10 December 2015

Mr Arik Mordoh
Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235

Dear Mr Mordoh,

RE: CONSULTATION PAPER - *NATIONAL ELECTRICITY AMENDMENT (DEMAND RESPONSE MECHANISM AND ANCILLARY SERVICES UNBUNDLING) RULE 2016*

ERM Power Limited (ERM Power) welcomes the opportunity to respond to the Commission's Consultation Paper *National Electricity Amendment (Demand Response Mechanism and Ancillary Services Unbundling) Rule 2016* (ERC0186).

About ERM Power Limited

ERM Power is an Australian energy company that operates electricity generation and electricity sales businesses. Trading as ERM Business Energy and founded in 1980, we have grown to become the fourth largest electricity retailer in Australia, with operations in every state and the Australian Capital Territory. We are also licensed to sell electricity in several markets in the United States. We have equity interests in 497 megawatts of low emission, gas-fired peaking power stations in Western Australia and Queensland, both of which we operate.

General comments

Overall, we are disappointed that this rule change request has been made and yet more time has been, and will be, spent on the concept of the Demand Response Mechanism (DRM). After a year spent by AEMO on technical capabilities in 2013 and two cost-benefit analyses that showed no material wholesale benefit it is a shame that we must again turn our minds to this issue in an already crowded reform space. There is no compelling case that the DRM will meet the objectives of the National Electricity Objective (NEO); in contrast, we contend that the proposed solution will add complexity, risk and ultimately cost inefficiencies that will ultimately be borne by customers.

However, we appreciate that the task before the Commission is to form a conclusion on a rule change proposed by the COAG Energy Council.

Before providing our responses to the Commission's questions, we:

- discuss ERM Power's view that the case for change is not there;
- explain and contextualise these views within ERM Power's experience as a major demand response service provider; and
- provide commentary on the Commission's analytical framework.

The case for change is not there

The analysis that supports the proposed rule change does not demonstrate that the DRM will improve the amount, quality and reliability of demand response in the National Electricity Market (NEM):

- There is no evidence that there will be a sustainable or cost-efficient methodology to deliver securely supplied energy to consumers over the long term.
- There is also no evidence of market failure.
- Consultation to date on this issue has failed to recognise that demand response is currently widely available and routinely deployed throughout the NEM.
- There is no evidence that barriers to demand response actually exist. Demand response arrangements are already common in NEM and a number of service providers are offering innovative technology and information solutions to end users.

The complicating factor in this is that the true extent of demand response is opaque for the casual observer: many of the arrangements are commercial in confidence and a range of service providers – including but not limited to energy retailers – provide the service. However, this does not mean that demand response needs are not being met. Appendix A contains a number of examples of recent demand side participation in the NEM across all regions and multiple days. These examples clearly indicate that large blocks of demand response are currently available and actively deployed both on an absolute megawatt and percentage of demand basis. These examples by no means provide an exhaustive listing of observed demand response events in the NEM and should be viewed by the Commission as merely samples of demand response that is observed on a routine basis. It is also worth noting that those regions that have historically experienced a greater frequency of spot price volatility also experience a similar increased frequency of demand response activity.

For the past three years we have observed the case put for the DRM by its proponents as anecdotal and concept-driven. Evidence that demonstrates a net cost or insufficient benefit has been ignored or recalibrated as industry special interests protecting their patch. However, we can move beyond the political contest of the competing stakeholder claims to observe key and observable facts that show that the DRM as proposed in the rule change is not fit for purpose for the NEM for the foreseeable future:

- The market is generally oversupplied with generation (to the extent that several units are currently mothballed), and additional generation as a result of the RET will be added over the next five years. Additional investment in the form of a complex DRM initiative can only add further inefficiency to already stressed generation returns.
- The majority of NEM regions have experienced very few prices above $300/MWh for a number of years, reducing the economic benefit of the DRM.

Leading from this, in its cost-benefit analysis of the DRM for the Energy Council, consultant Oakley Greenwood demonstrated (under feasible scenarios) that:

> …impacts in terms of reductions in total generation sector costs is minimal in both the AEMO forecast and AEMO forecast plus CRNP scenarios. It is also the case that all of the generation sector cost reductions in

both of those scenarios are due only to reductions in fuel (and other variable operating and maintenance) costs, rather than reductions in capacity requirements or capacity costs.[1]

Oakley Greenwood found that any material benefit from the proposed DRM might potentially come only from increased network efficiencies, noting that this still 'depends to a large extent on the number and nature of pricing and DR activities undertaken by the networks themselves' (p.16). We note that indications to date are that the networks have taken action to address the issue without a DRM needing to be in place. This is clearly identified by the reduction in identified future network augmentation in the transmission and distribution annual planning reports. Power Factor Correction programs have also reduced demand on networks across the NEM.

Despite the lack of evidence that reductions in generator sector costs were material, Oakley Greenwood did state that a DRM could result in a 'downward pressure on wholesale electricity prices'.[2] However, even this soft concept is unproven and therefore remains a theoretical argument. If we assume that the DRM is implemented and is successful on its own terms (which we do not believe it can be), lower wholesale prices may hold at best for only short periods of time, as evidence also exists that such a mechanism may contribute to longer term price increases. Significant enough load curtailment (which may be as little as one large industrial customer at one node) can lead to reduced periods of high volatility. However, this also means a stripping out of generation value: we have also seen the gradual closure of coal-fired baseload generation, with a recent example being Alinta announcing the imminent closure of its SA Northern plant due to extensive economic loss. As a result, contract prices post the Northern closure period have roughly doubled in many forward contract periods. None of this is to say that demand response, closure of inefficient plant or that renewables do not have their place. We must, however, be clear that an unintentional side effect of these elements may be increased power prices for consumers as a whole, not the mooted reductions of the DRM proponents.

Of course we should also recognise that the DRM is naturally self-constrained on any large scale for the same reason: if successful on its own terms as above (where spot volatility is removed) this in turn removes the economic viability of the proposed Demand Response Aggregator (DRA).

ERM Power's experience as a major demand response service provider

ERM Power's retail business (ERM Business Energy) is currently the fourth largest retailer in Australia, and retails only to business customers. We have what is arguably the largest and most successful demand response program in the NEM, spread across all interconnected states and territories. This puts ERM Power in a good position to provide commentary on the current conditions for demand response initiatives and consumer sentiment.

In our experience we have seen no evidence that separate agreements with DRAs will add or create value. ERM Power currently has commercial arrangements with several demand response aggregators to recruit and remotely control customer demand response. The arrangements have been meaningful and agreeable to all, including customers. We have seen no evidence of the alleged additional value that would come from providing a DRA with its own market status.

---

[1] Oakley Greenwood (2013) *Cost-benefit analysis of a possible Demand Response Mechanism*, Final Report for the Department of Industry, December, p. 7.

[2] See Oakley Greenwood (2013) *Cost-benefit analysis of a possible Demand Response Mechanism*, Final Report for the Department of Industry, December, p. 16.

Our experience as a provider of demand response services to business customers contradicts the statements by the Energy Council as quoted in section 3.1.1 of the Commission's paper (pp. 10-11). For example, on page 10 it is stated that large customers have two options to choose from to be exposed to the wholesale market:

> 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.

This is not correct. ERM Power provides several alternative structures, including fixed capacity payments for access to customer's demand response, customised time of use tariff structures, and spot sharing arrangements. We also note that demand response contractual options exist for customers where they retain the right and the ability to control their own demand side participation. There are a number of service providers that currently provide real-time market data and demand alerting services, where these are extremely low cost solutions. A simple on-line search identifies Global Roam, Creative Analytics, Phanalytics (Sparky Pro), Neo Mobile and Electricity Pro as information providers in this area. ERM Power also provides a real-time price alerting service to its customers.

Page 11 of the consultation paper notes the Energy Council's claim that 'large users have also reported that the terms offered on demand response contract are generally not attractive'. While it may be true that these claims have been made, we question the depth of analysis behind this statement: what is the significance of this sentiment across the broader large user population and what terms are seen to be required to be 'attractive'?

It is fair to acknowledge that several of the NEM states have undergone long periods without market volatility, largely due to falling energy demand and an oversupply of generation. Naturally during these periods of oversupply, the economic reward able to be offered to customers will be lower – this is demonstration of market economics at play, not evidence that retailers are not offering commercially competitive demand response terms. ERM Power's experience as a demand response aggregator is that customers tend to prefer to be called to curtail load less frequently and with high certainty regarding start and finish times; the ability to contract with fast-start at call demand response is not common and most demand response requires a time delay period in initiation. NEM pool prices can be difficult to predict, therefore a higher value is placed on demand response capability that can be initiated instantly via remotely controlled technology, relative to capability that requires manual intervention and advanced notification. The prevalence of five minute price spikes in Queensland is a practical example of where fast-start demand response, where it can be obtained, is of higher value than delayed start.

In ERM Power's experience the largest barrier to a customer participating in demand response programs is the customer's risk appetite, which may be reflected in their willingness to interrupt operational processes or utilise their generation; or the technical requirements associated with making their standby generation available to the market. The consultation paper has failed to identify this key point, and the proposed rule change will not address this genuine barrier.

It is worth noting that in some instances the larger vertically integrated generator-retailers may be motivated to offer attractive retail contract terms to customers in order to take their demand response capability *out* of the market. This is because they are naturally motivated to ensure wholesale market prices remain high to preserve the value of their generation assets and prices of futures contracts struck with retailers. That is, they will offer more attractive headline rates to customers in order to control the initiation of their demand response during high price events. This approach is purely a commercial strategy, and one that a customer with demand response capability needs to understand and value. Essentially such contracts provide an upfront payment, via a contract discount, for the right to control the demand response capability. These arrangements subtly provide customers with a commercial incentive not to curtail load. It is important to note the introduction of a DRA into the equation will not subvert this strategy.

ERM Power's response to the Commission's NEO assessment framework

The Commission has proposed an assessment framework for the DRM rule change proposal as shown in Table 1 below. This is a framework to assess the proposed DRM rule change for its alignment with the NEO. We have provided ERM Power's perspective on each element of the framework below, concluding that the DRM as proposed does not meet the NEO criteria in any demonstrable way, and may, in fact, bring about a range of undesirable and unintended side effects.

Table 1: Commission's proposed assessment framework for alignment with the NEO

Elements of the framework	ERM Power response
Assist in determining the lowest cost dispatch of scheduled electricity load, generation and ancillary services in order to balance supply and demand.	We see no evidence that the proposed DRM will achieve this outcome to any degree. Demand response already exists widely throughout the NEM. If implemented, DRAs should face the full costs of the rule change, as this is the only justifiable way to demonstrate a DRA brings market efficiency (user pays system).
Incentivise electricity users to make decisions to use electricity at times when the value of its use exceeds its underlying cost.	We see no evidence that this will happen more than it does now. Customers already have the opportunity to curtail load, and do so when economic signals warrant it.
Send better signals to market participants to invest and maintain the electricity system.	Again, this is unlikely. In fact, if the DRM was successful on its own terms, system reliability issues will emerge if the economic signal for the provision of firm peaking generation is removed from the market.
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.	The proposed DRM will result in system-wide costs because AEMO at the least will need to implement systems; the prudential requirements for DRAs is weak; and system reliability is also potentially at risk as above.

As a final point, we note that the Western Australian Public Utilities Office is reviewing the rules on how demand response operates within the South West Interconnected System.[3] The rule consultation recognises that the current value of demand response is lower than traditional generation and highlights a number of inefficiencies that have arisen from demand response which are resulting in higher costs to consumers.

---

[3] See Public Utilities Office (2015) *Position Paper on Reforms to the Reserve Capacity Mechanism*, Department of Finance, 3 December.

Please contact me or Jenna Polson on (03) 9214 9347 if you would like to discuss this submission.

Yours sincerely,

[signed]

David Guiver
Executive General Manager - Trading
07 3020 5137 – dguiver@ermpower.com.au

RESPONSES TO SPECIFIC QUESTIONS

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

2.1 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?

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

2.3 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?

Consultation to date has failed to recognise that demand response is currently widely and frequently initiated throughout the NEM. There is no factual evidence to demonstrate that barriers currently exist. ERM Power currently has identified no regulatory barriers to its own use of demand response.

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

The Commission needs to be mindful of the overall supply-demand balance of the NEM. Currently there is an oversupply of conventional generation in all regions of the NEM, with several units mothballed and the potential closure of some uneconomic generation. The penetration of additional intermittent generation (renewables) due to the RET with its inherent lack of reliable output will draw out the need for additional responsive generation such as fast-start peaking power stations and/or demand response. While additional demand response will arrive when it is economic to implement, it also needs to be recognised that demand response almost always has reliability limitations: load can only be interrupted for so long due to the limited ability to interrupt business processes for extended periods, and available fuel supply for small standby generation limits their ability to operate for extended periods. Therefore peaking generation will require sufficient economic signals to remain in the system to ensure reliable supply to consumers.

2.5 Might there be any unintended consequences from addressing such barriers?

As barriers to entry of efficient demand response do not exist there would only be consequences if the Commission seeks to change the NER to facilitate the entry of inefficient or uneconomic demand response. If that is the case, system reliability and possibly security issues will emerge if the economic signal for firm peaking generation is removed from the market.

The overall DRM design proposal

3.1 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?

Including demand response in dispatch forecasts and dispatch pricing outcomes will likely lead to less accurate outcomes than is currently the case. This is because the non-firm nature of demand response (including under the proposed DRM) makes it difficult to forecast with any accuracy. Demand response participants will experience significant availability variances from day to day, half hour to half hour. Examples include fuel limitations, inability to interrupt operations on a constant basis (such as production/output requirements, batch runs, seasonality, work-force limitations, process restrictions), time of use profile (for example, an office building may be able to offer demand response between 8am-6pm by reducing its consumption as settled in the market by operating standby generation behind the meter, but it will not be able to offer outside of these hours as the actual load is lower than their demand response capacity).

3.2 Would the proposed DRM generate useful demand-side information in relation to improving the management of transmission constraints through the dispatch process? How significant would this improvement be?

The proposed DRM would not create information or opportunities that do not already exist under the current rules.

Constraint issues are often local and therefore managed through targeted, more reliable programs. Management of network constraints requires the *real time* targeting of generation dispatch to ensure secure operation of individual network elements. Ad hoc use of demand response which is not dispatched in a controlled manner has the potential at critical times to increase rather than alleviate congestion in the network which then requires additional response from scheduled generation.

3.3 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?

AEMO currently calculates in real time the requirements for ancillary services based on a number of factors which include generation output, load at risk due to current network conditions and other factors. It is extremely unlikely the provision of demand-side information would improve AEMO's current processes to any meaningful extent.

3.5 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?

ERM Power believes that gaming risk and unintended consequences are likely to be significant on a number of fronts:

1. Where a retailer or customer is directly exposed to high wholesale pool prices they are strongly motivated to reduce 'actual' demand in order to achieve a financial benefit directly relating to that reduction in demand. Where a DRA is exposed to an outcome benchmarked against a baseline, the DRA is motivated to maximise this baseline and correspondingly maximise the 'observed' demand reduction. That is, a retailer has a real market position and would seek to reduce their actual exposure, whereas a DRA has no market position and could seek to maximise the 'observed' demand reduction. These are distinctly different drivers, and with high economic reward from a $13,800/MWh pool price, DRAs are likely to be tempted by gaming opportunities such as ramping demand up in advance of anticipated demand response periods, and load shifting between meters.
2. With greater transparency of the scale of demand response available, it would be rational for generators to increase the rate in which they target high prices in the last five minutes of a trading interval. Rebidding activity to 'get through' a period of demand response and push the prices up will be more likely where the demand response for a period can be observed and accounted for.
3. The potential also exists for generators to bid in manner that exposes DRAs economically, that is to oscillate between high price when demand response has not been initiated and low (or

negative prices) when demand response has been initiated. This risk also highlights the need to place stringent prudential requirements on DRAs.

3.6 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?

As stated above we believe the net effect will be system-wide cost rather than benefit, and that the network effects are unrelated to the wholesale market measure under discussion.

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

The ability of AEMO to manage the secure operation of the power system relies on AEMO's ability to control flow over critical network elements in real time. The actual network elements subject to this control requirement can vary on a trading interval and in some cases a dispatch interval basis. The initiation of demand response could be beneficial in some circumstances, if this demand response is located exactly in the right place in the network. However, there is also the risk that this demand response may be located in the wrong place in the network and when initiated may lead to the overload and failure (tripping) of a critical network element at a time of power system stress. This could then lead to involuntary load shedding, and in a worst case scenario cascading failure of multiple network elements.

Accredited baseline consumption methodologies

4.1 In stakeholders' views, are there any alternative demand response mechanism options that would not require the use of baseline consumption methodologies?

The NEM currently relies on sophisticated metering for accurate measurement of large customer consumption and export. To allow a baseline methodology based on 'simple mathematics', as described by the Commission on page 26 of the consultation paper reflects a degradation of standards that facilitates gaming and adds risk to market participants. Anything less than measuring through a meter that is accurate for the purpose of market settlements is unacceptable. Certainly any subjective calculation process that involves large amounts of money must have a robust appeals process for all parties.

4.2 What might be the costs, benefits, and consequences from having an administrative baseline developed and then managed by AEMO?

The proposed demand baseline methodology will encourage gaming, as addressed above.

The complexity in calculating and administering baselines should also be understood. Baselines will have to be administered on an individual facility (meter) basis, given the unique factors that influence individual customer demand profiles. The administrative costs for AEMO in managing this should not be under-estimated.

4.3 What are stakeholders' views on the proposed baseline methodologies, and the proposed assessment criteria to be applied when assessing baseline consumption methods?

The proposed methodologies for the calculation of baselines given the variability in customer load use are an inadequate solution for the NEM. Attempting to implement calculations that attempt to average out this variability will always result in a low level of accuracy for any calculation and create for each circumstance of their use a winner and a loser. Given that the market price cap for the NEM is extremely high, this adds significant risk to participants, particularly retailers. This in turns adds costs to end users as retailers seek to manage risk through prices to consumers. The approach will by definition reduce market standards and therefore investor confidence.

Restrictions on the provision of demand response

5.1 In stakeholders' views, how effective would the proposed DRM design be in preventing the exercise of potential gaming opportunities?

As discussed above, we believe that the proposed DRM actually incentivises gaming rather than preventing or even inhibiting it. If gaming was to be managed, AEMO and the AER would need to implement resource-intensive processes to monitor and enforce such controls. The NER would also need to ensure that gaming of the baseline is designated as a civil penalty provision similar to other areas of the NER. Any cost-benefit analysis undertaken by the Commission would need to include for costs associated with monitoring and enforcement of these provisions.

5. 2 Are there alternative options to improve upon the current design to manage gaming risks?

There are no alternative measures in ERM Power's view. Relying on subjective ('simple') mathematics such as a baseline will encourage gaming. As stated above, anything less than an interval meter read process at the appropriate standard is not appropriate for the NEM.

Interactions with demand side participation mechanism

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

The proposed rule change does not identify any additional demand response opportunities that are not already available in the NEM. In fact, the spot payment arrangement proposed may limit the products offered by a DRA when compared to a retailer that offers spot and capacity based structures.

Prudential requirement

7.1 Are the proposed prudential requirements on DRAs and retailers appropriate?

We do not believe the proposed prudential framework for DRAs is appropriate. Specifically, we suggest that it is does not account for the dynamic nature of the NEM. Currently demand response is usually deployed during periods of pool price volatility and often leads to periods of negative pool price, particularly where a large proportion of demand response exists (for example, in South Australia). This means that DRAs will be vulnerable to negative pool price settlements; as a result they will therefore often be required to make large settlement payments to AEMO.

The proposed framework will also encourage generators to target DRAs through the oscillation of extreme high and extreme low (negative) prices. DRAs should therefore be subjected to a high standard of prudential requirements.

Settlement charge

8.1 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? 8.2 Do stakeholders have any observations regarding the proposed changes to the compensation cost recovery from retailers? 8.3 Do stakeholders have any observations regarding the proposed changes to the way the operating costs would be recovered from DRAs and/or retailers?

The ongoing total cost of the repeated calculations of baselines and calculation of modified settlements associated with demand response intervals will be greater than the current costs for settling the NEM. These additional costs will not be trivial, and will be required to calculate initial baselines regardless of whether demand response events occur or not. These additional costs should not simply be smeared across all NEM participants. AEMO should separately calculate these costs and the costs should be paid for by DRAs. As this service is being created to facilitate entry of DRAs into the NEM, DRAs should be required to pay a fixed weekly fee for the service in addition to the fees as set out in Table 5.3 of the Commission's consultation paper.

Implementation issues in relation to the DRM/Voluntary and staged approach

We note that questions 9 and 10 are identical and have addressed these below.

9.1/10.1 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?

The voluntary approach appears to be a way to take a bad idea (that is, the DRM) and make it more palatable to those who oppose it. It is a political compromise rather than a policy enhancement: making the DRM voluntary does not make it a better idea or more appealing. It also does not remove the additional costs imposed on AEMO to facilitate its introduction. No added benefits or product opportunities have been identified in the proposed DRM that are not already available in the market to end-users under the current rules.

9.2/10.2 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?

Manual billing will be the only viable solution, both short and long term. If implemented, AEMO will quickly discover that customers have unique and highly variable consumption patterns on a day-to-day basis, and baseline calculations will only be able to be supported by an individually calculated and interpreted manual processes for each and every demand response interval and customer.

Potential barriers to demand side participation in FCAS markets

11.1 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?

The question as framed may be leading to an incorrect assumption in that the Commission assumes FCAS market participation is limited to participants that purchase or sell electricity on the wholesale spot market. This is not entirely true: the provision of FCAS services is more accurately defined as currently limited to those participants who can meet the technical requirements of the MASS and receive active five minute dispatch instructions from AEMO.

Currently FCAS providers are paid on an enablement basis with an after the event auditing of actual response. The audit process is based on actual dispatch outcomes compared to the five minute dispatch instruction to the FCAS provider and what the dispatch outcome was expected to be had the FCAS event not occurred. Without this ability to assess actual outcomes versus dispatch targets, an auditing process would not be possible. Therefore it is this need for this technical audit process to confirm a service has actually been supplied that creates the barrier to entry. This audit process needs to exist regardless of the type of participant providing the FCAS response.

Currently FCAS contingency service providers are audited based on response assessed as deviation from dispatch targets. Dispatch targets cover only a five minute period. For both the fast (six seconds) and slow (60 seconds) response this generally only encompassed one, or at the most, two dispatch intervals, as at the next available dispatch interval AEMO automatically calculates new dispatch targets to rebalance supply and demand. The delayed (five minute) response allows for control action via a controllable input to the provider's control system to maintain actual output either above or below the dispatch target in the rare event that actual system frequency remains outside the normal operating band over multiple dispatch intervals.

The paper indicates that a demand side participant FCAS provider will also be paid on enablement and then audited based on its deviation from its baseline. The baseline proposed is the normal trading interval baseline calculated in accordance with the Baseline Calculation Methodology. FCAS events tend to be random and generally do not neatly align with the start and finish of trading intervals, and thus the proposed trading interval baseline calculation is inappropriate. It is also rare that a FCAS event would last for an entire trading interval. It is possible that a demand side FCAS provider has actual output less than its baseline over the trading interval but has actually contributed nothing to the frequency recovery following an FCAS event as its output reduction may have occurred following the recovery of system frequency. This could be particularly the case when the FCAS event also results in an energy price event at the succeeding dispatch intervals. Data arrangements of sufficient accuracy would need to be implemented with any demand response FCAS provider to prevent this inaccurate calculation of FCAS response. The currently proposed BCM would be insufficient for use in calculating FCAS response.

Also, in calculating any demand side FCAS response AEMO would also need to discount the response by the normal load relief function currently allowed for in the Market Ancillary Services Specification.

The paper indicates that any FCAS service provider would need to fully comply with the Market Ancillary Services Specification including all current technical requirements. We strongly support this as a provision of any new rule.

11.2 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?

For the reasons indicated in the answer to question 11.1, it is possible that allowing entry of greater demand response in the provision of FCAS contingency services may result in a reduction in the quality of FCAS contingency services unless the demand side provider has the ability to provide suitable and accurate data to allow reliable audit of actual FCAS response. The currently proposed method of a trading interval historical baseline will not achieve this. Allowing insufficiently audited demand side participation could also result in displacement or withdrawal by current higher quality service providers, leading to even lower quality frequency outcomes. A participant operating multiple generating units could choose to operate fewer units if there is a reduced requirement for FCAS from that supplier.

Also, the slower responsiveness and lower reliability of demand response makes any additional FCAS benefits unlikely. The majority of the FCAS services are provided in *real time* by plant with specific in-built designed capability to maintain the electrical power system within a set of closely defined parameters. Demand response may be useful to supplement one, or at the most two, of these services due to its inability to react in *real time* to changes within the power system.

11.3 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?

We support the Commission's view that the most likely area of entry will be the FCAS contingency raise services. It is also probable that demand response may be limited to the Delayed (five minute) service due to the time period required for demand response to respond to a FCAS event. Centrally controlled switchable battery banks, of sufficient size, may in the future be able to supply FCAS regulating services.

The overall ancillary services unbundling (ASU) proposal

12.1 In stakeholders' view, how would the ASU proposal impact on the cost of balancing supply and demand in the NEM?

The ASU may result in a slight reduction in the cost of FCAS contingency raise services. However, it should be noted that FCAS contingency raise services are fully funded by generators, so reductions in the costs of supply of this service may not flow through to customers. There may be benefits to customers in the energy market as megawatt increments on the margin currently reserved on generators by the National Energy Marker Dispatch Engine (NEMDE) to supply FCAS contingency raise services may now be available for dispatch into the Energy market leading to reduced Energy price outcomes. However, any price benefit will depend on the bid price of these marginal energy blocks.

12.2 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?

It is uncertain that the ASU would result in any improvement for AEMO to manage system security and reliability. To provide tangible benefits with regard to system security, the physical location on the network of these load blocks would need to be registered with AEMO and these load blocks would need to be available for automatic dispatch by the NEMDE via constraint equations, as opposed to the current proposal for dispatch by a DRA only. There may be limited benefits if these demand blocks are subject to the Directions provisions of Clause 4.8.9 of the NER, dependent on time requirements to facilitate any load reduction. It also needs to be recognised that commercial terms for dispatch of these load blocks may result in their dispatch limits being exhausted within a designated time period and may render them unavailable for dispatch at subsequent dispatch intervals which may align with increased network congestion and possibly higher RRP outcomes.

12.3 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?

In some situations, the lack of central control of the dispatch of a demand response load could lead to increased congestion on sections of the network following initiation of a demand response interval.

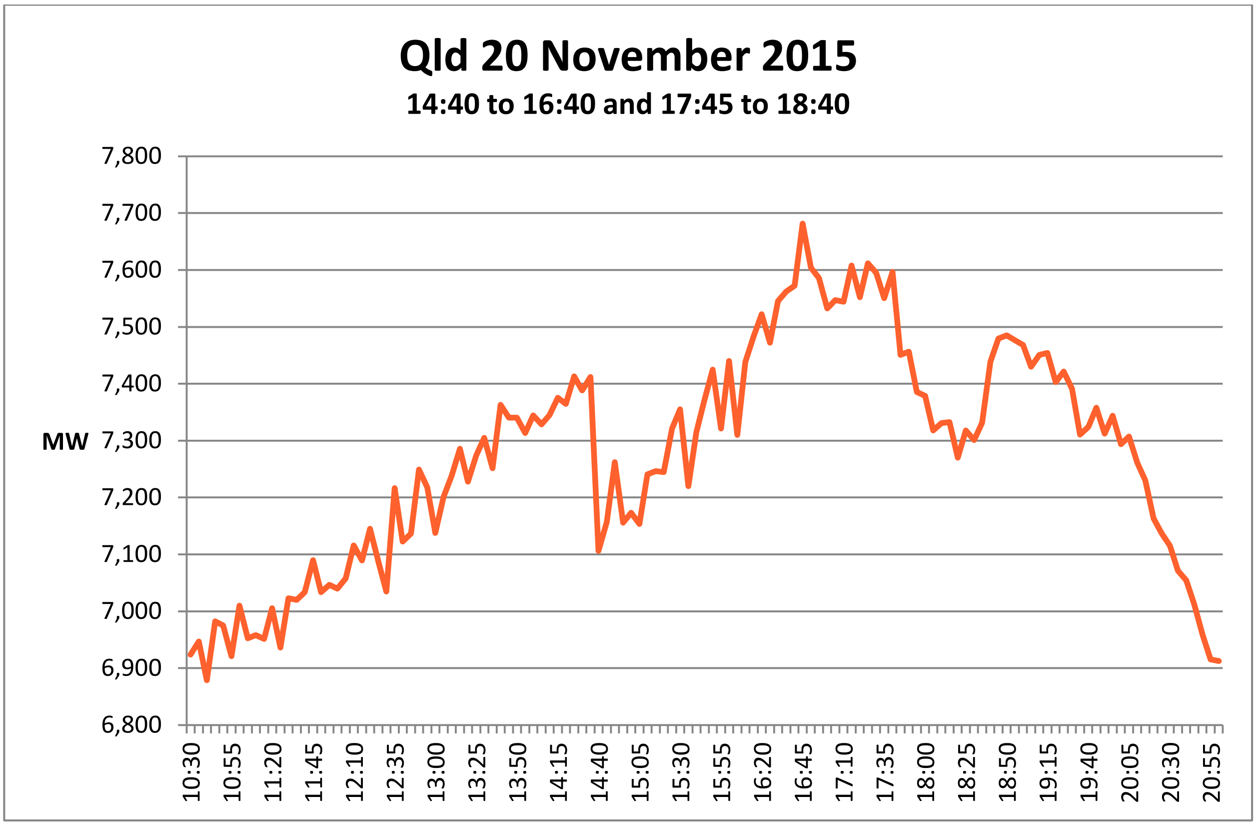
Interactions with the DRM

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

Similar to the current NEMDE calculation for supply of energy and FCAS by current providers (where providers that are ramping for supply of energy are excluded from the provision of FCAS) when a DRA has declared a demand response interval, then that the demand response load is no longer able to be dispatched for FCAS contingency services. This is because it has already been dispatched for demand response and should be automatically excluded from FCAS contingency services in the NEMDE calculations.

APPENDIX A: LOAD CURTAILMENT EXAMPLES

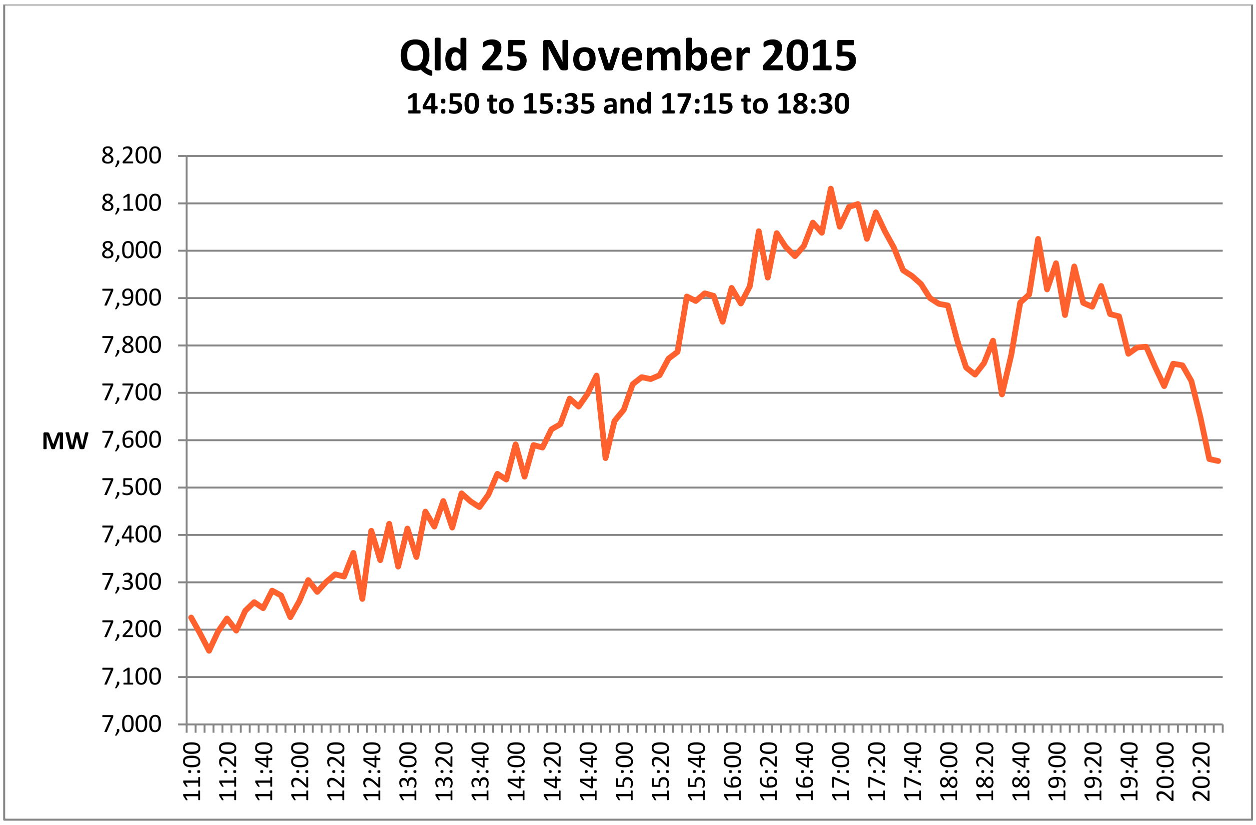
Queensland 20 November 2015



Notes:

- Pre-dispatch forecasts for both NSW and Qld were indicating very high prices from the 15:00 trading interval through to the 18:00 trading interval.
- Qld and NSW demand had been steadily increasing post the normal morning ramp up period.
- At the 14:40 dispatch interval a demand response of approx. 300 MW was observed in the Qld region, this demand response was maintained until approximately 16:05 when AEMO data indicates a restoration of the interrupted load had commenced.
- From 17:40 that evening, rather than following a normal steady decline in demand a further demand response of approx. 140 MW was observed until approx. 18:35 when AEMO data indicates a restoration of the interrupted load had commenced.

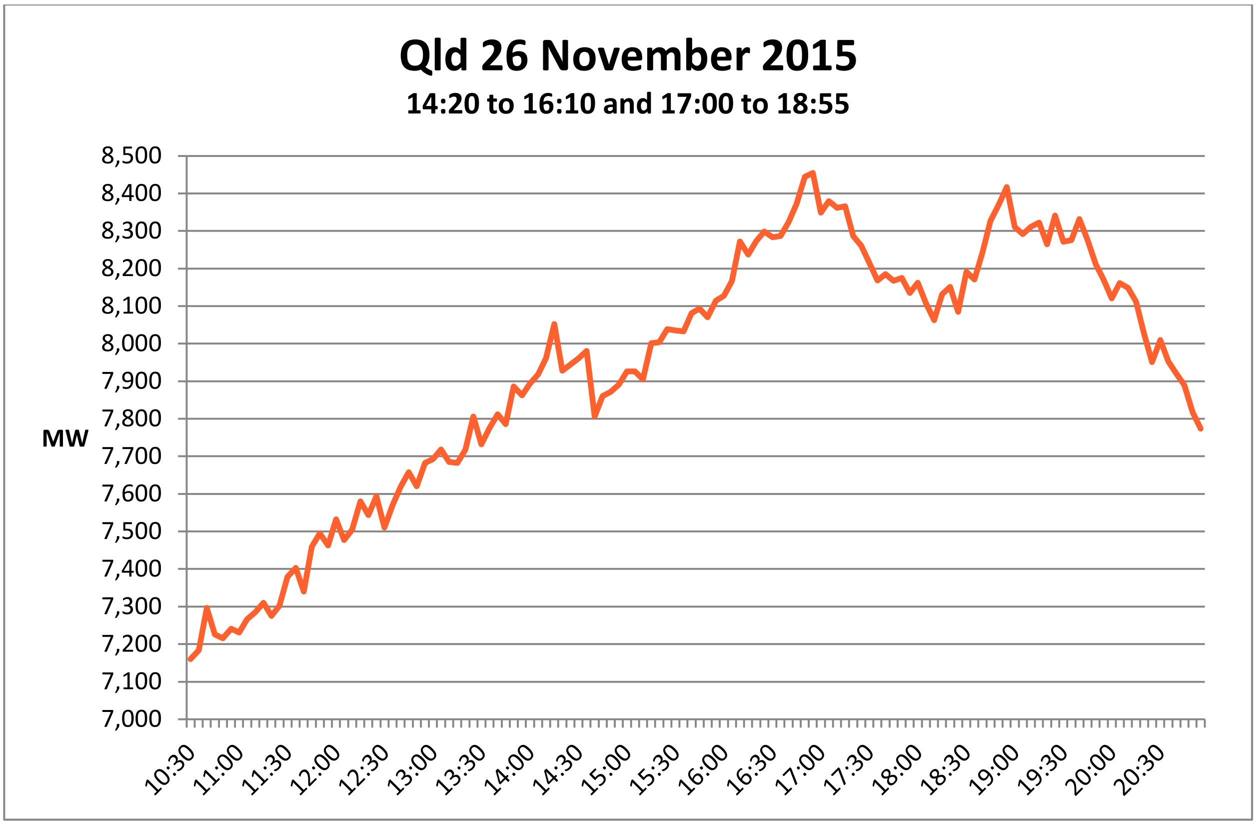
Queensland 25 November 2015



Notes:

- Pre-dispatch forecasts for both Qld, and to a lesser extent NSW, were indicating very high prices from the 15:00 trading interval through to the 17:00 trading interval.
- Qld and NSW demand had been steadily increasing post the normal morning ramp up period.
- At the 14:50 dispatch interval a demand response of approx. 200 MW was observed in the Qld region, this demand response was maintained until approx. 15:25 when AEMO data indicates a restoration of the interrupted load had commenced.
- From 17:20 that evening, rather than following a normal steady decline in demand a further demand response of approx. 140 MW was observed until approx. 18:25 when AEMO data indicates a restoration of the interrupted load had commenced.

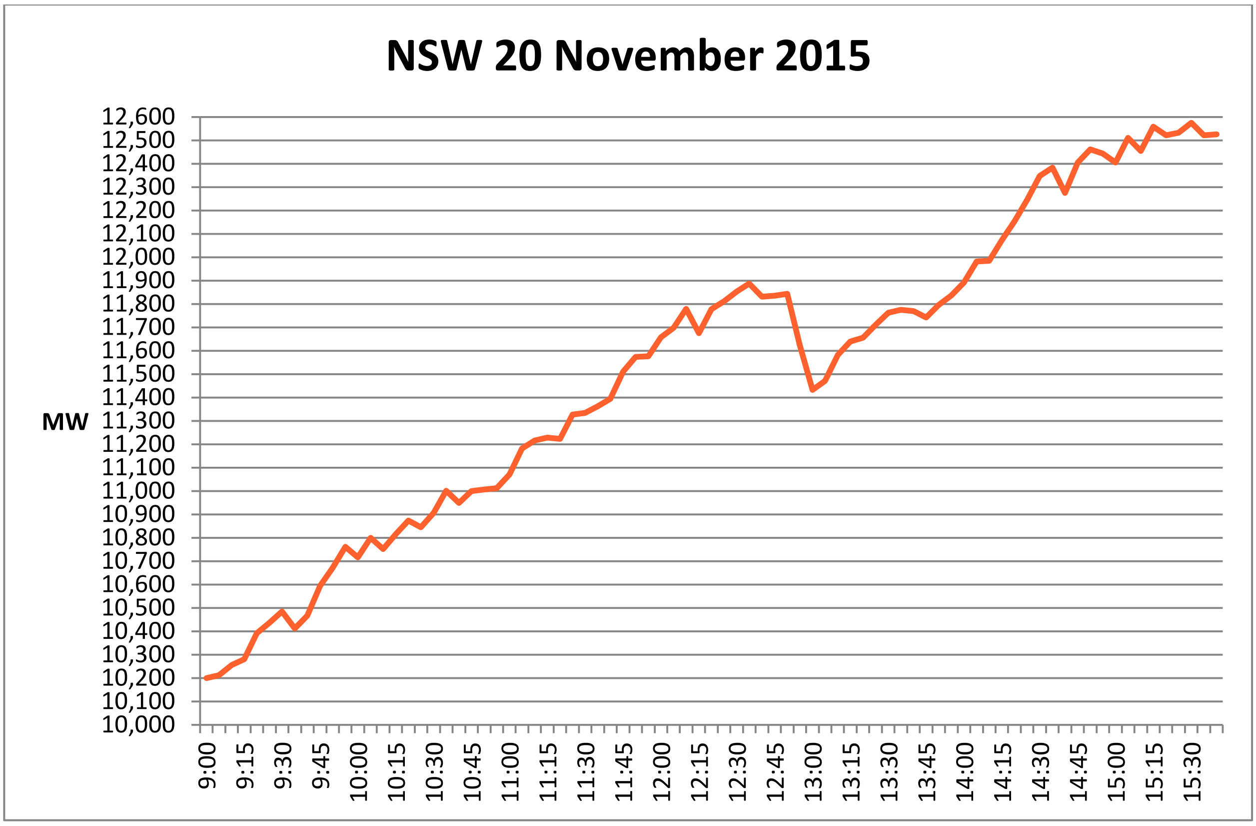
Queensland 26 November 2015



Notes:

- Pre-dispatch forecasts for both NSW and Qld were indicating very high prices from the 14:30 trading interval through to the 16:30 trading interval.
- Qld and NSW demand had been steadily increasing post the normal morning ramp up period.
- At the 14:50 dispatch interval a demand response of approx. 200 MW was observed in the Qld region, this demand response was maintained until approx. 15:55 when AEMO data indicates a restoration of the interrupted load had commenced.
- From 17:00 that evening, rather than following a normal steady decline in demand a further demand response of approx. 140 MW was observed until approx. 18:30 when AEMO data indicates a restoration of the interrupted load had commenced.

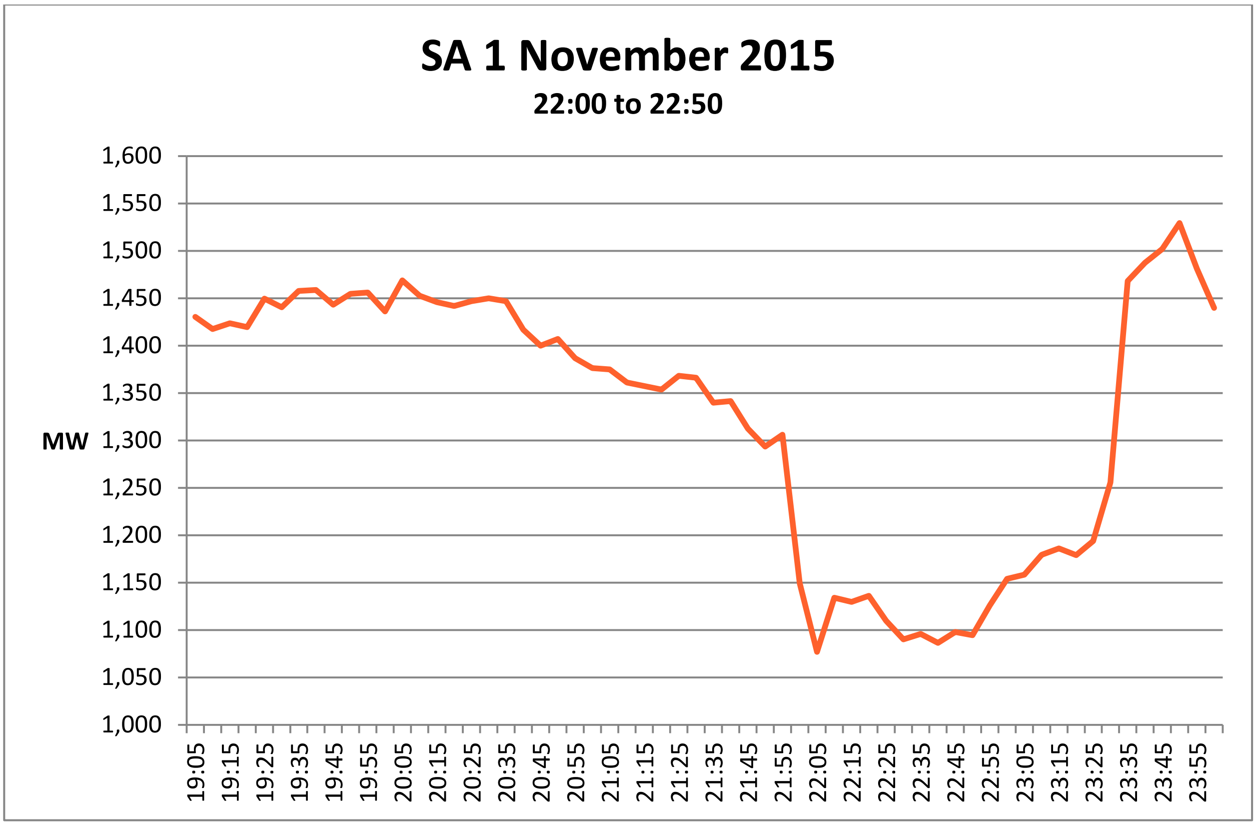
New South Wales 20 November 2015



Notes:

- Pre-dispatch forecasts for both NSW and Qld were indicating very high prices from the 13:30 trading interval through to the 16:30 trading interval.
- NSW was forecast to experience its first demand outcome in excess of 12,500 MW since January 2013.
- A number of generating units in NSW were unavailable due to planned and unplanned outages.
- One of the four major line flow paths from the Snowy sub-region to Central NSW was out of service limiting energy flow from Victoria via the interconnector as well as Uranquinty, Shoalhaven and the Snowy generators.
- Qld and NSW demand had been steadily increasing post the normal morning ramp up period
- At the 12:55 dispatch interval a demand response of approx. 500 MW was observed in the NSW region, this demand response was maintained until approx. 13:50 when AEMO data indicates a restoration of the interrupted load had partially commenced with all load restored around 14:30.

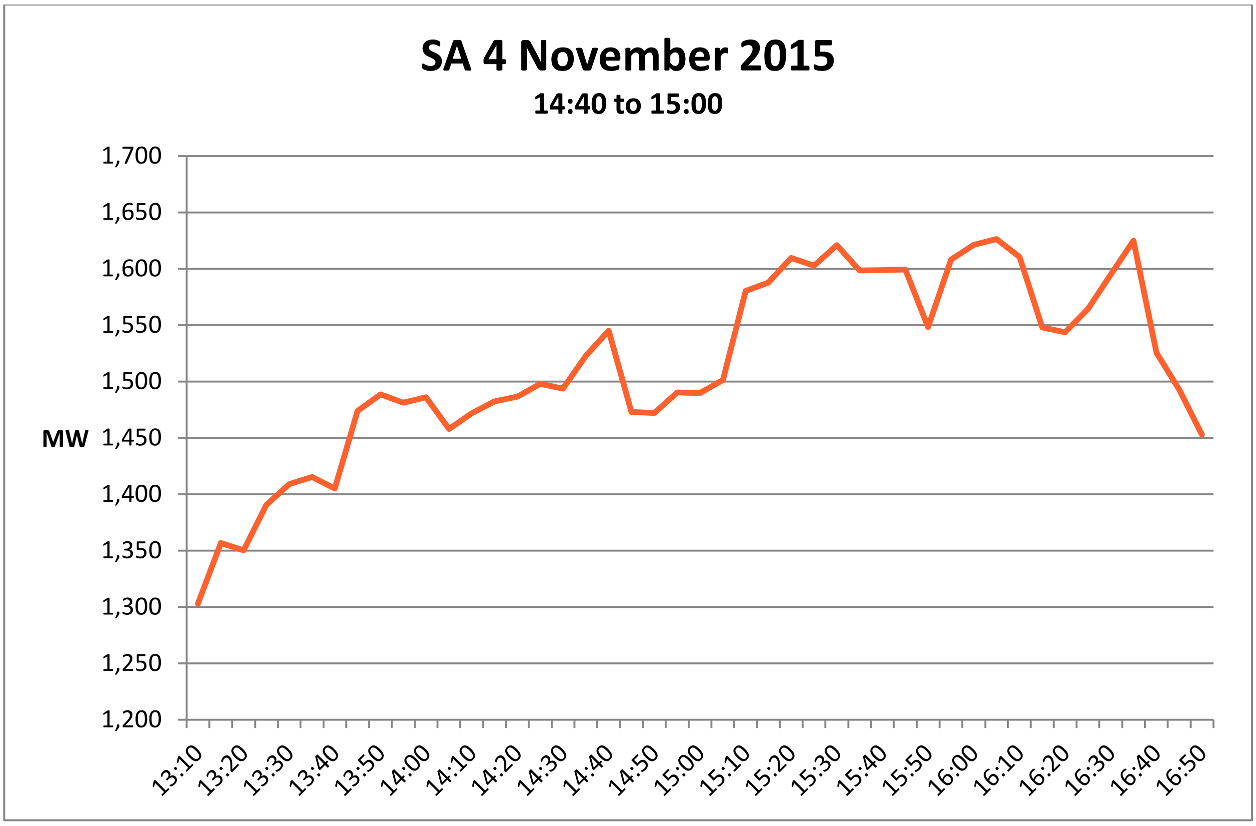
South Australia 1 November 2015



Notes:

- SA experienced a RRP of $2,174 at the 22:00 dispatch interval.
- In response to this event, SA demand reduced by 230 MW.
- With the subsequent drop in RRP over the 22:05 and 22:10 dispatch intervals, SA demand recovered approx. 60 MW, however, a further price event at 22:20 of $10,759 saw this 60 MW again removed.
- Load restoration commenced from 22:55 with load restoration completed approx. 23:30.

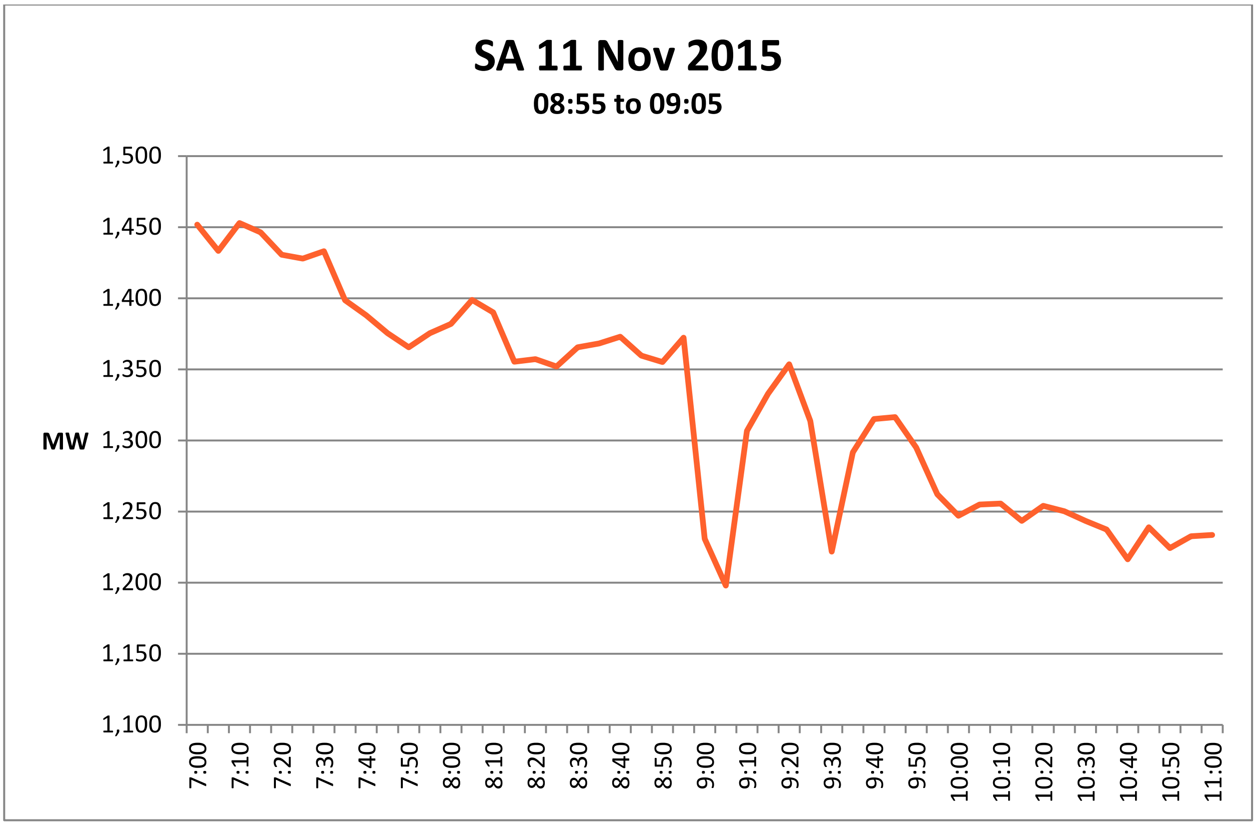
South Australia 4 November 2015



Notes:

- SA experienced a RRP of $13,331 at the 14:40 dispatch interval.
- In response to this event SA demand reduced by 90-100 MW.
- Load restoration commenced from 15:05 with load restoration completed approx. 15:10.

South Australia 11 November 2015

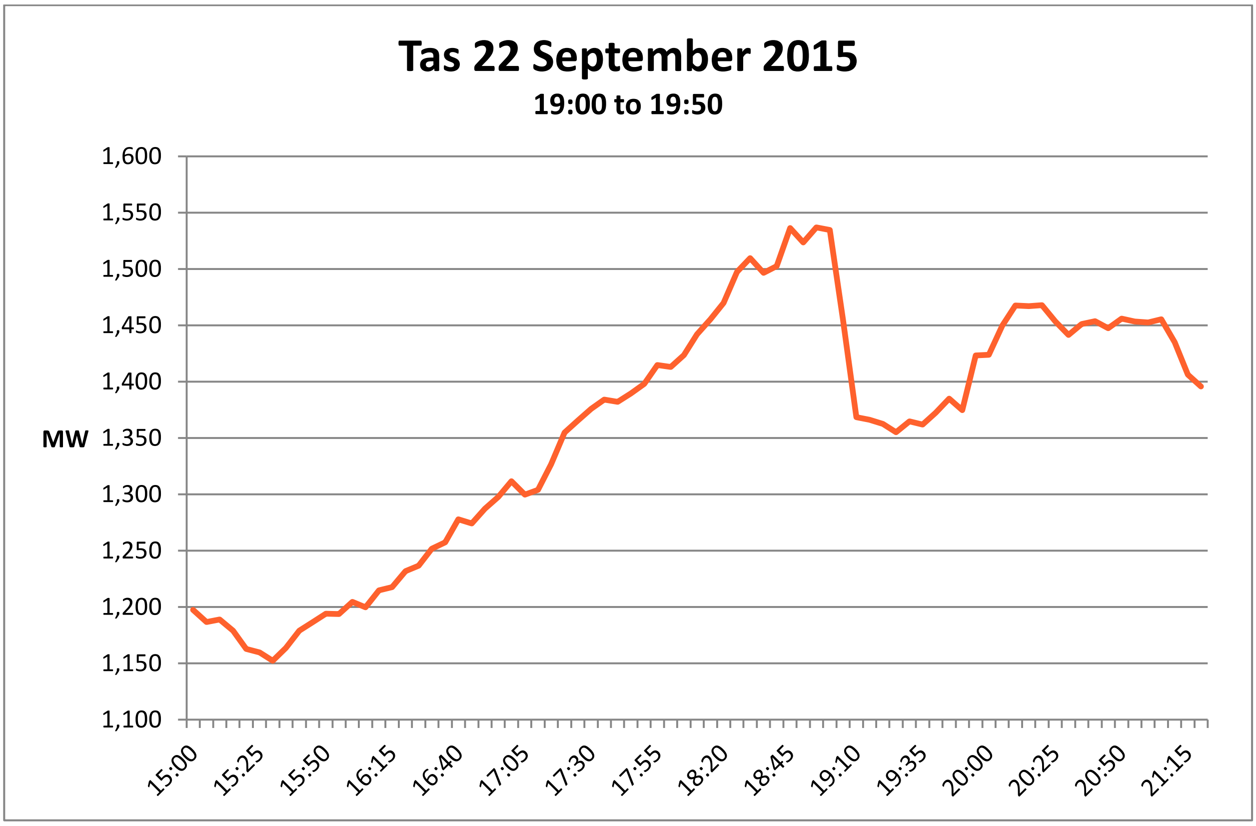


Notes:

- The supply demand balance in SA was tight due to network outages impacting the capability of both Heywood and Murray link to export from Vic to SA.
- Northern 2 was unavailable for service due to plant issues.
- Total SA wind output was very low at less than 200 MW.
- SA experienced a RRP of $13,482 at the 13:30 dispatch interval.
- In response to this event SA demand reduced by 140-150 MW.
- With the start of a new trading interval, load restoration commenced from 13:35 with load restoration completed approx. 13:40.
- However, a further price event to $1,037 at the 13:40 dispatch interval saw this load once again withdrawn at the 13:45 DI.
- With the start of a new trading interval load restoration load restoration occurred for the 14:05 with the price again increasing to $590. At the next dispatch interval demand response was once again observed.
- A further 10 dispatch interval (5 minute) price events between $1,500 to $288 continued following demand restoration until 16:45 that day, with a period of demand restoration often followed by demand response to increased price outcomes.

- From the 17:05 Dispatch Interval with Murraylink restored to normal operation price volatility decreased and SA demand outcomes stabilised to a more normal pattern

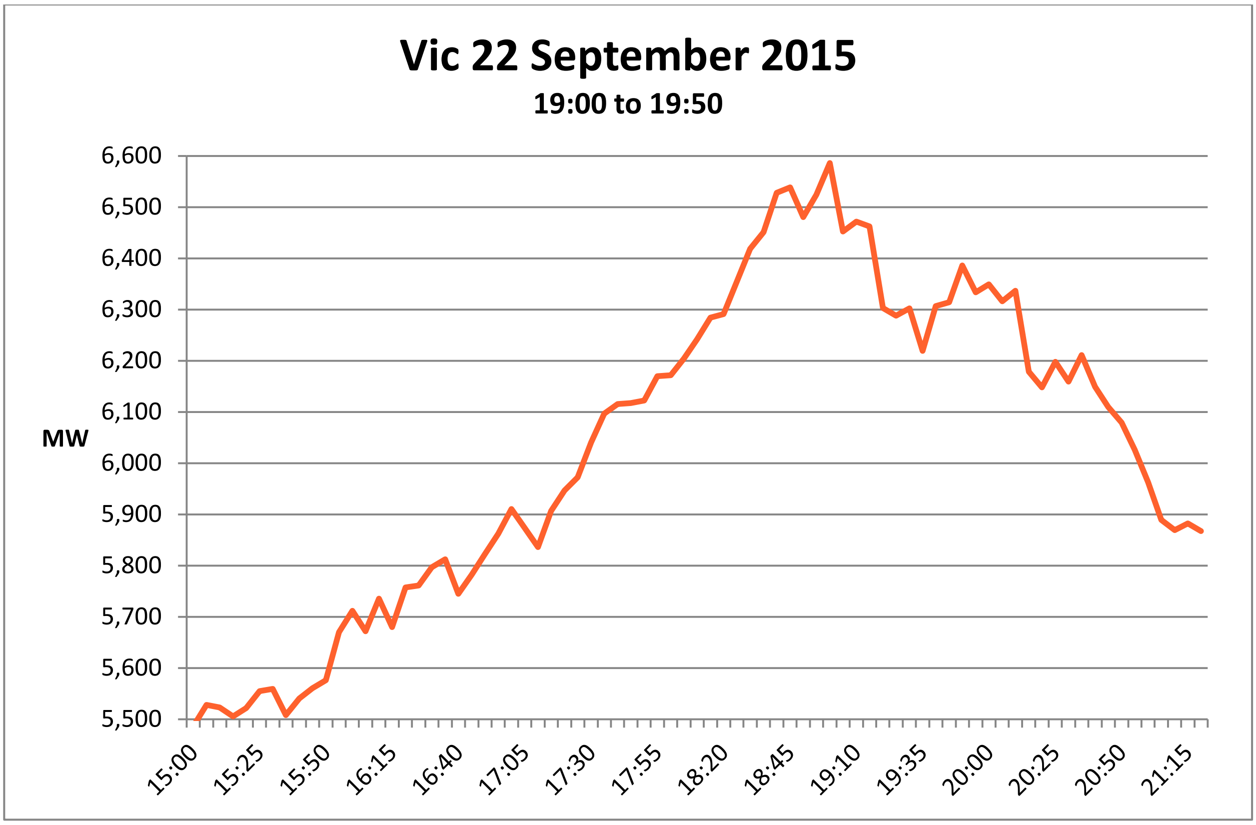
Tasmania 22 September 2015



Notes:

- At the 19:00 dispatch interval Tasmania experienced a $11,656 price outcome.
- In response to this event Tasmanian demand decreased by approx. 180 MW.
- Load restoration commenced at approx. 19:25 and load was restored by 20:10.

Victoria 22 September 2015



Notes:

- At the 19:00 dispatch interval Victoria experienced a $12,438 price outcome.
- In response to this event Victorian demand decreased by approx. 180 MW.
- Load restoration commenced at approx. 19:40 and load was restored by 19:55.