RELIABILITY FRAMEWORKS REVIEW

Response to interim report

January 2018

1. Market based reliability framework

The NEM operates under a Reliability Standard which aims to balance the cost of providing additional reliability with the value of additional reliability (or the cost of loss of supply). The standard is set by the Reliability Panel which is a specialist body within the Australian Energy Market Commission (AEMC) and comprises industry and consumer representatives.

> *"The standard in fact specifies the maximum expected unserved energy or the amount of electricity demanded by customers which is at risk of not being supplied. It is currently set at 0.002 per cent of each region's annual energy consumption in a financial year.*
>
> *It is important to note that by "expected" we mean a forward looking concept applied to each year as a discrete interval. As outlined previously the critical part of the definition of the reliability standard is that it is an ex-ante planning standard—a key input to relevant national electricity market planning and operational processes. It is not an operational standard, which the system either "succeeds" or "fails" in meeting in any given period."* [1]

In November 2017 the Reliability Panel released a draft report indicating its intention to retain the current Reliability Standard for the 2020 to 2024 period, a position which was supported unanimously in written responses. We believe that the Reliability Standard is relatively well understood, particularly the fact that it does not require continuous supply at any cost in all circumstances.

In addition to its use as a planning standard, the Reliability Standard guides various decisions made by AEMO in its role as system operator. AEMO takes every opportunity to manage shortfalls in the operational timeframe regardless of whether the Reliability Standard is or is likely to be met in a given financial year. Unlike the planning standard, this operational regime appears poorly defined and supported in the NEL and NER, particularly as many of the actions taken by AEMO can incur costs in excess of the Reliability Settings (Market Price Cap, Cumulative Price Threshold and Administered Price Cap). As identified in AEMO's submission to the issues paper, there are separate but overlapping powers (RERT and Directions) which can be invoked in the operational timeframe with different outcomes for the market and participants and clarification of this area of reliability is likely to be of long term benefit to the market and consumers.

As noted in the Reliability Panel Draft report and responses, and again in the AEMC's Interim Report, the Energy Security Board is also developing a proposal for the National Energy Guarantee (NEG). While further detail and consultation is expected in February 2018 it appears likely that the NEG will include a Retailer Reliability Obligation based around the Reliability Standard. It is unclear whether the obligation is intended to apply to the planning standard or AEMOs operational measures. Any consideration of market design going forward will need to be consistent with, or at least account for the probability of the yet-to-be-designed NEG.

The importance of reserves

In the NEM, reliability is typically supported by scheduled and semi-scheduled resources (currently only generation and some pumping load is scheduled) being available regardless of whether it is dispatched and regardless of what price it is offered at. Indeed reliability typically requires an amount of scheduled resources to be available but un-dispatched, referred to as reserves.

As these reserves are not directly compensated under NEM design[2] the revenue to support their existence must arise through other channels, typically portfolio benefits[3], contract premiums or both.

Importantly for this review only resources which are visible to and controllable by the market operator are accounted for in determining reserves and consequently reliability. Out of market resources such as demand response, non-scheduled generation, RERT contracts and scheduled generation which is only available in response to a direction[4] do not support reliability without intervention. Stanwell note that AEMO have indicated that if a strategic reserve were to replace the RERT

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[1] Reliability Panel, *Reliability standard and reliability settings review 2018,* Issues paper, 6 June 2017. Page 12

[2] although in some circumstances they may be enabled and compensated for contingency raise frequency control services

[3] Including generators offering generation at one site above its marginal cost in order to recover sufficient revenue to offset the cost of the entire portfolio. This is additional to the "missing money" issue typically considered in relation to wholesale market pricing.

[4] Including but not limited to the South Australian Government owned diesel generation installed during 2017

"Operation of strategic reserves would also be considered unserved energy for the purposes of reporting against the relevant reliability standard."

Stanwell considers that this review should prioritise making resources available in-market where possible in preference to out-of-market participation. This may require either alteration of existing market systems and processes or new market design elements in order to account for the capabilities of these resources.

The importance of contracting

The AEMC makes a number of references in the interim report to contracts supporting reliability. Stanwell agrees that contracting provides indirect support for reliability by informing investment and operational decisions, but caution that this does not mean that contracting provides reliability as implied in the AEMO submission.

Contracting is neither required nor sufficient for the reliable supply of electricity to consumers because it is a financial derivative, not a supply agreement. The seller of a contract may or may not be a generator and the buyer may or may not be a Market Customer. A contract between Westpac and Macquarie Bank is identical[5] to a contract between Stanwell and AGL, and neither will directly affect the ability of the system to provide electrons at any point in time to any point in the network. A customer who is fully hedged will be subject to the same system security and reliability risks as a customer who is fully exposed to spot prices.

That does not mean that contracts do not support reliability. The primary functions of contracts are to keep generation financially viable (smooth, sufficient, predictable cashflow) until it is valued by the system and to provide price stability to retailers that can be passed on to consumers at low risk. Generators who have sold contracts are more likely to be available at a lower price than generators who have not, all else being equal.

Further, Stanwell notes that recommendation 3.2 of the Finkel review included a proposal for large generators to provide a minimum three years' notice prior to closure and expects that, if progressed, such a measure would largely supersede the reliability benefits currently provided by contracts in relation to these generators. While COAG did not explicitly endorse this recommendation (which also contained the proposed Clean Energy Target), Stanwell understands that the ESB intends to lodge a rule change request in relation to this requirement imminently.

It is within this framework that Stanwell provides this response.

- The Reliability Standard is an accepted planning standard, and supported by the Reliability Settings is designed to provide a high level of reliability within a defined price envelope;
- In the operational timeframe AEMO attempts to minimise or eliminate unserved energy, including by taking actions which may incur a higher cost that envisioned under the Reliability Settings;
- Reserves are necessary but currently un-valued resources;
- Contracting is important but not directly linked to reliability; and
- There are a number of concurrent processes which may impact on the reliability frameworks which are unable to be fully integrated into this response at the time of writing.

Stanwell also reiterates its position from recent rule change processes that changes to market design will only be in the long term interest of consumers if the benefits exceed the cost of change, not simply because there may be theoretical benefits from a different approach.

Stanwell welcomes the opportunity to discuss further this submission, please contact Jennifer Tarr on (07) 3228 4546 or Jennifer.Tarr@stanwell.com

[5] Subject to terms and conditions such as credit support.

2. Forecasting and information provision

Stanwell endorses the AEMC's view that forecasting affects all components of the NEM and that in any electricity system it is unavoidable that decisions need to be made for the future based on forecasts made now.[6] The quality of the decisions being made cannot be better than the information the decisions are being made on, whether it is investment decisions based on supply/demand forecasts or supply/demand forecast based on the information provided to the forecaster.

In essence, the quality of a forecast will depend on two issues – the quality of the inputs and the quality of the analysis of those inputs.

Quality of analysis

A recent report from the University of Wollongong[7] raises significant issues with regards to whether the current analysis model remains fit for purpose when forecasting demand over short periods (particularly within the pre-dispatch window). Findings include:

- *"The report provides strong evidence that the current AEMO neural network model is not suited to accurately perform dispatch demand forecast."*
- *"It is demonstrated and explained that the current model cannot deal with abnormal conditions that arise out of volatility, spikes, shocks, price responses, and any other situation which require the modelling of context for accurate predictions."*
- *"The report finds that the type of neural network used by AEMO is a first generation neural network that is over 20 years old."*
- *"Much more appropriate methods have been developed in the years since the adoption of AEMO's current neural network model."*

While the upgrade or replacement of such a fundamental aspect of the market would be costly and time consuming, Stanwell considers that high level cost-benefit analysis should form part of the reliability frameworks review. This is particularly important given that the market evolutions described in the Interim Report are essentially "*…abnormal conditions that arise out of volatility, spikes, shocks, price responses, and any other situation which require the modelling of context for accurate predictions.*"

In addition, AEMO's dispatch demand forecast is a key determinate of dispatch outcomes.

Dispatch forecasts

Systemic inaccuracy in AEMO's dispatch forecast leads to inefficient generator dispatch, risk of reliability problems and increased frequency control ancillary services costs. AEMO's dispatch forecast is a key input into AEMO's dispatch engine and is used to determine to what level scheduled generators must be targeted.

Analysing NEM frequency outcomes is one method to test the effectiveness of AEMO's dispatch forecast. The better the dispatch forecast the fewer the deviations from 50Hz. The heat map shown in Figure 1 **Error! Reference source not found.**below shows the average mainland frequency per five-minute interval for 2016. Patterns in the data imply systemic forecast errors resulting in over or under frequency events. For example, the horizontal lines close to midnight may relate to hot water switching and the evening red "unhappy mouth" that begins in April and ends in September may relate to issues associated with forecasting light switching, roll off of solar or the synchronisation of fast start generators to meet evening peak demand.

[6] Interim report, Pages 55, 56

[7] Executive Summary, Ibid

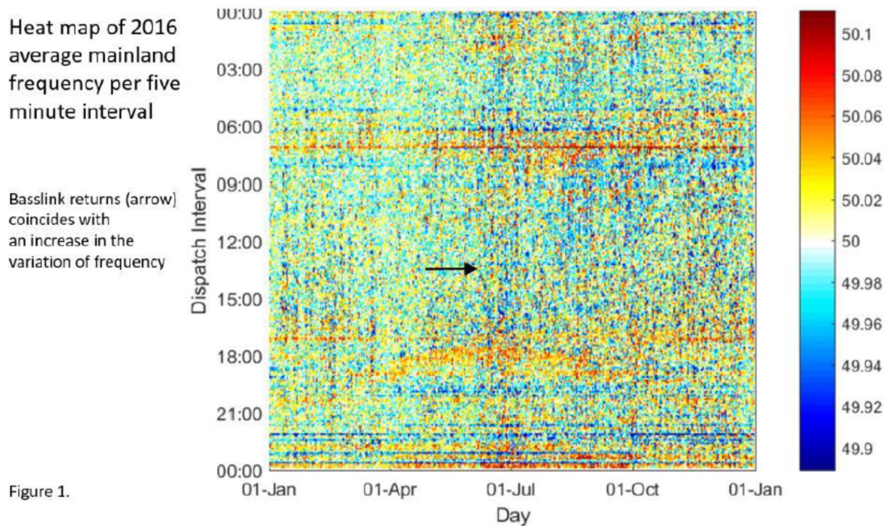

Figure 1: Average frequency 2016[8]

Patterns in the data imply that dispatch forecasting can be improved. This is consistent with the recent findings of the University of Wollongong[9]. pdView suggests that the addition of an intelligent learning algorithm which contains a feedback loop would eliminate these systemic errors and probably fix other systemic errors that are not observed by the eye.

Stanwell considers that an urgent review of AEMO's dispatch forecast is required. It is likely that an upgrade to AEMO's dispatch forecast, in conjunction with greater information on the intentions of non-scheduled resources, will achieve improved reliability and frequency outcomes at a cheaper cost to consumers compared to major changes to the reliability or frequency frameworks.

Quality of inputs

The potential for improvements to be gained from an improved analysis engine should not preclude consideration of how to improve the information being provided to the forecasting process, and a number of potential avenues are identified in the Interim report.

The Interim Report states *"… for scheduled generation and loads in the NEM, participants provide their own inputs into AEMO's central dispatch system based on their expectations of market conditions, while AEMO forecasts the output of semi-scheduled and non-scheduled generation as well as non-scheduled loads….. This should result in efficient outcomes since it leaves forecasting demand and supply, and decisions regarding unit commitment, in the hands of market participants - who have a strong financial incentive to act efficiently and bear the risk of not doing so (rather than consumers)."*[10]

and

"…the Commission also recognised the technological change that is currently occurring, which is likely to result in increased amounts of small generation and more responsive loads. In order to maintain a transparent market with accurate information for participants, the requirements to participate in central dispatch may also need to change."[11]

Stanwell considers that recognising and responding to this change will be a critical pre-condition to retaining an efficient and functioning market going forward. Currently, AEMO does not have transparency of the intentions of price responsive unscheduled[12] market participants who are becoming a larger share of the market (as discussed above). In order to deliver security, reliability and efficient pricing AEMO must have visibility of any party that is actively participating in the wholesale market, including their intentions in both the planning and operational timeframes. Compared to the past where AEMO controlled a handful of large generators against a predictable demand, AEMO now has significantly less control.

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[8] Figure 1, Regulation FCAS Report 1, pdView, 2017
[9] University of Wollongong, Evaluation of neural network models for AEMO's five minute electricity forecasting, 13th December 2016

[10] Interim report, Page 72
[11] Interim report, Page 68
[12] Non-scheduled and registration exempt

Potential improvements to inputs

1. Incorporating new technologies

AEMO have already released *Interim arrangements for utility scale battery technology* which aims to address visibility and control issues by requiring batteries in excess of 5MW to register as both a scheduled generator and scheduled load. While interim arrangements may be a necessary transitional step they provide little certainty to participants or policymakers.

The interim guidelines are informative for this review both because they represent AEMO exercising it's existing powers to require participation in central dispatch and because they include a requirement to provide AEMO real time information which is not able to be represented in current market structures. The provision of real time charge status is significantly more relevant for such energy limited resources than the daily energy limit or half hourly availability offers currently allowed for in the prescriptive bid structures scheduled participants are obliged to comply with.

While the AEMC did not make the requested rule requiring smaller generators and loads to participate in central dispatch[13], AEMO are requiring this outcome from specific participant types under the interim arrangements. This scheduling improves the visibility of the system for AEMO and increase the ability for these batteries to inform forecasts and ultimately support reliability.

2. Greater input into AEMO forecasts from *semi-scheduled generators*

The AEMC suggests that semi-scheduled generators could be allowed to offer their availability on a trial basis[14]. Stanwell supports this initiative and expects it will result in more efficient outcomes. AEMO's wind and large scale solar forecasts are directly linked to wind and solar participants' financial returns through AEMO's causer pays procedure. As a result, participants have historically been very engaged in improving these forecasts and are likely to support this initiative.

[13] ERC0203
[14] Interim report, Page 74

3. Greater input to AEMO forecasts from *Market Customers*

The AEMC has suggested that retailers could provide AEMO with a forecast of their customer load for dispatch by AEMO[15]. This proposal may be worth further investigation and is similar to the provision of semi-scheduled availability offers above as both processes would increase the provision of information by participants and reduce reliance on AEMOs internal forecasts.

We note however that there are issues to be carefully considered, not least of which is the scope of what is being proposed. For example would the forecasts be regional, by connection point or somewhere in between? Would they be assumed to be price sensitive or inelastic, and how would demand response/participation be incorporated (see next section). Would the provision be voluntary or mandatory, and would it apply to Market Customers or retailers? To the extent that retailers were to provide forecasts what would be the compliance burden associated with the accuracy of those forecasts – would they be scheduled or non-scheduled?

The provision of forecasts by commercial entities also introduces the potential for conflicting objectives. For example, a retailer may have an incentive to under-forecast and set the energy price low while incurring the cost of balancing services. The penalty for under-forecasting (causer-pays or otherwise) is unlikely to exceed the gains obtained by reducing the wholesale energy price by an intentional under-forecast. Unlike market scheduled generators Stanwell expects that most load would not be subject to binding dispatch targets or AGC-equivalent control.

Forecasts of demand response without scheduling-like obligations may also be self defeating - particularly as volume grows. For example, AEMO assumes a demand response and clears a low energy price as a result the demand response may not eventuate because the price is low. The University of Wollongong report refers to this as "a feedback loop which may not converge"[16].

[15] Interim Report, Page 76
[16] University of Wollongong, Evaluation of neural network models for AEMO's five minute electricity forecasting, 13th December 2016, page 18.

3. Wholesale Demand Response

Demand side participation versus demand side response

It is crucial for the AEMC to consider setting regulatory frameworks that encourage resources to *participate* in the market rather than *respond* to it or operate outside the market.

Demand side *participation* is distinct and far more beneficial than demand side *response.* Demand side participation is when the intentions and price sensitivities of demand are understood by AEMO and can be properly incorporated into forecasts, dispatch and frequency requirements. Demand side response on the other hand occurs when sophisticated loads (individually or in aggregate) react in an un-forecast manner, contributing to price volatility and frequency deviations. “Demand response can be used to reduce exposure to high wholesale prices”[17] for individual customers but demand side participation means demand and supply are correctly balanced resulting in lower wholesale prices and reduced volatility for all customers.

Through the AEMC’s Frequency Control Frameworks Review the AEMC expressed concern regarding the future impact on dispatch and frequency of home energy management systems and distributed networks of batteries acting in unison. Stanwell shares these concerns and adds unforeseen demand response from large customers and resources acting outside the market[18].

Last summer, Stanwell observed the un-forecast actions of several sophisticated large customers directly affecting market operation. We observed times when in excess of 300MW of un-forecast demand reduction occurred within a dispatch interval. Because it is un-forecast and uncontrolled by the market operator, these resources do not contribute meaningfully to the calculations of reserve adequacy but can affect system operation.

Providing AEMO with sufficient visibility of demand side resources in order to incorporate their effects into dispatch would significantly decrease their adverse impacts on system operation and price volatility while retaining the benefits sought by the operators of those resources. Alternatively, AEMO must increase their procurement of control services to provide an appropriate buffer to account for these un-forecast actions.

[17] Interim report, Page 109

[18] For example through RERT/Strategic reserves, network support and directions processes or being non-scheduled or non-registered.

Demand side contribution to reliability

The distinction between demand side response and participation is likely to be important when considering the contribution that these resources can make to reliability in both the planning and operational timeframes. Non-visible, non-controllable resources are less able to be incorporated into reserve forecasts as there is less information about their characteristics and less certainty about their actions at times of interest.

The AEMC’s discussion on demand response also assumes that demand response is needed for reliability purposes when prices are high. Stanwell cautions that this relationship is stronger in theory than in practice, and has provided the AEMC with examples of non scheduled price sensitive resources increasing their consumption at times of peak demand, having earlier responded to high prices.

Network demand response

Stanwell supports investigation into whether demand response currently procured by network businesses is able to be provided to AEMO for use in dispatch without undermining its value to the network. This would lead to lower costs to consumers compared to the current situation where some networks are paid to provide demand response through the RERT process (SAPN - 276MW, Citipower/Powercor 60-100MW)[19] and other networks have large amounts of demand response completely outside the market (Energex 800MW)[20].

To support reliability, network demand response must be visible to and controlled by AEMO. It appears that network businesses can already respond to a signal to activate the demand response, so responding directly to AEMO signals is expected to be a relatively simple addition to these resources. However investigation may be required into how a bid by a network business will be incorporated into dispatch given the demand response is distributed throughout the network.

[19] AEMO, RERT Providers, December 2017

[20] AFR, Power mess still needs to be fixed, Page 1, 8 Jan 2018

Separating demand response from the retailer

The interim report discusses the possibility of a new participant category "demand response aggregator" who is responsible for recognising and utilising the demand response of retail customers. Stanwell does not support this initiative unless there is an identified framework to ensure these resources are visible to and controllable by the market operator and that the third party arrangements do not increase the cost or compliance burden of retailing.

There is evidence that demand response specialists (such as Flow Power[21]) are becoming retailers and that retailers are offering innovative demand response products (Origin, AGL, Powershop, Mojo). There are also co-operative arrangements between demand response specialists and retailers (Reposit and Diamond Energy) which allow each entity to pursue its focus. This implies that there is neither a barrier for demand response specialists to become retailers or a reluctance for retailers to offer demand response products. Creating a new participant category is therefore unnecessary and may even disadvantage the early movers. If there are inefficiently high barriers to becoming a retailer, then these are best addressed directly rather than by creating a new participant type.

Separating demand response from a retailer's customer load may also require additional metering and/or wiring at the customer premises adding to costs. This is because it is likely that a customer will not curtail all of their load in response to a signal, only certain processes.

The interim report mentions the high upfront costs of demand response. Stanwell agrees with the AEMC that this cost is "*best addressed by commercial entities who bear the risk of making an upfront investment to provide wholesale demand response, compared to other investments (e.g. generation) that could be made.*"[22]

Consistency with the National Energy Guarantee

For both demand side participation and demand side response, a key input into a customer's decision is the wholesale price. The more a customer is exposed to the wholesale price the more likely they will consider demand side participation or demand side response. However the more a customer is exposed to the wholesale price the less they are hedged and therefore the less generators are hedged. This appears to be against the design principles of the NEG where Market Customers – and by extension generators - are incentivised to be hedged which the ESB claims will reduce prices and price volatility.

Non-scheduled demand response also adds complications under the indicated NEG design. For example, to which level would a retailer hedge: the full retail load or the retail load with the demand response? Consideration should be given as to what the implications are for the retailer's obligations under the NEG if the expected (and contracted) demand response does not occur. Separating the demand response of a retail customer from the retailer and allocating this to a "demand response aggregator" would further complicate this process.

[21] https://flowpower.com.au/buy-smarter/
[22] Interim report, Page 119

4. Strategic Reserves

> "*Some form of a safety net, such as a limited and targeted ability for a system operator to pay a premium for capacity that is not otherwise being traded in the market, is appropriate in the event that the market is expected to fail to meet the reliability standard. Given the costs that can be associated with such safety nets, it is important to understand what the existing limitations are with the current safety net in the NEM, the Reliability and Emergency Reserve Trader (RERT), before a balanced solution to these limitations can be developed and assessed to make sure it is in the long-term interests of consumers.*"[23]

Stanwell agree that including a safety net mechanism within the reliability framework is appropriate as it is likely to be more efficient than the development of uncoordinated safety net schemes.

Stanwell also agree that any proposal to change the existing safety net design should explicitly identify what issue is trying to be solved and why the proposed solution is more proportionate and/or more effective than current arrangements in order to be in the long term interests of consumers.

Purpose of the scheme

The Reliability Standard is an accepted planning standard, and supported by the Reliability Settings is designed to provide a high level of reliability within a defined price envelope. The standards and settings allow for some unserved energy (USE) where it is considered that the cost of planning to provide that energy exceeds the value consumers would place on that energy.

Stanwell supports AEMO's submission where it identifies the lack of clarity in the existing rules as to whether safety net actions are intended to meet the reliability standard or maintain reliability.

Stanwell consider that the safety net is currently intended to minimise unserved energy (and manage system security) where it is able to do so, rather than to "meet" the Reliability Standard. This may include the market operator "paying a premium" as indicated in the quote above, however the framework should not support this premium causing the cost of supply to exceed the value to customers.

[23] Interim Report, page iii

It is also important to ensure that the design of the safety net does not compromise the incentives on investment and operation of resources such that resources are targeted into the safety net rather than the market. It is this area where Stanwell considers that the current arrangements are likely to be able to be improved, subject to consideration of the cost of making a change.

Existing safety net and incentives

The existing market design contains a number of "last resort" or safety net mechanisms, with the RERT and Clause 4.8.9 Directions/Instructions addressed in the interim report. Stanwell notes that the Rules also include provisions for Mandatory Restrictions[24], and that provisions around constraints and compensation are also relevant to incentives on investment and operation of resources.

In order to illustrate the incentives related to these schemes, consider the recently installed South Australian Government owned peaking plant, noting that it is an unusual investment. The generator is intended to support continuous supply to South Australian consumers while minimising distortion of investment and operational signals. In this respect it is different to a "normal" investment which would be expected to maximise profit through market participation.

- The plant is registered as a market scheduled generator, meaning it is technically capable of participating in central dispatch.
- The plant is not offered as being PASA Available, or available in daily bids[25]. This indicates that it is unable to be brought online given 24 hours notice[26] and prevents the generator from being included in reserve forecasts.
- Having been made otherwise unavailable, the generator is participating in AEMO's RERT program for summer. Stanwell is not aware of any

[24] Rule 3.12A of the NER

[25] The units are bid available during periods of testing.

[26] Rules Glossary "**PASA availability**: The *physical plant capability* (taking ambient weather conditions into account in the manner described in the procedure prepared under clause 3.7.2(g)) of a *scheduled generating unit, scheduled load* or *scheduled network service* available in a particular period, including any *physical plant capability* that can be made available during that period, on 24 hours' notice."

information indicating whether this participation is under contract or as a short-term panel member.

- If South Australia, or South Australia and Victoria, experience low reserve conditions AEMO may activate the generator under a RERT contract, triggering intervention pricing but paying the generator according to its RERT contract. Depending on the contract the generator may receive availability, pre-activation and activation payments.

Had the generator wished to support reliability without entering the RERT process, other options were available with different risk profiles.

- The generator could have offered itself PASA available[27] but unavailable in daily bids, signalling to AEMO that it may be available for direction under clause 4.8.9. The generator would still not be considered in relation to the calculation of lack of reserve levels in the operational timeframe. Notably, the Rules require AEMO to issue directions to generators *after* dispatching all available scheduled resources and activating RERT contracts, meaning that other RERT resources may be used rather than this generator, however the 34MW of demand response contracted for SA is dwarfed by the 170MW of generation[28]. If a direction was issued to the generator it would likely trigger intervention pricing and the generator would be able to claim compensation to recover the cost of responding to the direction. As no allowance for return on investment is included in the compensation arrangements, this approach is unlikely to be followed by a generation investment undertaken on a commercial basis.
- The generator could have offered itself PASA available and available in daily bids. Consistent with the stated intention to minimise distortion the generator would logically be offered at the Market Price Cap, however by offering itself available it would be included in calculations of whether sufficient reserves were available both in planning and operational processes.
  - By offering itself available the generator would be exposed to unexpected or transient generation targets as well as AEMO invoked constraints. Whether dispatched at its priceband or constrained on the generator would not be able to claim compensation if the cost of generating was greater than the revenue achieved.
  - Simply by being available the generator would increase reserves. This would allow AEMO to dispatch alternative, commercial generators which are currently required to be held in reserve (in the absence of the SA Government generator being available to the market).

It can be seen that there are potentially strong incentives in the current market design to make investment and operational decisions which reduce AEMOs ability to operate the market without safety net measures. Currently these incentives are tempered by the uncertainty over whether AEMO will procure RERT contracts, however any proposal to formalise minimum or standard procurement volumes would risk exacerbating these risks.

Notably, AEMO have released a draft high level design for strategic reserves[29] which proposes to procure reserves regularly, well in advance and potentially without an identified period of low reserve as a trigger. Stanwell does not consider a regime where such costs are incurred without an identifiable reason would be in the long term interests of consumers.

Timing of emergency reserve procurement

Summer 2017-18 represents a changeover in the RERT procurement rules, being the last time long-notice RERT contracts could be entered into. Under the current Rules AEMO may now only enter contracts with RERT providers between 10 weeks and 3 hours of the forecast reserve shortfall, but may convene a panel of potential providers at any time.

Stanwell consider that these arrangements reflect the volatility of forecasts in the electricity market. Between June and August 2017 AEMO's demand forecast for 2018 in Victoria increased almost 200MW from 9,665MW to 9,859MW[30]. AEMO released tenders for RERT in July 2017 and September 2017 following the release of these forecasts, and in November 2017 announced that 1,150MW of reserves

[27] Assuming it is capable of being made available within 24 hours. This may be achievable through higher staffing and/or fuel procurement arrangements.
[28] AEMO Summer operations 2017-18 report, page 14

[29] AEMO, *STRATEGIC RESERVES HIGH LEVEL DESIGN*, December 2017
[30] Neutral scenario, 10 POE

were expected to be available including 885MW in Victoria[31]. Stanwell understands that much of this capacity was providers on the short notice panel and so do not receive revenue unless exercised[32].

While in this case the forecast demand increased (logically decreasing reserves), declining demand forecasts are equally likely. Depending on when reserves were procured there may have been materially different procurement decisions made, and to the extent that availability payments were included in those contracts consumers would have been exposed to this forecast volatility.

Recent investments have also been observed on timelines which were historically considered unachievable. Early procurement of "emergency" reserves may dilute or remove the investment signal for short lead time commercial investments.

Efficiency through standardisation

AEMO and ARENA have recently conducted a trial whereby ARENA provides upfront capital support for potential demand response providers in return for the providers registering on AEMOs short notice RERT panel using standardised contracts. While not all RERT contracts for this summer are standardised, Stanwell understands that requesting reserves and entering contracts has been significantly streamlined compared to previous periods of low reserves.

AEMO's high level design of strategic reserves[33] also proposes an approach based on standardisation, but allowing for consideration of non-standard offers. Stanwell expects that regardless of the mechanism, the procurement process could benefit from preferring standardisation of contracts.

Efficient procurement volume

Stanwell acknowledge that there is a level of uncertainty in regards to what volume of reserves AEMO can and do procure under the RERT mechanism. AEMO have indicated that their internal procedure is to develop a RERT schedule with the aim of meeting the largest forecast reserve shortfall (i.e. below the LOR2 trigger level) in a period plus 10 per cent[34], however it is unclear how this is implemented.

Going forward, we consider the risk of this uncertainty is largely overcome by the removal of arrangements requiring bespoke agreements and availability payments. Entering short notice reserve contracts from panel members with standardised contracts, in response to clear triggers is likely to allow AEMO to minimise cost and distortion as required by the Rules. There may also be benefit to incremental improvements in AEMO's reporting of RERT events.

What level of reliability at what cost?

Stanwell supports the AEMC's position in relation to delivering a high level of reliability at an efficient cost.

> "*In considering the need for changes to, or a replacement of, the RERT, it is important to be clear about the problem. For example, if the concern is that community or political expectations have changed such that load shedding is no longer acceptable, then this is unlikely to be best addressed through a strategic reserve. This concern would be more appropriately, and efficiently, addressed by considering whether or not the existing reliability standard is set at the appropriate level.*"[35]

Regardless of the framework there will always be the potential for unserved energy to result from un-forecast events, and Stanwell considers that spending money on reserves just in case something outside reasonable expectations occurs is not in the long term interest of consumers.

By comparison, procuring additional resources in response to an identified risk is likely to be in the long term interest of consumers, subject to the cost of those resources being less than the value consumers place on continuous supply.

The current rules contain a number of different mechanisms limiting the potential cost of actions taken to maintain reliability in the operational timeframe, however there may be benefit in providing additional clarity in this regard.

[31] AEMO, *Summer operations 2017-18*, November 2017, Page 14
[32] Excluding ARENA payments where applicable.
[33] AEMO, *STRATEGIC RESERVES HIGH LEVEL DESIGN*, December 2017
[34] AEMO, *NEM EVENT – ACTIVATION OF UNSCHEDULED RESERVES FOR VICTORIA – 30 NOVEMBER 2017*, February 2018
[35] Interim report, page 131

Effective deployment of reserves

Once reserves are identified and defined, effective deployment will be critically linked to forecast accuracy.

High profile reliability events occurred on 8 February 2017 in South Australia where AEMO directed involuntary load shedding at the mass market level and 10 February 2017 in NSW where an industrial load was curtailed.

In South Australia it has been well reported that there was a significant change to forecast wind conditions late in the afternoon. Because a number of older wind farms in South Australia are non-scheduled this manifested itself as both an increase in demand (less non-scheduled generation) and a decrease in availability (less semi-scheduled generation) causing reserves to decrease rapidly and significantly. While there were resources available they could not be activated given the lead time between the change in forecast and the time of system need – that is, there were sufficient resources had there been an accurate short term forecast earlier in the day.

Had the same conditions occurred but with the South Australian Government owned generator having been installed it is unclear whether the results would have been different. As noted, the generator is unavailable to the market but can be activated under a RERT contract arising from AEMO intervention; however short notice RERT contracts relate to situations where AEMO have between 3 hours and seven days notice of a projected shortfall in reserves[36] and it is unclear that sufficient notice would have been available for AEMO to activate a reserve contract.

In NSW, reserve forecasting was primarily affected by a number of unplanned outages at scheduled generators. The station trip at Tallawarra and the failure to start at Colongra are unlikely to have been affected by alternate reliability obligations or safety net. Similar to the events in South Australia, it appears that even had a RERT panel existed at the time AEMO may not have had sufficient warning to procure reserves under contract.

As identified in the Interim report, the AEMC have recently agreed to an AEMO initiated rule change request which is expected to make LOR declarations more conservative than those that were in place during February 2017. Despite the rule change having been made there has been no information made available to determine whether the revised Rules would have been expected to help alleviate these events.

It appears likely in principle that more conservative LOR declarations in the lead-up to these events would have lead to additional contracting of short notice RERT resources, limiting the potential benefits of structural changes to the safety net arrangements. Conversely, the more conservative declarations may increase RERT procurement costs to inefficient levels over the long term. With the revised guidelines not operational at the time of writing and no publicly available analysis of back-casting results there is no way to compare the relative merits of alternative arrangements.

[36] Interim report page 132.

5. Day ahead markets

Stanwell generally agrees with the AEMC's analysis of day-ahead markets.

Stanwell agree that the current NEM arrangements are similar to European-style day-ahead markets, with limited benefits likely to accrue from a change to market design. We also agree that there is no impediment for the existing forward market to develop a day-ahead contract if it were deemed necessary by the market.

In relation to US-style day-ahead markets, Stanwell agree that the problems that a day-ahead market may address in the NEM have not been fully demonstrated. While different, US-style markets do not appear better able to adapt to the rapid changes impacting the NEM.

Stanwell notes that one proposed benefit of a day-ahead market – the concentration of liquidity at a fixed point in time – appears contrary to the proposed NEG design and requirements for large generators to announce closure plans at least three years in advance. Each of those processes would benefit from longer term contracting rather than concentrating liquidity in the very short term.

We agree that the problem that day-ahead markets would solve must be fully identified and alternatives considered alongside day-ahead markets. We also agree that the simple bid structure in the current market internalises the complexity of generators' non-linear cost profiles and may be more efficient than block bidding. However if block bidding is considered more efficient by some entities it will be important to distinguish whether the benefit accrues from the day ahead market per se or the ability to optimise generator bids over more than one dispatch or trading interval.

Security and reliability through the contract market

> *"Contract markets not only smooth cash flows of market participants to manage their risk, but support reliability by informing participant investment and operational decisions."*[37]

Stanwell agree that contract markets should inform investment and operational decisions, which in turn should support reliability. These markets provide a type of consensus forecast of market conditions going forward, allowing supply resources (including demand side participants) to evaluate whether their services are required or valued. Suppliers who can sell a contract and operate profitably are likely to do so, and having sold the contract are more likely to be available to "defend" their sold position. Suppliers who cannot operate profitably at the market price may either exit the market or remain available while adopting a higher risk operational strategy (requiring higher revenue). Critically, in relation to reliability the price at which generation is offered is largely immaterial, as long as it is offered available to the market operator. That is, while the presence of a contract is likely to support reliability, the absence of a contract does not necessarily lead to a reduction in reliability.

In their submission AEMO says that "*contract markets can provide hedges, but do not provide the necessary transparency to the system operator to operate a <u>secure and reliable system</u>* [emphasis added]"[38]. As contracts are typically a financial derivative not a supply agreement this is appropriate. The seller of a contract may or may not be a generator and the buyer may or may not be a Market Customer. A contract between Westpac and Macquarie Bank is identical[39] to a contract between Stanwell and AGL, and neither will directly affect the ability of the system to provide electrons at any point in time to any point in the network. Contracts may also include bespoke arrangements which suit the parties involved but would be difficult to integrate with market operation decisions.

With reference to a potential day-ahead market, AEMO appear to envision short term contracts between participants and the market operator using highly standardised terms. Stanwell consider that such an arrangement would be less useful and efficient than current arrangements due to the level of prescription required by the operator. As noted in relation to forecasting above, AEMO are already requiring information from battery storage that cannot be represented in generator bid files, and Stanwell consider that improvements to acceptable offer parameters will be of greater benefit than replacing one prescriptive form of offer with another.

Contract markets also do not typically provide hedging for system services necessary for reliability such as Frequency Control Ancillary Services, Network Support Control Ancillary Services and System Restart Ancillary Services. However should contracts for these services be required, Stanwell expects that the forward market would evolve to meet this need. It is likely that the lack of financial markets

[37] Interim report, Page iii

[38] Interim report, Page 163

[39] Subject to terms and conditions such as credit support.

in relation to these services reflect the very small size of FCAS markets relative to energy demand and the lack of transparent pricing for the other services.

Pre-dispatch transparency for AEMO

AEMO says that "*contract markets can provide hedges, but do not provide the necessary transparency to the system operator to operate a secure and reliable system* [emphasis added]"[40]

As the AEMC understands, AEMO receives detailed information from scheduled and semi-scheduled participants in advance of dispatch in relation to their capability and intentions[41]. This implicitly includes participants' contract position which rarely changes significantly within a couple of days of dispatch. The original commitment intentions of scheduled generators may not be realised in dispatch due to a material change in circumstance and subsequent rebidding, however the same changes in circumstance would affect a day-ahead market.

Moreover, under current NEM design, scheduled market participants are assigned the volume risk, and therefore revenue risk, associated with the accuracy of forecasting. If AEMO over-forecast or under-forecast demand in a day ahead market there will need to be a balancing market to manage the impact, with consumers paying for both the day ahead schedule and balancing market cost[42]. Under the current single pass model these balancing adjustments may be payments avoided, rather than added.

The AEMO submission also indicated that "*day-ahead markets have the potential to promote demand-side participation. This is because increased transparency on system requirements may give customers more time to prepare and put alternative arrangements in place.*"[43] Stanwell notes that this statement is only applicable to a subset of potential demand side participants with many able to respond immediately or at much shorter notice. The demand side resources identified in the ARENA-AEMO trial are all able to respond within one hour of a signal and many within ten minutes. The primary benefit to any resource from a day ahead market would be certainty of revenue from a scheduled activation, which consumers would pay for whether required or not.

Portfolio diversification and risk

The AEMC is rightly concerned about the amount of capacity participants may be able to provide to a US-style day-ahead market[44]. A design for a day-ahead market which requires firm commitments from individual generators which are physically and financially binding increases the financial risk to generators.

Under the current arrangements, large portfolio generators are able to hedge to a high level given the geographical and physical diversity of the portfolio. If the design for a day-ahead market requires physical and financial commitments from individual units then for the same risk exposure, generators will contract less. This adds to costs for consumers.

Nodal pricing and firm transmission rights

As identified by the AEMC, US-style day-ahead markets feature nodal pricing and firm transmission rights as complementary design reforms. Nodal pricing is not currently a feature of the NEM (other than the single nodal price per state) and is not consistent with existing policy such as the Uniform Tariff Policy in Queensland.

A change to nodal pricing, if accepted at the policy level, would be costly and complex and highly disruptive to financial markets. Stanwell consider that there would need to be a strong cost-benefit analysis to support even considering such a change to market design and policy, noting that the increase in DER is already challenging the market operators' ability to identify system resources and manage flows securely.

[40] Interim report, Page 163
[41] Interim report, Page 174 - 175
[42] Interim report, Page 161
[43] Interim report, Page 163
[44] Interim report, Page 180