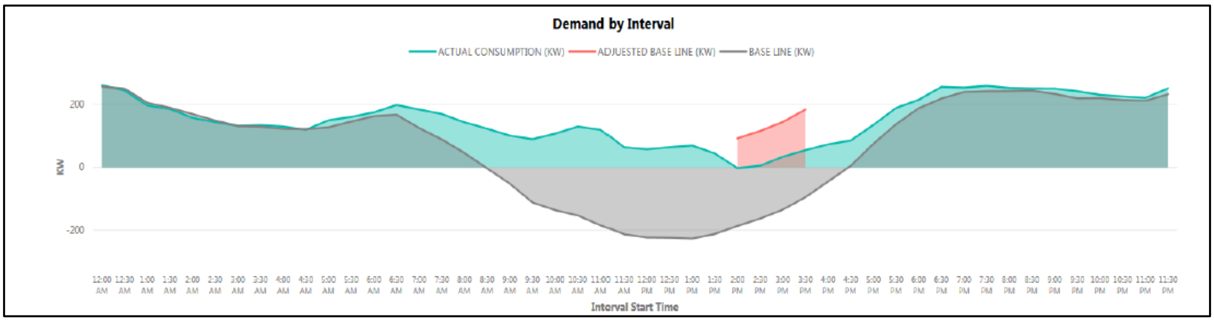
During our ARENA DR program trials, we have identified a number of problems with using baselines with mass market customers, including:

- *The impact of embedded generation on calculating the adjusted baseline.* Using the CAISO methodology, the baseline consumption for a particular day is adjusted to take into account the level of consumption prior the DR event. This adjustment can be materially affect the calculation of the demand response volume. For example, if it is cloudy in the morning, solar panels may export less indicating higher levels of consumption from the connection point. If the clouds move at the time of the demand response event, consumption from the grid will naturally decrease as more solar is utilised, leading to an apparent demand response behaviour. This issue is particularly relevant in Australia due to the large penetration of embedded solar.

- *Customers load shifting to provide a demand response.* Similar to above, the adjusted baseline could be inflated by the inclusion of increased consumption earlier in the day that occurred when a customer anticipated a demand response request for later that day. This could exaggerate the size of the subsequent decrease in load as measured from the baseline.

- *Changes in customer consumption*. In a recent ARENA trial, we observed an artificial inflation of the adjusted baseline as customers appeared to be working from home during extreme weather conditions in Sydney. The majority of the demand response was provided by solar customers as the weather cleared and solar exports increased, resulting in potentially inflated levels of demand response.

Demand response trial results, NSW 28 November 2018



- *Operational changes such as unplanned outages.* This could have similar, but opposite effect to the above. If a customer had reduced their load during the start of the day for operational reasons, and then elected to continue reduced levels of consumption to provide a demand response, this may not be captured as the baseline may have been adjusted down, therefore the actual demand response may not be fully captured.

- *Industry specific consumption patterns*. Using the previous 10 days to estimate the baseline is not appropriate for high street retail where consumption is typically higher on Thursday and Friday due to extended trading hours.

- *Settlement revisions*. These can occur up to 6 months after the date of consumption which can create subsequent revisions of information that has been provided to customers in relation to their performance.

We do not support a rule being introduced before these, and other issues, are resolved, and there is broad testing and industry acceptance of a standard methodology. If a rule was implemented before a methodology had been developed, there is a risk that AEMO would have to develop one within the rule implementation time frame which would reduce the rigour of the process and put the success of the reforms at risk.

We are aware that AEMO have employed Oakley Greenwood to investigate a range of alternative baseline methodologies that could be applied to different customer types and market segments. While this could improve the measurement of DR, it introduces complicated threshold definition issues and increased complexity for consumers, retailers and aggregators in determining the best-fit methodology to use.

The AEMC have suggested that minor inaccuracies are not a concern, provided they are not consistently biased towards a particular participant. However, the above inaccuracies will create unmanageable risks for retailers and could precipitate disengagement by customers who distrust the accuracy of the calculations.

Customer bills based on estimates are highly unpopular and drive complaints volumes. Under the proposed mechanism, retailers would be required to bill their customers based on a combination of metered and estimated reads which we anticipate would increase customer confusion and complaint levels. As the retailer does not manage the DR activity for the customer, it will be complex and costly for retailers and customers to resolve any issues.

Clarification is also needed on whether other consumption-based customer charges are calculated using baseline or actual levels of consumption. This includes network charges, RERT cost recovery, causer pays charges and FCAS cost recovery. There may subsequently be requirements for DRAs to hold Prudentials.

Obligations for market participants

The Consultation paper does not provide details on obligations that would apply to DRAs participating as scheduled resources. As they will have direct access to the wholesale market, the Commission needs to consider how the associated obligations, such as rebidding and late bidding requirement, non-conformance, following targets, ramp rates, power system security requirements would apply to DRAs if they are scheduled.

Demand Response Market (ERC0250)

The South Australian Government has proposed created a separate market for Demand Response a transitionary step to progressing to a full DRM as proposed by PIAC. This market would be co-optimised with existing electricity markets operated by AEMO. The Government posits that this option is less complicated than the DRM so could facilitate an earlier introduction of a DR rule change.

We believe this proposal would still present complications for the market as AEMO would need to consult on and develop the infrastructure to develop the new market. The new capacity gas market has taken AEMO at least 12 months to develop and the secondary Settlement Residue Auction (SRA) infrastructure is expected to take 10 months to develop. Both of these are materially less complex as they are stand-alone markets with simple user interfaces and do not require co-optimisation with the electricity optimisation and dispatch engine, as the proposed DR market would. We support the intent of this proposal but question whether it is a cost-effective proposal with material benefits to be gained.

This market development would be funded by all customers, via retailer participant fees, when arguably it is the DR customers who receive the most immediate benefit. This represents an inefficient cross subsidy between consumers.

We suggest that in the short term, current market rules are delivering DR, volumes are expected to grow and it would be better to use the time to observe the impacts, and increase the transparency, of this DR to inform the design of a sustainable long-term solution.

Combining the DRM and separate market proposals may be preferable

A potential solution to some of the above concerns would be to combine elements of the DRM and NEM market rule change proposals to create a DRM where 3rd parties can register as DRAs, without requiring any agreement with retailers, but instead of retailers being liable for a customer's baseline consumption, they would continue to bill customers based on their actual reads. The cost recovery for the DRA's demand reduction volumes could then be sourced collectively from all market participants, similar to the NEM market proposal.

This approach would address concerns with billing customers based on estimated numbers. Baselining methodologies appear to be more accurate when applied to aggregated loads as this allows individual volatility and errors to be smoothed. As such, the application of the existing methodologies for assessing the aggregate performance of many disaggregated customers would be less problematic. Under this arrangement, DRA's would bear the risk for baseline methodologies, rather than retailers who have no control over the outcomes.

However, this proposal does not address our concerns about how retailers determine the appropriate level of generation to contract and other adverse implications would need to be identified and considered.

Negotiating in good faith and Standing offers (ERC2048)

The AEMC have extended the AEC proposal for obligations on retailers to negotiate DR contracts with 3rd parties by suggesting that retailers could be mandated to offer customers a standing wholesale DR offer or a wholesale pool price pass through contract.

Standing Wholesale DR offer

Developing standardised contracts is difficult in the developing DR market. C&I contracts are typically bespoke to ensure both parties can extract value and the contracting process requires extended collaborative consultation to establish. Mandating an offer is unlikely to result in increased availability of contracts that are in the interests of all customers.

Standing wholesale pass through

Wholesale prices are already available for C&I customers.

By creating a standing offer for mass market customers, there is a risk that customers may not fully understand the ramification of these contracts. It is likely that retailers would need Prudentials from the customers and that additional consumer protections would be required.

The Commission also needs to consider how this offer would operate when the proposed Retailer Reliability Obligation was binding[30]. As currently drafted, retailers will not be able to provide spot pass through contracts to customers as they will need to be contracted to cover all their expected load liability.

Load Shedding Compensation proposal (AEMC proposal)

The AEMC have outlined a mechanism where customers are compensated by their retailer if they are involuntarily shed. Retailers would be exposed to a calculated volume

[30] COAG Energy Council, Firmness Principles for Qualifying Contracts Consultation Paper, December 2018, http://www.coagenergycouncil.gov.au/publications/consultation-retailer-reliability-obligation-detailed-design-issues

of lost load at the market price. The rationale for this proposal is that the market cap limits retailer spot price exposure which limits incentives to invest in capacity.

EnergyAustralia haven't considered this mechanism in detail but provide the below comments on its feasibility.

The price cap within the existing Reliability Standard framework is designed to provide incentives to ensure there is sufficient supply to meet demand. In the recent review of the standard[31], stakeholders were of the view that the current standard is fit for purpose and no evidence has been provided that it should change. As shown in the figure below, reliability-related interruptions account for a very small percentage of total supply interruptions. It is unclear that this mechanism would create additional value. In the recent Enhanced RERT options paper, stakeholders also voiced their unequivocal support for the current form and level of the Reliability Standard.[32]

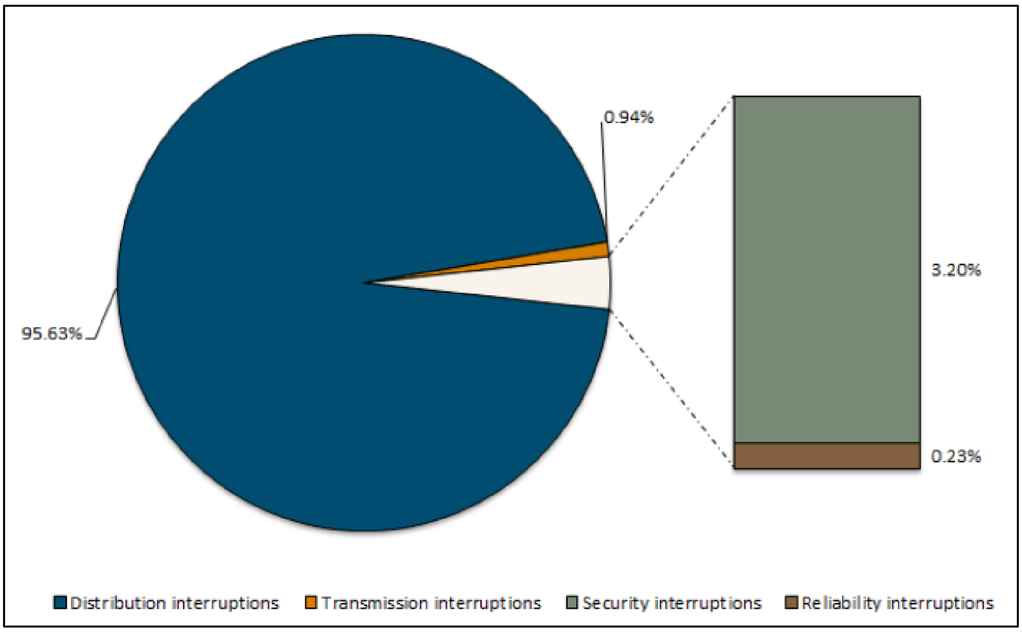
The AEMC has suggested that this approach would improve risk allocation by shifting risk from customers to retailers. However, retailers are not always in control of their DR portfolio so would be unable to manage the allocation of the risk. For example, if a customer decided not to activate when requested, for operational or safety reasons, a retailer is liable to pay compensation for shedding even though it had a contract in place for demand response. It is our strong view that no retailer would ever consider purchasing fewer hedging contracts in the hope that their exposure to the pool price would be less in a time of load shedding.

The Commission would need to carefully consider how reliability-related load shedding was defined. For example, if bushfires created credible contingencies and there was subsequent load shedding, would retailers be liable for compensation payments?

This approach would also require the use of baselines which would be subject to the issues outlined previously.

[31] https://www.aemc.gov.au/markets-reviews-advice/reliability-standard-and-settings-review-2018
[32] https://www.aemc.gov.au/rule-changes/enhancement-reliability-and-emergency-reserve-trader

Sources of supply interruptions in the NEM: 2007-08 to 2016-17[33]



This mechanism may be feasible if it is considered voluntary whereby customers elect a price at which they would be willing to be shed and cost recovery is socialised. However, this would also require the use of baseline calculations and there are complexities in how AEMO would physically be able to shed loads when operating the system.

[33] AEMC Reliability Frameworks Review, Directions Paper, 17 April 2018, https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

Response to selected questions in the consultation paper

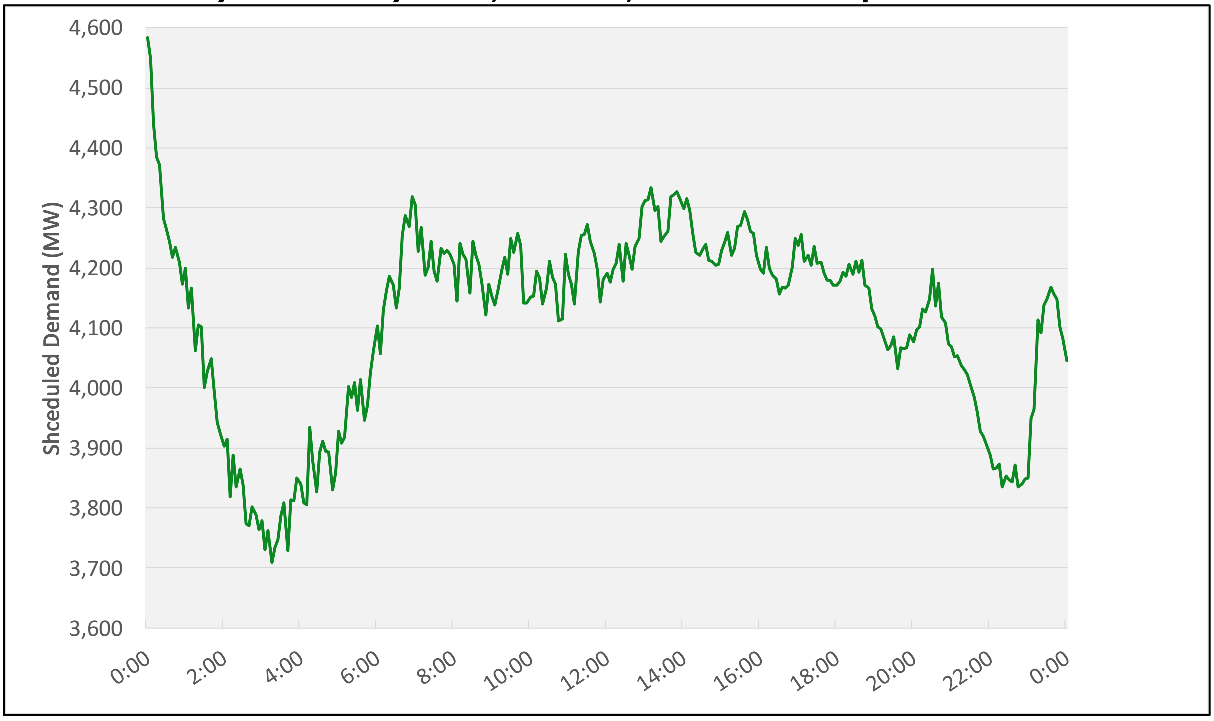
Questions 4 & 7: Transparency and Scheduling

In the consultation paper, the Commission has stated the need for increased transparency of demand side response to improve efficiency in market operations and participant decision making. Scheduling has been proposed as a possible solution to increase transparency for all market participants. We consider there are less costly alternatives to capturing and providing this information to the market. The intent of the DR rule change proposals is to reduce barriers to entry; however, scheduling requirements could have the opposite effect due to the additional obligations this places on participants.

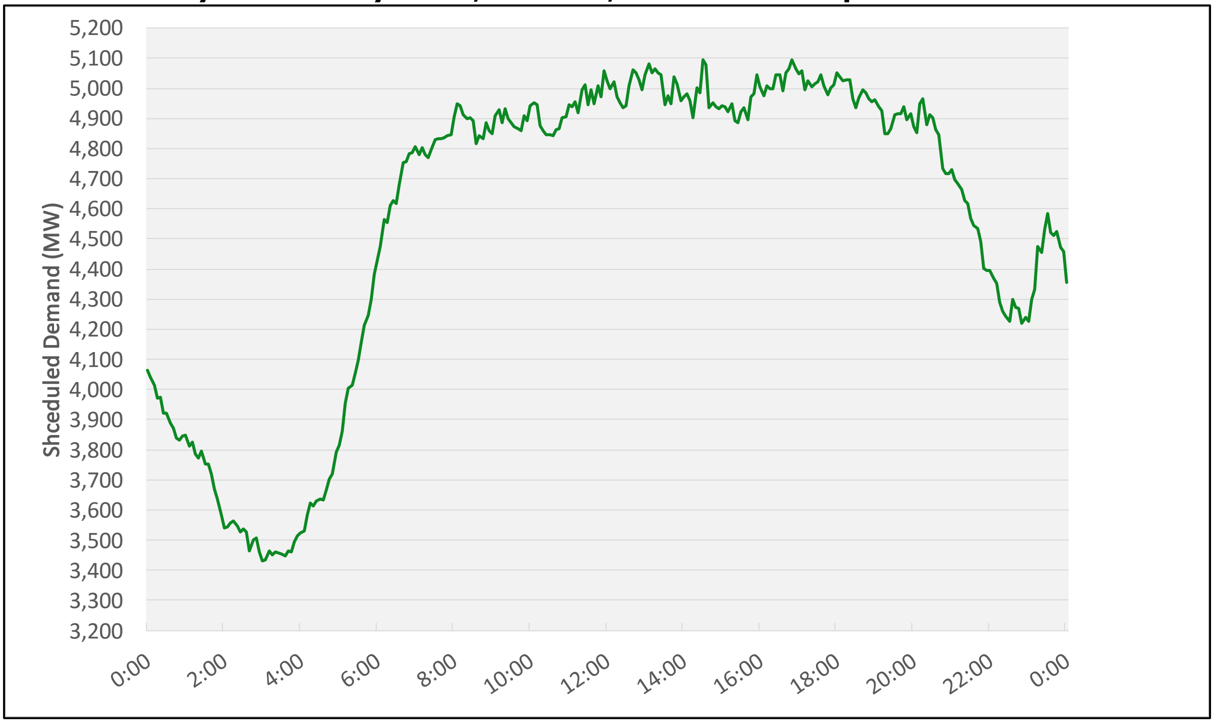
Since its inception AEMO has always been required to manage the unpredictable nature of load when forecasting demand and managing system security. Before developing a complex scheduling system to accommodate demand response, AEMO and the AEMC should assess whether scheduling is actually required to manage the integration of increasing volumes of demand response.

Demand is naturally volatile and fluctuates throughout the day as mass market consumers adjust their consumption, industrial machinery is switched on and off, and weather affects the volume of energy provided by embedded solar generation. The charts below show demand traces on two unremarkable days where there are visible changes in demand in excess of 100MW.

- **Saturday 13 January 2018, Victoria, maximum temperature of 20.9°C**



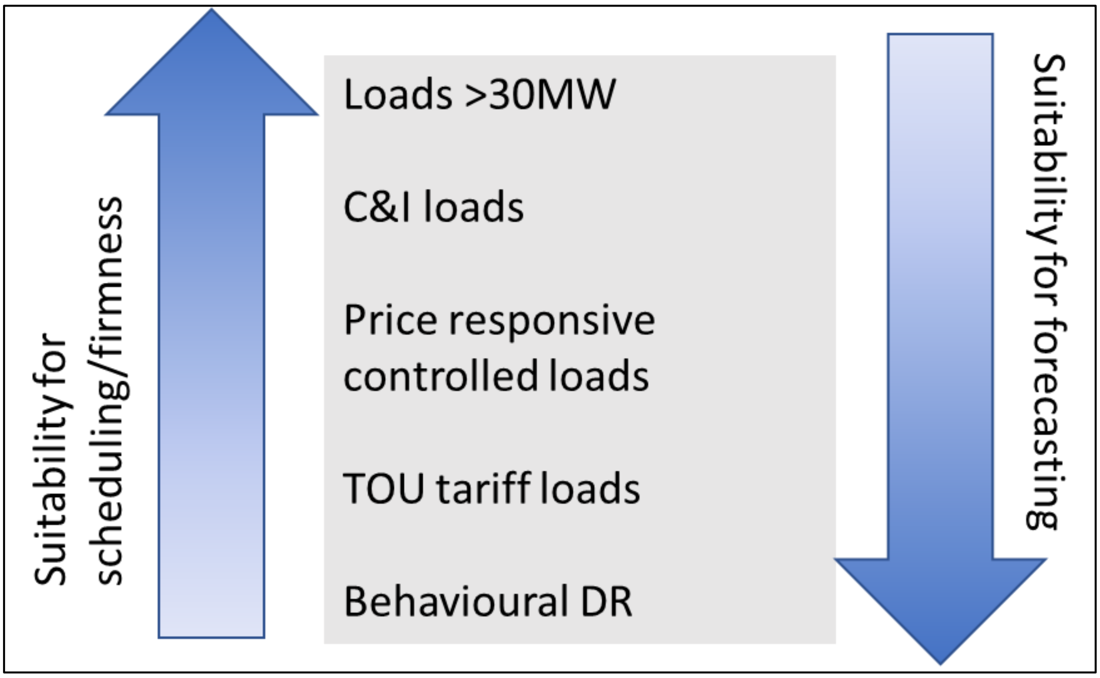
- **Monday 15 January 2018, Victoria, maximum temperature of 20.9°C**



We would anticipate that current volumes of demand response activation would not be significantly larger than this and that the volatility caused by demand response could be managed by existing ancillary services, and limits on ramp rates, in the short term. As demand response grows in scale, AEMO could track the size and impact of co-ordinated changes in demand to assess whether there was a need to schedule particular types of demand response. This could be done by utilising the Demand Side Participation (DSP) data to identify and track the behaviour of particular loads. By observing the swings in demand caused by individual, or co-ordinated aggregated loads, AEMO could assess the impact that these have on the system and whether they pose a material threat to system security and reliability. The NEM is already operated to withstand the loss of the largest generator, or network element, which is far more than anticipated levels of demand response.

A key challenge that AEMO faces in scheduling demand response is assessing and managing the varying degrees of firmness that different types of demand response offer. Large C&I loads are less predictable as they are lumpy and act in response to various commercial factors, but they are capable of providing reasonably firm volumes of demand response once committed. Small disaggregated loads using behavioural response are not firm and are less suitable for scheduling, but could be predicated in aggregate with reasonable statistical accuracy. Further, behavioural responses typically require advance notice which may inhibit their ability to be scheduled. By first identifying the loads that can be predicted with reasonable confidence, AEMO may reduce its need to implement complex scheduling arrangements.

Inverse relationship between firmness (and suitability for scheduling) and forecast-ability



AEMO currently receives DSP data that identifies loads that are price responsive. This information could be used to segregate load into elastic price responsive, and inelastic non-price responsive segments, with each forecast separately. This would enable AEMO to produce demand forecasts that capture an expectation of load response to price. Arguably this approach would improve the accuracy of existing demand forecasting that assumes negligible price and demand responsive loads that are in fact systemic and predictable. Over time the statistical rigour of the models would improve so that information about anticipated demand response is inherently communicated to participants in the demand forecasts. This approach to managing demand response in aggregate is likely to be more cost effective than require individual participants to participate in centralised scheduling.

To address concerns that AEMO does not have visibility of DR when making decisions during tight demand-supply conditions, retailers could be required to provide information about non-scheduled demand response when an LOR3 is predicted.

We encourage the AEMC to understand in more detail the issues AEMO is facing forecasting DR and whether there are less substantial measures that can be taken before requiring DR to be scheduled. Prior to developing a complex scheduling arrangement, AEMO should use data from the DSP portal to assess the impact of price responsive load, and identify exactly which type of loads could be incorporated in forecasting and managed using existing market tools such as FCAS and ramp rates. The remaining load could be considered for scheduling. We remain concerned that enforcing any significant obligations on DR at its early stage of development may inhibit increasing future value to both the market and customers.

Question 2 & 6: Customer interest in demand response

In our experience, C&I customers wishing to enter demand response contracts are contacting retailers to solicit offers.

EnergyAustralia does not have data to support a view on the volume of mass market customers that are seeking to access demand response products and services, but can provide some observations.

- The market has observed very little take up of time of use tariffs which offer benefits to customers that can shift their load. This suggests that without extensive customer education and engagement there is unlikely to be widespread adoption of demand response offers.

- The costs, and physical space requirements, for control technologies and batteries are likely to present barriers to entry for some customers.

- We have observed that following initial engagement, customer interest in participation declines over time without continued engagement by the service provider. The causes for this are not clear but could be due to a lack of realised value, or disinterest.

Question 2: Difficulties faced by third party providers & retailer incentives to offer demand response

The Consultation paper highlights that a key issue under the current framework is that it is difficult for third party response providers to participate due to the barriers to entry for becoming a retailer. The consultation paper lists the commercial skills of retailers as expertise in risk management, marketing, IT system administration and meeting prudential and consumer protection requirements. DRA areas of expertise are described as load production processes, dispatch and control technologies. Hence, it is argued, that it is difficult for third parties to participate in the current framework as they do not have the required expertise.

However, it is likely that DRAs would need to develop some expertise in retailer capabilities under a DRM. DRA's would need to develop billing (or crediting capabilities), IT systems to interface with AEMO's wholesale market systems and to receive and process meter readings, marketing and customer engagement, sales acquisitions. Depending on how non-compliance with dispatch targets is penalised, they may also require prudential obligations. As DRAs will have financial obligations to customers, there are likely to be specific customer protections that apply. DRAs are also likely to take up risk management strategies to access price stability.

It is therefore likely that DRAs will either need to develop the similar expertise to that of retailers, or enter arrangements with retailers, to access the expertise required to participate as a DRA.

The Commission have outlined reasons why retailers don't have incentives to develop demand response as they can cover peak loads using their generation assets. However, retailers are actively developing demand response and VPP assets to utilise within their energy portfolios. While some retailers may hold significant generation at certain nodes many hold a short position to the market, DR in this sense would be a highly valuable tool to manage exposure. Further, in an uncertain policy environment and changing market, demand response offers a solution to balancing supply-demand of their portfolio that can be developed faster than peaking generation.

Question 15: Appropriate Thresholds

Consideration should be given to the appropriate threshold for any regulatory changes to ensure the changes are suitable. Many of the options proposed are complex and costly when applied to mass market customers and may be better suited for large customers.

- For the DRM, the administration, complexity, costs and risks of billing customers on baseline usage are much more significant for mass market. Baselines are less accurate for mass market consumers and the costs of implementation are likely to outweigh any benefits.

- For the AEC proposal to negotiate DR contracts in good faith with third parties. This is too administratively and labour costly for retailers to negotiate DR for individual mass market customers.

Questions 9 & 16: Implementation timeframes and costs

- We consider it is too early to comment on expected timeframes and costs as these details are highly dependent on how the rule change proposals are progressed by the Commission.

- PIAC's suggestion that implementing changes in conjunction with 5 Minute Settlements/Global Settlements would reduce overall costs to retailers is incorrect. 5 Minute Settlements predominantly impacts energy trading and wholesale settlement systems, whereas the proposed DRM would have most impacts on retail billing systems. Given the different systems and business expertise required, these changes would likely be implemented separately with negligible savings from joint implementation. In fact joint implementation could increase risks and create resourcing pressures for businesses leading to increased risks for implementation delays or issues.