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10 December 2015

Arik Mordoh
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

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Dear Mr Mordoh

Stanwell Corporation Limited (Stanwell) welcomes the opportunity to comment on the Demand Response Mechanism and Ancillary Service Unbundling (DRM/ASU) consultation paper (Consultation Paper).

Stanwell supports market participation by both supply and demand resources on technology-neutral terms in order to ensure market outcomes are in the long term interests of consumers.

Demand Response Mechanism

While technology-neutral competition is beneficial, Stanwell notes that the DRM has already been subject to years of development and a cost benefit analysis which showed it is against the long term interests of consumers. The current proposal appears to differ only in respect of allocating certain costs as voluntary. Stanwell does not believe that such artificial distinction improves the proposed rule.

Pretending costs don't exist because they are voluntary, while claiming benefits from those voluntary actions, does not lead to robust decision making. Regardless, the exclusion does not address the fact that the DRM impacts on the wholesale market are significantly less than AEMO's implementation cost according to the cost benefit analysis already completed[1].

The rule change proposal appears to rest on a number of unsupportable assumptions

1. That demand side participation is stifled under the current market design,
2. That wholesale prices are inefficient and high enough to entice further competition to lower average prices for broader consumer benefit,

[1] *Cost-benefit analysis of a possible Demand Response Mechanism*, Oakley Greenwood, 9 December 2014, page 7. "Change in total generation sector costs" $0-2.6M NPV over 19 years, and page 60 *"AEMO estimated the costs it would incur in implementing and administering the DRM at somewhere in the order of $8 to $14 million over ten years (NPV)."*.

3. That a wholesale mechanism will be more effective in producing demand side participation in order to defer or cancel network spend than the existing network based incentives, and
4. That Demand Response Aggregators – whether new entrant or existing retailers – will offer substantially more beneficial terms to demand response providers than is currently available through retailers.

Each of these issues has been addressed in previous DRM processes but is again debunked in Attachment 1.

Stanwell also notes that the rule change proposal is for all demand response to be *non-scheduled*, which is a significant departure from the AEMC's conclusions in the Power of Choice review[2]. The resultant lack of transparency in the proposed rule can be contrasted against the strong desire for the provision of reliable information to the market discussed at length in a number of other rule change processes.

Inconsistent elements of the proposed rule change

The proposed rule appears to assume as a pre-condition the implementation of Multiple Trading Relationships in order to enable both the retailer and Demand Response Aggregator (DRA) to become Financially Responsible Market Participants[3], however Stanwell note that the AEMC have recently determined (in draft) not to proceed with this rule change[4].

It also appears inconsistent that the proposed Demand Response Aggregator (DRA) registration class would be afforded preferential treatment to generator registrations in respect of their need to register as a *Market Customer*. Generators are often required to register as a *Market Customer* where there is the potential for their auxiliary draw to exceed their instantaneous generation. The proposed rule change however does not require DRAs to register as a *Market Customer* against the possibility that their nominated demand response is not provided. We note that registration as a *Market Customer* creates a number of obligations in respect of other schemes such as the Renewable Energy Target and State-based energy efficiency schemes.

Stanwell also notes that the DRM proposal interacts with a rule change proposal that is being progressed separately yet concurrently, namely ERC0189 (DSO). Should the DSO rule progress it would exclude *market loads* greater than 30MW from participation in the DRM[5]. We do not consider it possible to address these rule change proposals separately.

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[2] AEMC 2012, Power of choice review - giving consumers options in the way they use electricity, Final Report, 30 November 2012, Sydney
"*Consumers can choose to participate in the DRM on a scheduled or non-scheduled basis, subject to any threshold requirements required by the rules or AEMO.*" page 116 and
"*To the greatest extent possible, consumers should be encouraged to participate as scheduled demand resources.*" page 117

[3] AEMO High level design – 30 July 2013, page 8.

[4] http://www.aemc.gov.au/Rule-Changes/Multiple-Trading-Relationships

[5] Any market load proposing to participate in DRM would be considered to be a market load which "varies, or may vary, in response to changes in spot price". Such loads >30MW would become scheduled through the DSO rule change and ineligible for the DRM.

New report confirms that proposed "savings for all consumers" are illusory

In conjunction with the rule change request, significant new information has been released in form of the the Brattle Group's International Review of Demand Response Mechanisms[6]. The report provides a comprehensive overview of international demand response and demand response mechanisms, but contains no support for the proposed DRM.

> ***Perhaps the simplest means of enabling DR in energy markets is to establish liquid wholesale markets with transparent wholesale energy prices, which NEM and the other markets (energy-only markets and markets with capacity obligations) we evaluated already do****. This enables the largest customers, who may be direct wholesale market participants, to reduce their consumption and save money when they observe prices rising above the maximum value that they obtain from consuming electricity. Other customers may do the same to the extent they are exposed to wholesale spot prices through retail arrangements [emphasis added].*[7]

Most significant is the report's conclusion that where demand response reduced wholesale prices:

> *… customers benefit from reduced system prices,* ***but these are transfer payments from producers and do not represent a reduction in total system costs****…* ***Transfers from producers to consumers cannot be sustained in the long run*** *because prices will have to cover the cost of new generation entry, with or without demand response. Generators may also perceive high regulatory risks if policy makers appear to pursue policies aimed at suppressing prices rather than improving efficiency, thus raising the cost of investing.*
>
> *The design of both the Singapore and FERC approaches seems to have been influenced by the claim that all loads benefit, in the short term, from reduced wholesale prices as a result of DR integration. However, the design of these approaches does not take account of total (producer and consumer) surplus or total resource costs, so* ***will lead to less economically efficient outcomes*** *[emphasis added].*[8]

This finding is consistent with recent statements from the Commission[9] but contrary to claims made in support of the proposed rule change and the DRM cost benefit analysis.

The Brattle report also states that demand response in both capacity and energy only markets is in the order of a few percent of maximum demand. As shown in Attachment 1, observed demand response in Queensland is at least equal to this under current market design, countering the claim that an alternative mechanism is required to incentivise participation.

The report also concludes that

- capacity markets typically have higher penetration of demand side participation than energy only markets,

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[6] *International Review of Demand Response Mechanisms,* Brattle Group, October 2015

[7] *International Review of Demand Response Mechanisms,* Brattle Group, October 2015, p iii.

[8] *International Review of Demand Response Mechanisms,* Brattle Group, October 2015, page 77

[9] For example the 2015 Residential Electricity Price Trends national fact pack, page 1 (green section).

- demand side participation in scheduling is rare even where enabled,
- differences in dispatch and settlement timeframes can affect incentives, and
- when volatility is low, so is the value of demand participating in the energy market.

These conclusions are no surprise to Stanwell and are unlikely to be contentious.

Ancillary Service Unbundling

Ancillary Service Unbundling (ASU) appears to be an adjunct to the DRM rule change proposal, adopting the assumption that third party facilitation may "unlock" latent competition. The current rules already allow for *market loads* to be classified as *ancillary service loads*, but it is likely that uptake has been minimal for the same reasons as the registration of *scheduled loads* – that the obligations associated with registration significantly outweigh the potential commercial benefit for most consumers.

The ASU proposal is interlinked with the DRM proposal and the Multiple Trading Relationships (MTR) proposal. The key issue is who can submit what offers and how precedent is determined between offers.

Under current market design, the *Market Customer* may offer ancillary services from *market loads* with appropriate communications and/or telemetry. Where ancillary services and energy services are both offered, AEMO is able to co-optimise the offers received to ensure the lowest cost to consumers while ensuring that response (whether from load or generation) is not double-counted.

Under the proposed DRM and ASU model (with MTR), a *Market Customer* or *Demand Response Aggregator* may offer ancillary services from *market loads* with appropriate communications and/or telemetry. Where ancillary services and energy services are both offered, these services may be offered by separate participants. It appears likely that AEMO would need to adjust its systems to be able to co-optimise the offers received to ensure the lowest cost to consumers while ensuring that response is not double-counted. The proposed design appears to prioritise *DRA* nominations over *Market Customer* nominations[10], although this contradicts AEMO's co-optimisation approach.

From this analysis of what currently exists and what is proposed, it is unclear to Stanwell how the proposed rule change would significantly incentivise additional ancillary service provision.

We also note the anecdotal evidence from AEMO that registration interest in the provision of FCAS has increased in South Australia following the recent high price events, rather than in response to regulatory intervention.

[10] "*Market Customers (retailers) will not be able to provide FCAS with a load if the load has also been classified by a DRA for demand response*". AEMO DRM High level design, page 13

Link to AEMC's Integration of Storage Discussion Paper
Storage devices may be a future source of ancillary services (or demand response) when aggregated together through the Small Generator Aggregator registration category. The current rules however do not allow Small Generator Aggregators to provide market ancillary services. As a result, the recent AEMC Integration of Storage Discussion Paper stated that

> *The Commission considers that there is cause to extend the provision of ancillary services to other parties, eg, allowing small generator aggregators to provide FCAS[11].*

This may be a simpler approach to facilitating ancillary services when compared to the proposed rule change.

The Commission's other findings in the Storage Discussion Paper overwhelmingly emphasised a market-based, technology neutral approach to change. This does not appear to be consistent with the proposed rule change which is biasing one type of participant against another.

> *In undertaking any assessment of whether the regulatory framework remains fit for purpose in the face of dynamic market forces, it is important to understand the original purpose of that framework. An underlying principle of energy market regulation in Australia has been technology neutrality. That is, the rules are not designed to bias the deployment of storage or any other technology. Rather the rules have been designed to encourage efficient, market-based outcomes and so not act as a barrier to the use of whatever technology delivers the most cost-effective service[12].*

Apart from minor changes (such as allowing the Small Generator Aggregator registration category to provide ancillary services as stated above) the AEMC concludes that the current regulatory frameworks are, overall, robust enough to facilitate the large scale integration of batteries (and therefore their demand response and ancillary services).

> *The AEMC's preliminary findings therefore suggest that the current regulatory frameworks and associated processes for developing them, can accommodate the installation of storage across the electricity sector and are largely robust to this type of technological change[13].*

[11] AEMC Integration of Storage Discussion Paper, Page 21, October 2015
[12] AEMC Integration of Storage Discussion Paper, Page i, October 2015
[13] AEMC Integration of Storage Discussion Paper, Page iii, October 2015

Conclusion
Stanwell does not consider that the DRM and ASU proposal identifies a material issue in market design, and does not consider it to be in the long term interests of consumers. Stanwell encourages the Commission to recognise that significant price responsive demand side participation is already occurring in the NEM, that the recent Brattle Group report does not support DRM, and that the AEMC's own storage review acknowledged that this major new source of DRM and AS can be accommodated within the current market frameworks.

If this issue must continue to be investigated, Stanwell suggests that a working group be formed to consider how to incorporate demand side participation into market mechanisms, including central dispatch. A single review or working group could provide a holistic consideration of a number of related and overlapping issues. These include the market transparency and participation concerns under ERC0189 (DSO), the access to market issues under ERC0186 (DRM), the proposed non-scheduled generator rule change and the emerging issue of aggregation of small demand side resources (such as batteries) into larger market responsive portfolios.

If you have any questions relating to this submission, please contact me on (07) 3228 4529.

Yours sincerely

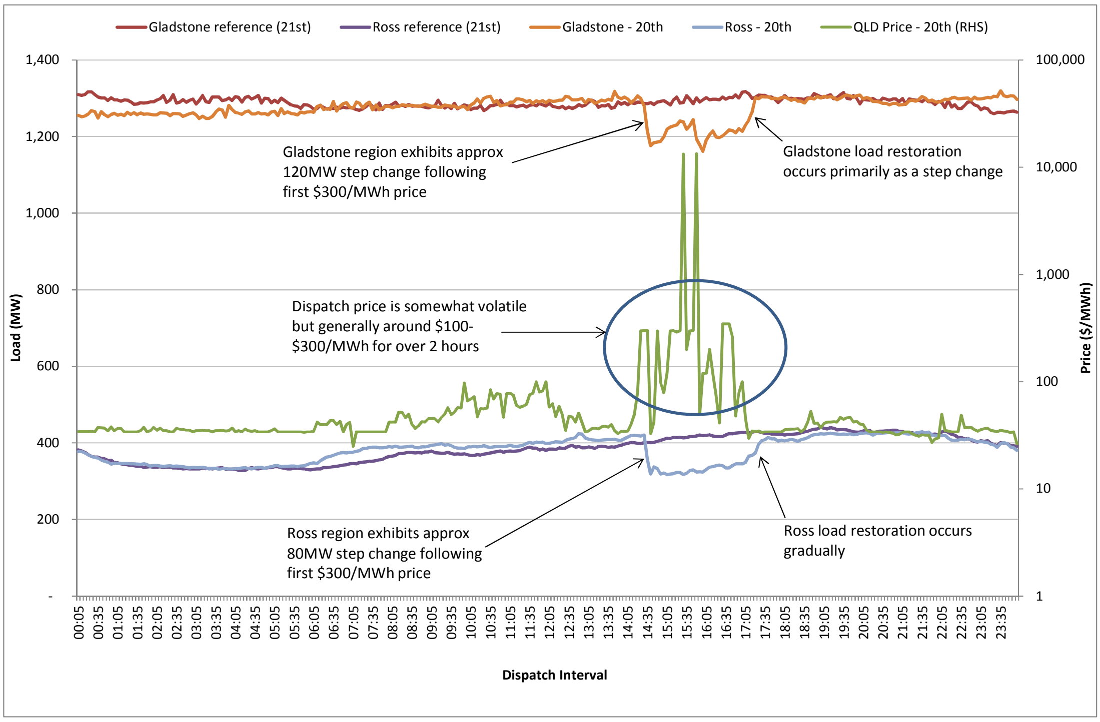
Luke Van Boeckel
Manager Regulatory Strategy

Attachment 1. Fatal flaws analysis of the proposed DRM

1. DRM is not required for demand side participation

Demand response can, and does, occur under the current market design. From Stanwell's experience the most prevalent form of retail contract is a fixed price, load following product which will typically have an allowable variation in consumption from a baseline estimate – for example ±20% per annum. For large loads, an alternative arrangement is a pool pass-through retail agreement supplemented by financial hedge contracts. Under either arrangement, consumers have the ability to curtail consumption either unilaterally or in agreement with their retailer.

The rule change proposal indicates that the current arrangements are not enabling customer participation in the wholesale market, however observable market information proves this to be incorrect. The charts below show the demand for two sections of the Queensland grid on 20 November 2015, a day when demand was relatively high (around 8000MW) and prices were volatile both in predispatch and dispatch. It can be observed that approximately 200MW of demand response occurred, which at roughly 2.5% compares favourably to international markets[14].



This reduction is observable as a significant step change (>80MW) in response to moderately volatile market prices. Stanwell believes that there are a number of other sources of demand response which are smaller or activate only at higher market prices. Indeed the greatest inhibitor of demand side participation in the current market has been sighted as the lack of high prices and volatility, and therefore, commercial return.

[14] *"Load reductions attributable to price-responsive load in the energy-only markets we surveyed ranged from about 1% of peak load in Texas to more than 2% in Alberta, although the exact amounts are difficult to determine" International Review of Demand Response Mechanisms,* Brattle Group, October 2015, p iii.

The over-supply has resulted in historically low wholesale market spot prices, and a reduction in price volatility – and because of the combination of these factors, significantly less revenue available over the course of a year from demand reductions that are undertaken at or above the level of price at which DR generally enters the market.

In short, these are not particularly encouraging times for DR.

These conditions are not entirely bad for consumers, however. Low and relatively stable prices are very good for electricity consumers, at least in the short run. However, where those prices do not allow generators to operate at acceptable commercial returns they can threaten the attractiveness of investment which can create higher and more volatile prices for consumers in the future.[15]

2. **DRM cannot efficiently reduce wholesale prices which are inefficiently low**

In addition to the statement from Oakley Greenwood above, the cost benefit analysis performed in 2014 states:

As has been the case in most market simulation modelling undertaken in the past several years, various adjustments needed to be made due to the significant over-supply of generation capacity in the market. ***The basic problem is that the combination of the over-supply of generation capacity, the forecast softness of demand growth and the existence of the RET result in unsustainably low wholesale market prices.*** *Generators have already responded to this by removing or reducing the operation of capacity in order to better balance supply with demand and thereby raise prices to levels that provide minimally adequate returns.*
In our analysis, we ensured that wholesale electricity prices were plausible (i.e., would provide at least minimally sustainable profitability levels for all operating generators over the analysis period) by balancing the amount of coal, gas and renewable generation in the market. ***This required withdrawal of both coal and gas capacity and a reduced (and floating) level of renewable generation.*** *Withdrawal of coal and gas capacity was informed by assessment of the profitability levels of specific plants.* ***In addition, in practice, the approach taken meant that the full LRET quota was not met in the modelling.*** [emphasis added] [16]

In short, Oakley Greenwood had to increase wholesale prices to provide "minimally adequate returns", from which the DRM modelling reduced by between $0.26/MWh and $0.73/MWh. The net impact is therefore an *increase* in wholesale prices, since the uplift from forced plant retirement (decreased competition) is greater than the reduction from DRM ("increased competition"). With LRET not met, retail prices would also rise significantly to encompass the penalty payments required of retailers.

As highlighted in the Brattle report, simply reducing wholesale prices in the short term is not efficient, and may not be in the *long term* interests of consumers as required under the NEO.

[15] *The Impact of Late Rebidding on the Provision of Demand Response by Large Electricity Users in the NEM*, Oakley Greenwood, 25 November 2014, page 29
[16] *Cost-benefit analysis of a possible Demand Response Mechanism*, Oakley Greenwood, 9 December 2014, page 3.

3. **A Wholesale DRM is unlikely to create network benefits**

Given the incentives already in place for networks to procure, and customers to provide, network support services through demand management, Stanwell is highly dubious of the proposed “network benefits” under the DRM.

Stanwell also considers that initiating a wholesale market mechanism to drive uptake of network support solutions is likely to be a highly inefficient endeavour given the network based solutions that already exist.

On 20 August 2015, the AEMC made a final rule to help balance the incentives on distribution businesses to make efficient decisions in relation to network expenditure, including investment in demand management[17]. This further augments the incentives for load to provide network support where it is capable of doing so and would be of benefit to the system.

Network companies typically contract demand management in order to gain confidence that the response will be available if required and typically the non-firm nature of the response is accounted for by purchasing more demand management than would be required from a firm source.

Stanwell understands that such contracts typically exclude the provider from actions which would reduce the potential availability of the demand response – for example in current battery trials, only a portion of capacity is available for market response while the remainder is held for network support.

Stanwell understands that the cost of these contracts forms part of the Regulated Asset Base as it is replacing expenditure on network solutions which would otherwise go into the RAB. As noted in the cost benefit analysis the networks also retain a proportion of the net savings achieved compared to investment in network assets. The cost benefit analysis performed by Oakley Greenwood in 2014 appears to assume no cost associated with the networks contracting demand response, and does not appear to consider the possibility of mutually exclusive arrangements for wholesale and network support demand response.

4. **DRM is unlikely to create greater arbitrage benefits to DR providers than currently exist**

The proposed DRM treats DRAs as a virtual non-scheduled generator. This can only create value for the aggregator if the demand response occurs but the wholesale price remains high.

The consultation paper and supporting documents cite existing retailer-agreed arrangements which allocate demand response providers 50% of the pool revenue associated with their demand reduction. The cost-benefit analysis states that

> *Because the exercise of demand response will constitute the primary focus of the third-party DRAs that will be empowered by the DRM, they can be*

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[17] http://www.aemc.gov.au/Rule-Changes/Demand-Management-Embedded-Generation-Connection-I#

> *expected to offer higher levels of arbitrage to DR providers, and to call for their dispatch more regularly…*[18]

Given that the DRA will have more incremental cost than a retailer (who need not notify AEMO of a demand side event), and no other revenue streams or portfolio benefits apparent under the DRM proposed design, it is difficult to reconcile the statement that they will be expected to offer higher levels of arbitrage than current arrangements.

In relation to specialist DRAs calling for dispatch more regularly, Stanwell expects this to be so, however we note that demand response providers have indicated the undesirability of curtailing consumption (and therefore production) in relation to events where high prices do not eventuate, or do not sufficiently compensate for the activity.

> *Some interviewees also reported that repeated requests to dispatch when the predicted high-priced event does not materialise and/or when one such event is missed (because it appears too late in the Trading Interval) causes frustration from within their company. The increased risk and transaction costs that were reported in some cases make the end-use customer reconsider offering DR at all.*[19]

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[18] *Cost-benefit analysis of a possible Demand Response Mechanism*, Oakley Greenwood, 9 December 2014, page 5

[19] *The Impact of Late Rebidding on the Provision of Demand Response by Large Electricity Users in the NEM*, Oakley Greenwood, 25 November 2014, page 3