RESPONSE TO AEMC FIVE MINUTE SETTLEMENT DIRECTIONS PAPER

MAY 2017

Stanwell Corporation Limited

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Executive Summary

"Given the change occurring in the NEM, the Commission's initial position is that:

The adoption of five minute settlement would have a material benefit that is likely to outweigh the cost.

…

The Commission's initial position is subject to stakeholder feedback on detailed immediate and future costs and benefits of five minute settlement."[1]

Stanwell welcomes the Commission's acknowledgement that its initial position is subject to feedback on detailed costs and benefits of such a change, and welcomes the Commission's decision to publish a directions paper prior to a draft determination in order to aid in the formulation of such feedback from stakeholders.

Stanwell agrees with the Commission that there are in-principle gross benefits to be derived from aligning dispatch and settlement periods.

Stanwell also agrees with the Commission that the proposal to shorten the settlement period from 30 minutes to five minutes would likely result in costs and/or benefits accruing to most market participants[2].

Despite the clarification of issues surrounding symmetry, optionality and metering in the Directions Paper, there remains little clarity with regards to what is actually being proposed. There are hundreds of references to "Trading Interval" in the Rules and there has been no public discussion as to what legal drafting is being proposed and what consequential impact this may have on other processes.

Stanwell has also yet to see any evidence to support the Commission's expectation that the benefits are likely to outweigh the cost of such a change. The Commission's brief analysis conducted to date appears to leave a number of unexplored issues which Stanwell has identified in this submission. The current market frameworks, including the rules for scheduling and aggregation, do not appear suitable to ensure that the benefits of five minute settlement can be realised. There has been significant focus on the potential benefits to certain participant types, but little effort expended on:

- investigating the changed incentives on participants,
- changes to risk profiles[3],
- the assumptions necessary to derive modelled benefits, or
- the risks associated with the change.

We consider it critical that the Commission's decision supports the economy and public welfare. Poorly implemented or rushed changes to fundamental market design will only add to cost pressures which are already challenging both producers and consumers ability to stay in business and in turn potentially impact the ability of AEMO to maintain a secure and reliable system.

Before making a change of this nature we expect the Commission to have a high level of confidence that the market operator, regulator and participants are all capable of being ready to make a smooth transition between market designs. Such confidence is likely to require iterative development of the scope, understanding of the impacts and a clear implementation plan to ensure that unintended consequences are avoided.

[1] AEMC, 5 minute settlements, Directions Paper, April 2017, pages iv-v
[2] Directions paper, page 11.
[3] With the exception of risks to cap sellers performed by Energy Edge.

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1 Impact on Stanwell Corporation Limited of rule change

1.1 Stanwell's generation portfolio

Stanwell is well placed to respond to both short- and long-duration price volatility.

Stanwell owns and operates a diverse portfolio of generating units – 17 scheduled and three non-scheduled units connected to the National Electricity Market (NEM):

- Nine large scheduled coal fired units (Stanwell, Tarong, Tarong North Power Stations) are typically online and offer a combined ramp rate in the order of 30MW/minute (150MW per dispatch interval). Subject to loading and mill configuration each unit can typically sustain full ramping for up to 40 minutes and maintain output for as long as required by the market;
- Swanbank E Power Station is currently in cold storage but when operating is scheduled and offers ramp rates of around 11MW/min;
- The four scheduled Kareeya Power Station units operate in synchronous condenser mode when not generating for market purposes, allowing them to ramp from "rest"[4] to full load in a single dispatch interval;
- The two scheduled Barron Gorge Power Station units have varying capabilities at different times of day and year (due to the surrounding environment, safety, third party commitments) but are typically bid available;
- The scheduled Mackay Gas Turbine is a liquid fuelled aero derivative which can reach full load (34MW) in a single dispatch interval as reflected by its availability for the 5 minute raise FCAS service (13MW);
- The non-scheduled K5 and Wivenhoe units are not price responsive;
- The non-scheduled Tarong Gas Turbine has historically been used for black start capability and while potentially price responsive does not have control systems in place to allow it to be reliably activated at short notice;
- Stanwell controls or facilitates non-scheduled demand response in relation to a number of large customer sites.

1.2 Upgrades to Stanwell's Information Technology systems

Stanwell's IT environment has been developed incrementally in line with the development of the NEM and related markets and through mergers and acquisitions. Given the stakes, Stanwell continuously reviews its systems to ensure they are fit for purpose, streamlined and simplified. Despite this, Stanwell's IT systems are complex, reflecting the diverse demands of stakeholders, the immense volume of data from disparate sources and the importance of the information. While by no means comprehensive, a high level view of Stanwell's Trading systems is as shown in Figure 1 below.

As part of its drive for continual improvement, Stanwell maintains an "IT roadmap" which incorporates the interaction between major projects and minor or routine actions and extends for multiple years.

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[4] When operating in synchronous condenser mode, Kareeya Power Station has one unit generating 5MW and the remaining three units at zero MW.

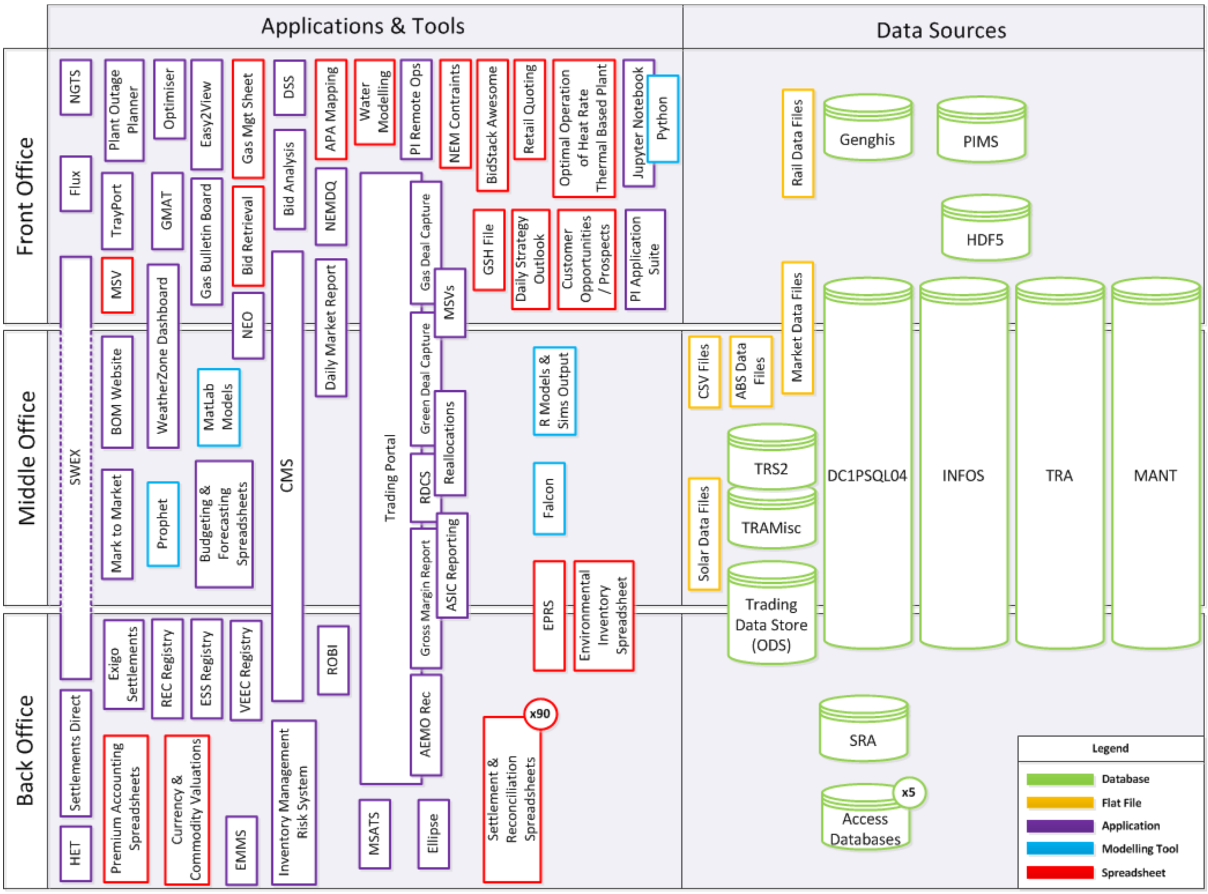

Figure 1: High level overview of Stanwell's IT systems supporting the Trading function

The roadmap does not presently include any budgeted expenditures for changes required due to regulatory change - such as that which will be incurred as a result of the 5 minute settlement rule change.

Stanwell is well placed to provide comment on the potential impact to systems resulting from a proposed rule change, however we do not have sufficient information in relation to the current proposal to develop detailed estimates.

One roadmap activity - the "Contract Management Platform" project - is primarily a technology update of the CMS system shown in Figure 1. It has an implementation and testing timeframe of 18 months however this is the result of approximately 2 years of scoping, technology review and refinement. Despite this effort, approximately 6 months into the proposed implementation period the project is still in the embryotic stage, confirming technology selection and business case development.

Much of the effort and expense in Stanwell's IT upgrades is in relation to ensuring that the new system integrates with existing tools in order to avoid the redevelopment of those tools. However if a change to the settlement period were to proceed, many of the existing tools would require simultaneous redevelopment, adding cost and complexity not only through the redevelopment of those tools, but in the integration and testing of multiple newly developed systems. No matter how well defined the interface between systems is, integrating two new systems requires more detailed testing and assurance than integrating a new system to an existing one.

A more frequent settlement period will also require more robust ICT infrastructure to support increased transaction volumes and mitigate business risks. Current ICT infrastructure architecture, resource levels and support contracts will need to be reviewed which will likely result in wholesale changes across the technology stack.

Subject to confirmation of the specific rule changes proposed, Stanwell does not consider that the 3 year transition proposed in the Directions paper would be sufficient for the redevelopment of IT systems.

While specific estimates are not available Stanwell considers that the above commentary provides contextual information in relation to the time, effort and expense likely to be required in response to the proposed rule change. Stanwell agree with the broad estimate of "tens of millions of dollars" in the Energy Edge report[5], but at this stage are unable to estimate how many tens of millions. Further, the estimate provided at the forum of industry wide IT costs exceeding a quarter of a billion dollars[6] is likely to be realistic.

2 Obtaining the benefits of 5 minute settlement

While there appears general agreement that there are in-principle gross benefits from aligning dispatch and settlement intervals, there has been little apparent analysis on the magnitude of those benefits or the conditions precedent for achieving them.

From the analysis presented to date, Stanwell has identified four pre-conditions necessary for obtaining the benefits of the proposed change to 5 minute settlement.

2.1 Scheduling to reduce artificial price swings

Generating units and loads in the NEM can currently be registered as scheduled, semi-scheduled, non-scheduled or exempt from registration. Non-scheduled price responsive generation and load can contribute significantly to the intra-Trading Interval price swings observed in the NEM due to its lack of transparency to the market operator. In not accounting for the impacts of non-scheduled generation and load, the Commission may be overestimating the effect of the proposed rule change. The sharpened financial incentives of 5 minute settlement are likely to give rise to increased non-scheduled participation with consequent artificial price swings.

In the example on pages 19-20 of the Directions Paper, two scheduled generators offer output at different prices and with different response characteristics. During a Trading Interval each unit sets the marginal price for one or more dispatch intervals. Consider the same scenario, but with the "rapid response" generator non-scheduled.

During the first dispatch interval the fast response generator is unable to physically respond and AEMO is unable to provide a target to the rapid response generator to increase output as it is non-scheduled. A third generator is therefore required by AEMO's dispatch engine NEMDE to set the price – probably at a level significantly higher than that offered by the rapid response generator in the example. Because this price is set high – say at the Market Price Cap (MPC) of $14 000/MWh - the price sensitive non-scheduled rapid response generator is likely to increase output. However the response of the non-scheduled generator does not change the underlying demand being served, so a scheduled generator somewhere else must be targeted to reduce generation– probably through the regulating lower ancillary services market – in order to keep the frequency close to 50Hz.

During the second dispatch interval, AEMO will apply a persistence forecast to the non-scheduled rapid response generator. That is, AEMO will assume this generator continues to produce at the current level and will therefore dispatch scheduled generators around this new assumed reality.

1. The fast response generator will continue its start-up sequence with a zero MW target as defined by its fast start inflexibility profile;
2. The third generator that is offered at the MPC will be available to maintain output or ramp down;

[5] Page 86, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[6] Slide 5, Russ Skelton and Associates presentation 2, AEMC 5 minute settlement public forum, May 2017

3. The scheduled generator which provided regulating lower in the first dispatch interval will be available to be targeted up; and
4. Demand will be lower due to the assumed presence of the non-scheduled rapid response generator whose output is subtracted from demand for scheduling purposes.

NEMDE will set a low price reflecting the increased availability of low cost generation (the scheduled generator which provided regulation lower is available to be targeted up) and decreased demand – say $50/MWh. The third generator offered at MPC will be targeted down and the scheduled generator providing regulation lower is not targeted up since the non-scheduled generator is assumed by AEMO to meet the marginal demand.

However the non-scheduled rapid response generator will likely respond to the $50 price signal by ceasing production meaning that another scheduled generator – a regulation raise provider – will have to ramp up to serve demand and maintain frequency.

Depending on which generators are providing the regulating raise and lower, by the end of the second dispatch interval there may be cheap generation constrained off, expensive generation constrained on, both or neither. And that is before the fast response generator complicates things by increasing output in the third dispatch interval - regardless of price - consistent with the commitment given in the first dispatch interval. The fast response generator although slower, will supress price over a long period. It is important that incentives for slower response, long acting generation is retained under 5 minute settlement as explained in Section 4.5.

The extreme price, artificial price swings and altered expectation of conditions also increases the likelihood of rebidding behaviours such as disorderly bidding and “piling in”, driving further price swings.

Stanwell considers it incumbent on the Commission to ensure that before five minute settlement is recommended that artificial price swings such as that identified in this example is appropriately analysed with the assistance of AEMO. If 5 minute settlement is implemented it must be accompanied by appropriate scheduling arrangements in order to minimise artificial price swings.

2.2 Registration, transparency and aggregation

While current scheduling definitions relate to individual units, or aggregated units which are electrically close, significant investment is occurring in “behind the meter” generation and storage (known as Distributed Energy Resources or DER). AEMO’s submission to the Finkel review has highlighted the difficulties emerging in managing a system with increasing and non-transparent DER.

One example of this was provided by Reposit in its presentation at the public forum, however there are a number of providers using similar models and/or resources. The example was of a pricing event in South Australia that was responded to by the approximately 170 storage devices controlled by Reposit in that State. Assuming each battery has a 5kW discharge capability this equates to almost 1MW of response – enough to unilaterally affect pricing outcomes. Despite Reposit’s stated intent to become scheduled and sell cap products at a future date, the devices are currently non-scheduled and to Stanwell’s knowledge do not provide AEMO with indications of their price responsive intent or capability (price level, capacity to respond, charge, location etc).

There may have been significant market benefits had this 1MW of generation been able to be taken into account proactively by AEMO. 1MW of schedulable generation may have lowered the extreme high prices, and 1MW of schedulable load (2MW if you include the ability to schedule generation down and schedule load on) may have reduced the extent of the negative prices. In both instances, the extreme calls on scheduled generator capability would likely have been smoothed.

Further, if the high prices had been the result of a transmission constraint limiting the output from low priced generation, the discharge of 1MW of non-scheduled storage on the constrained side of the transmission line may have affected AEMO’s ability to manage system security. Given Reposit’s stated growth target of 1GW of storage by 2020 the problem is likely to become significant.

Reposit also provide an example of the potential financial benefit to behind the meter storage from the move to 5 minute settlements. The example suffers from "pay for target" analysis as described in Section 4.1 but shows a 20-30% increase in returns from 5 minute settlement in circumstances where dispatch interval prices swing from close to the market price cap to close to the market price floor within a Trading Interval. Regardless of the specific numbers, the example shows that a change to 5 minute settlement would increase the returns available to behind the meter non scheduled storage with the potential to accelerate the uptake of these devices. If these devices remain non-scheduled, artificial price swings is likely to result (as explained in Section 2.1) and system security will be more difficult to manage.

Stanwell encourages the Commission to ensure that the proposed rule change does not make AEMO's operations unnecessarily difficult by incentivising non transparent, potentially aggregated, price responsive DER. If 5 minute settlement is implemented it must be accompanied by appropriate registration, transparency and aggregation arrangements in order to minimise artificial price swings.

2.3 Metering

In proposing to make a More Preferable Rule Change, the Commission has made a number of alterations to the original rule change proposal in an attempt to make it more likely to enhance the NEO. One of these alterations is to propose the mandatory use of 5 minute resolution revenue metering for connection points other than those settled through a net system load profile.

Stanwell supports this alteration, noting that the obligation to implement such a change will fall on the Metering Provider combined with the new metering coordinator role being introduced to the rules from 1 December 2017. The proposal to align the requirement to provide 5 minute data to the frequency of metering inspection and testing requirements appears sound and is likely to reduce costs in relation to most affected meters (compared to forced adoption).

Stanwell also recognises the potential benefit provided by a rollout of five minute metering for both generation and loads, in that AEMO will have greater visibility after the fact of the actions of participants who do not currently provide high resolution data. However while this will provide AEMO with greater transparency about *what* has happened, it will not improve the forecasting of price-sensitive non-scheduled participants and therefore will not improve predispatch greatly unless other Rule Changes are made.

While unlikely to have a significant direct effect on Stanwell's business, the proposal to allow a transition period where there will exist both 5 and 30 minute settled customers is likely to add to costs for retailers. Stanwell considers that having customers on both 5 and 30 minute settlement may be unnecessary with an adequate transition roadmap as discussed in Section 2.4 below. If customers are to be temporarily on both 5 and 30 minute settlement, the proposal to recover imbalances through intra-regional losses appears acceptable.

In relation to a possible exemption for non-AMI type 5 meters, Stanwell notes that one of the drivers of the Power of Choice metering rule change was to enable and encourage the uptake of advanced metering, so some and possibly many of the 600 000 meters noted are likely to be changed within 5 years. It may be counterproductive to provide an exemption for this class of meters where an appropriate transition timeframe is provided.

2.4 Adequate transition period

Changing market design from 30 minute settlement to 5 minute settlement is a major undertaking and any implementation should allow for an adequate transition period. This period should allow for the development of preconditions such as arrangements for scheduling, registration, aggregation and transparency discussed above as well as non-Rules issues such as IT system redesign and financial market impacts.

The proposed change is not something that the Commission should mandate and hope it works. There should be a high level of confidence that the market operator, regulator and participants are all capable of being ready to make a smooth transition between market designs. "*Given the scale of the implementation and potential impacts on market participants it may be desirable to have a longer timeframe for commencement in order to allow effective planning, design and implementation.*"[7]

Adequate transition timeframes may vary in relation to different aspects of the rule change, for example the lead time for some metering types appears significantly shorter than the lead time required for IT upgrades. Similarly, there may be areas where there are benefits from one entity – for example AEMO – reaching a certain level of system development before the broader industry progresses. One example of this would be in relation to the structure of tables in the Infoserver database which currently includes similar but not identical information in separate tables in relation to dispatch intervals and trading intervals. If changes are to be made to the data and schema design they should be defined prior to participants scoping the changes to their internal systems.

Stanwell consider that it would be appropriate for the Commission to develop an implementation roadmap, setting out no-regrets issues such as the proposed metering changes as well as pre-conditions and decision gateways for potentially expensive issues.

2.4.1 Transition required for contract market

As discussed in Section 3.3 Energy Edge have estimated that the rule change is likely to result in a reduction in cap market issuance in the order of 23%. The AEMC states, "*A substantial, immediate reduction in the supply of cap contacts is likely to increase wholesale prices and damage retail competition. A reduction in caps would increase barriers to entry for retailers, create incentives for market participants to manage risk via vertical integration or horizontal integration, and increase retail market concentration. This will result in higher prices for consumers.*" [8]

In order to negate the negative effects of a reduction in cap market liquidity, Stanwell suggests the transition be long enough to allow new suppliers of caps to emerge that would not otherwise participate in this market. This idea is supported by Energy Edge, "*we would suggest that such assets are in place prior to the implementation of the proposed rule change to ensure that the market is not left with a shortage of cap contracts that will result in retailers potentially having to manage their load flex with instruments that either increase price or increase risk.*" [9]

To determine the actual transition time, Energy Edge suggests the AEMC consider the lead times associated with the construction of sufficient additional very fast start generation assets (eg pumped hydro, batteries or other technologies) [10]. At the forum it was suggested by the AEMC "*If we are*

talking about changing assets, investing in new things, the lead time of different technologies is something that we have considered. You could put in utility scale batteries for a few months, if necessary, diesel is maybe a year. You're looking at major changes or new gas turbines for several years. So the three years was arrived at with that in mind." These references appear to be to construction lead times, assuming economic viability and planning approvals.

Regarding approvals for technologies that will fill the cap void Energy Edge states, "*Currently Pump Storage Hydro are very economic from a feasibility study perspective but other restrictions particularly associated with environmental and land holder issues create substantial lead times and adversely impact their ability to be part of the solution without supportive policy and regulatory changes.*

" [11] This suggests that it will be significantly more than 3 years for these technologies to be viable and therefore installed and contributing to the supply of caps.

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[7] AEMO 5 minute settlement working paper, November 2016, page 8
[8] Page iii, AEMC 5 minute settlement Directions Paper, April 2017
[9] Page 86, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[10] Page 86, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017

Similarly, the Commission have noted the potential difference between a market based implementation and a centrally directed investment. *"Secondly, to Emma [Tesla], the examples you used, if I understood them correctly, the counterparties to your contracts were some central authority, i.e. investment wasn't made on what we'd refer to as being market-driven, they were made on the basis of what some extra authority thought was required for consumers, rather than consumers deciding for themselves. To what extent does the deployment of the sorts of technologies you're talking about depend upon there being an omnipresent planning God that does things for people as distinct from it being driven by a market?"*[12]

3 Significant unexplored risks

3.1 Cost to consumers from increased hedging costs

As explained by Energy Edge[13], generators and retailers have an incentive to enter into a high level of secondary market contracts (hedges) in order to reduce their revenue variability. Wholesale market costs (which are approximated by hedging costs for retail price determinations) generally account for about 25% of a small customer's electricity bill[14], more for a larger customer. Accordingly any change in hedging costs as a result of 5 minute settlement flows directly to a customer's electricity bill.

As explained at the public forum, the payoffs of caps will be altered increasing their intrinsic price, the supply of caps and swaps will be reduced at the same time that the demand for caps and swaps will be increased. These factors will all increase hedge prices. To the extent that the expected reduction in caps also causes a need for retailers to alternate with a more expensive swap, this will further exacerbate the increase in cost of hedging.

3.1.1 A 5 minute cap is mathematically more expensive than a 30 minute cap

As explained by Energy Edge[15] due to the elimination of the averaging effect, 5 minute caps will be more expensive (or equal) in cost to the 30 minute cap. Based on historical cap payoffs, Energy Edge calculated an increase in cap prices across the regions of between 4.2% and 46.5% as can be seen in Table 1. As these price increases are based on mathematical averaging effects, they will happen regardless of any other change in contract market supply/demand conditions.

Region	Cap payoff (30-minute settlement) ($/MWh)	Cap payoff (5-minute settlement) ($/MWh)	Difference (%)
Queensland	$14.12	$15.41	+9.1%
New South Wales	$1.48	$1.54	+4.2%
Victoria	$0.72	$0.82	+14.2%
South Australia	$10.55	$15.46	+46.5%

Table 1: Energy Edge calculation of difference in cap payoffs under 5 minute settlement

[11] Page 86, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[12] Page 64, Transcript of AEMC 5 minute settlement public forum.
[13] Page 7, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[14] https://www.dews.qld.gov.au/electricity/prices/bill
[15] Page 40, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017

3.1.2 Reduced supply of caps and swaps

Energy Edge have calculated a significant reduction in the volume of caps available to be sold across the regions. The reduction in cap volume is between 21% (NSW) and 30% (SA). These can be seen in Figure 2 and Figure 3 below.

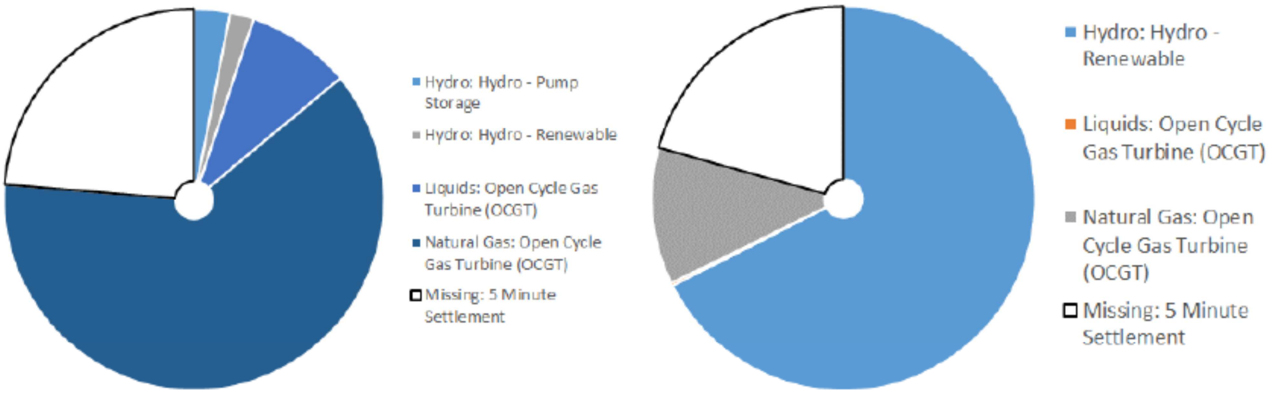

Figure 2: Energy Edge calculation of the 5 minute settlement cap volume QLD (left), NSW (right) showing missing caps compared to 30 minute settlement

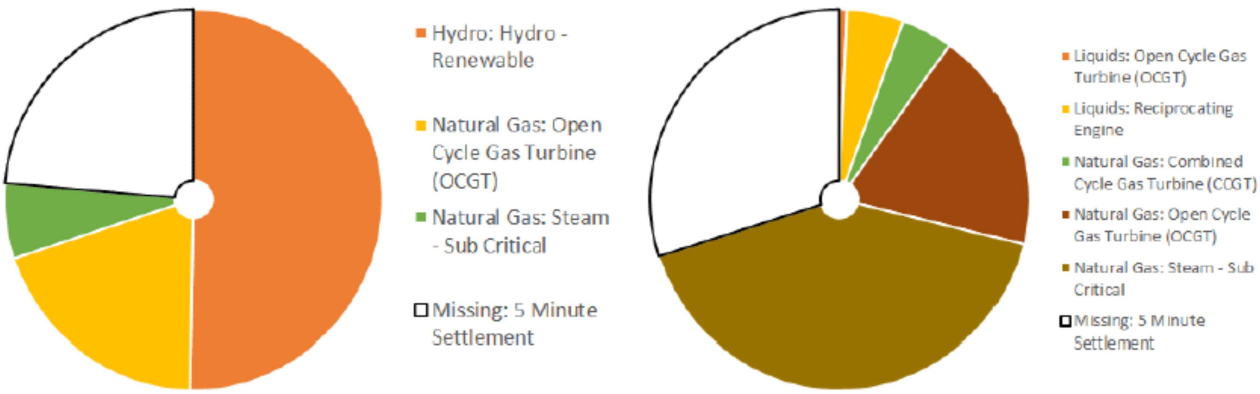

Figure 3: Energy Edge calculation of the 5 minute settlement cap volume VIC (left), SA (right) showing missing caps compared to 30 minute settlement

A significant reduction in cap supply, in markets which are already relatively illiquid and highly concentrated[16] is certain to result in increases in cap prices on top of the cap price increase due to the changed mathematics of the payout.

On top of the reduction is caps modelled by Energy Edge, is the likely reduction in swaps as a result of the rule change.

To determine the optimal hedge level, generators conduct detailed risk/return modelling considering historical and forecast price outcomes, the probability of trips, the recovery time from trip, the diversification within a generator's portfolio etc. Under 5 minute settlement a generator that trips has no opportunity to increase generation in other parts of the portfolio to reduce its uncovered contract exposure. This concern was also raised by ERM Power at the public forum:

[16] Page 78, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017

"If a large baseload generator trips mid-half hour now, they can ramp in extra generation and cover that outage so they can mitigate the potential loss of exposure to the pool price, if they have sold risk against that generation, or maybe fully cover it if they can ramp up in time. I would suspect, and I'm not responsible for dispatching baseload generation, they would be inclined to sell less hedges because I think it would be an increased risk to them in a five-minute market to hedge up to their current levels."[17]

3.1.3 Increased demand for caps and swaps

5 minute settlement will result in an increase in demand for swaps and caps thereby adding to the price pressures due to a reduction in supply.

Firstly, an increase in demand for caps will result from the reduced effectiveness of generators used as natural hedges within the portfolio of vertically integrated retailers. Retailers with this reduced natural hedge position will still need cover for their retail position and as a result will enter the market to obtain caps. This concern is echoed by Energy Edge:

"In the NEM there has been an increasing trend to vertical integration over the years (the use of generation assets as natural hedges for retail loads). Some of these vertically integrated generation assets are Hydro, OCGT and CCGT and therefore used as physical alternative (Natural Hedge) to a Cap. These natural hedges will also experience dilution in their effectiveness for covering a 5-minute Cap pay-off profile in the range of 20-30%. As a result, generators currently used as cap-like Natural Hedges will also contribute to the demand and supply imbalance that might arise for 5-minute caps as a financial product."[18]

Further increase in demand for hedges will come from retailers as a result of the elimination of the effect of averaging 30 minute demand. With 5 minute demand used for settlement, retailers will have a higher level of maximum demand to hedge to as mathematically, maximum 5 minute demand levels must be higher than (or equal to) maximum 30 minute demand. This phenomenon was also mentioned by ERM Power at the public forum:

"Thinking about how to hedge that large retail business I was talking about earlier, I'm not going to get any smoothing of that half hour. So the load I have to hedge doesn't get smoothed out by the ups an downs of that half hour. When we hedge, we are going to need to think about do we need to hedge up to a higher level. Is it to the probability of X situations that we need to be at the five-minute exposure level rather than a half hour level."[19]

3.2 System security

It is anomalous that there appears to have been no consideration given to the potential impacts on system security of the proposed change despite the numerous concurrent processes involving or being lead by the AEMC. While there are references to generation occurring at "times it is physically valued", this appears to relate only to energy market pricing rather than in the context of the physical requirements of system security. Further investigation is warranted into the potential non-viability of some synchronous generators under five minute settlement and the impact of changed investment incentives on inertia, system strength, frequency management and energy shortages.

In addition, the heavy "market economics" basis of this rule change appears at odds with recent regulatory processes and interventions. There appears to be a view amongst Governments that "markets have failed" and that markets can't be relied upon to ensure system security.

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[17] Page 50, Transcript of AEMC 5 minute settlement public forum.
[18] Page 61, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[19] Page 51, Transcript of AEMC 5 minute settlement public forum, May 2017.

This is illustrated by the AEMC's recent recommendation against an "inertia market", rather the AEMC have recommended a regulatory obligation for monopoly network businesses to maintain inertia[20]. The South Australian government has also directly intervened in the electricity market. The SA Government has limited the interconnector, proposed investment in generators and a system security imposition on retailers.

3.2.1 Reduced viability of gas fired generators

The rule change has the likely effect of reducing the viability of new and existing peaking generators and particularly Open Cycle Gas Turbines (OCGTs). Energy Edge describe two potential impacts:

> "*The potential rule change in combination with the higher cost of gas could severely limit the incentive for new investment in gas-fired power stations, particularly OCGTs. Furthermore, it has the potential to bring on the exit of gas-fired power generation due to the unsuitability of such assets to capture value.*"[21] and
>
> "*Most generation assets are debt funded and so are subject to banking requirements that reduce the level of income variability so that there is a higher probability that the asset will be able to repay debt... In the event that caps have been sold against these assets as a requirement of the financing obligations, the change to 5-minute settlement may invoke a renegotiation of the contract, due to some form of change of market pricing clause. Given our analysis that most of the fast start generators will not be able to physically back the same volume of caps, then this is likely to lead to one of two outcomes:*
>
> *1) The sale of a lower volume of 5 minute caps which, unless the premiums increase substantially, will result in a lower level of revenue for the generator.. This lower level of revenue is likely to be a concern for the banks as it may render the assets financially unviable. In such an instance, the banks will either refuse to finance the assets or charge a higher interest rate to cover the risk….*
>
> *2) The generator taking on a higher level of risk, and continuing to sell the same level of 5 minute caps that it had under a 30-minute settled market. Due to their reduced ability to capture pricing >$300/MWh, this will ultimately lead to diminished returns for the generator… this could lead to write-downs of asset values and bank debt write-offs, and possibly the sale of such assets at reduced prices to companies that can utilise them differently within a portfolio.*"[22]

OCGTs are synchronous generators and are typically utilised to avoid energy shortages over multi-trading interval timeframes. Their operation would typically support AEMO in managing emerging issues in relation to inertia, system strength, frequency degradation and energy shortages. Reducing the viability of such generators prior to alternative providers becoming available may be detrimental to system security, and this potential consequence should be considered by the Commission.

Stanwell does not own or operate gas fired generators that will be affected, however if system security is degraded it will negatively affect all generators and consumers.

3.2.2 Inertia and system strength problems

Stanwell is a member of the AEMC's System Security Markets Frameworks Review working group. Work conducted through this process has highlighted the current fragility of the electricity network caused by the transformation of the electricity sector. The AEMC stated in March 2017 "*The electricity industry in Australia is undergoing a fundamental transformation. The last decade has seen a rapid rise in the penetration of new generation technologies, such as wind farms and rooftop solar….. The widespread deployment of these new technologies is having major impacts on the operation of the*

[20] AEMC, System Security Market Frameworks Review Directions Paper, April 2017
[21] Page 83, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[22] Page 80, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017

power system, including two key system security issues. There is less inertia in the power system…. System strength is reduced in some areas of the network."[23]

Stanwell encourages the Commission to consider the interaction between the proposed changes to investment incentives and their work to support the retention of inertia and system security in the NEM.

3.2.3 Frequency degradation

Stanwell is also a member of AEMO's Ancillary Services working group. In addition to the problems noted above, AEMO are also now increasingly concerned about the degradation in system frequency. AEMO's charts (displayed in Figure 4 and Figure 5 below) presented to the Ancillary Services Working Group in May 2017 highlight the scale of the problem.

Stanwell encourages the Commission to consider the interaction between the proposed investment and operational incentives and AEMO's work in managing frequency, including potential requirements to limit the rate of change in active power.

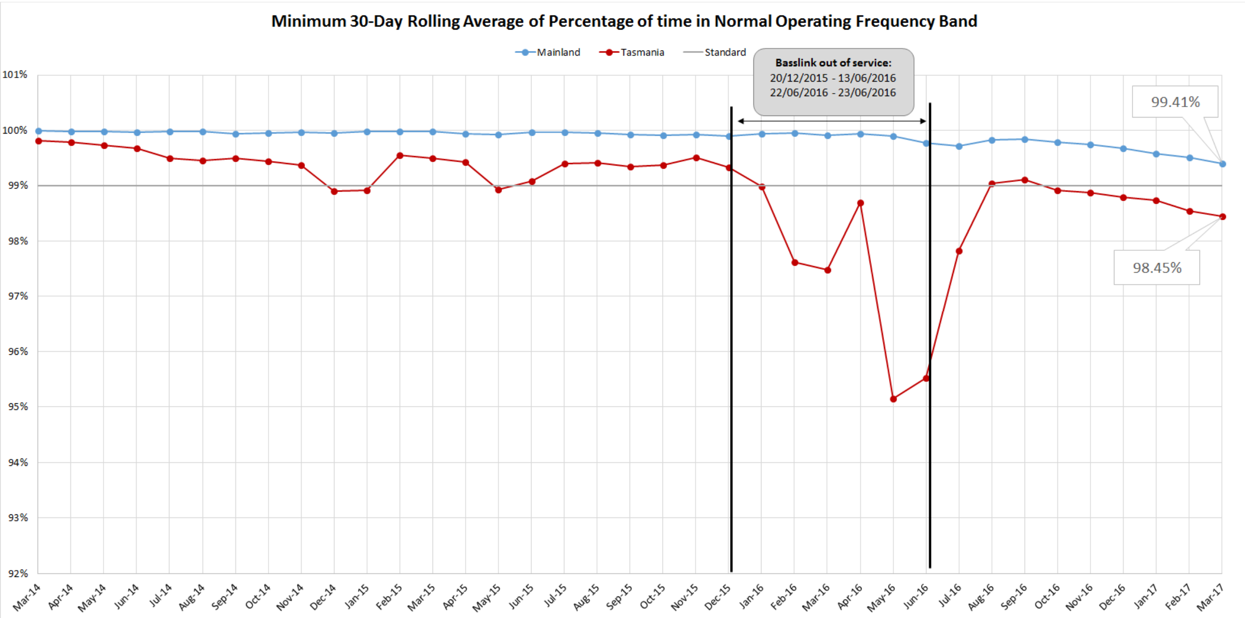

Figure 4: 30 day rolling average of percentage of time in normal operating frequency band[24]

[23] AEMC, Fact sheet: The need for a new power system security plan, March 2017

[24] Slide 5, AEMO, AS-TAG Frequency Performance, May 2017

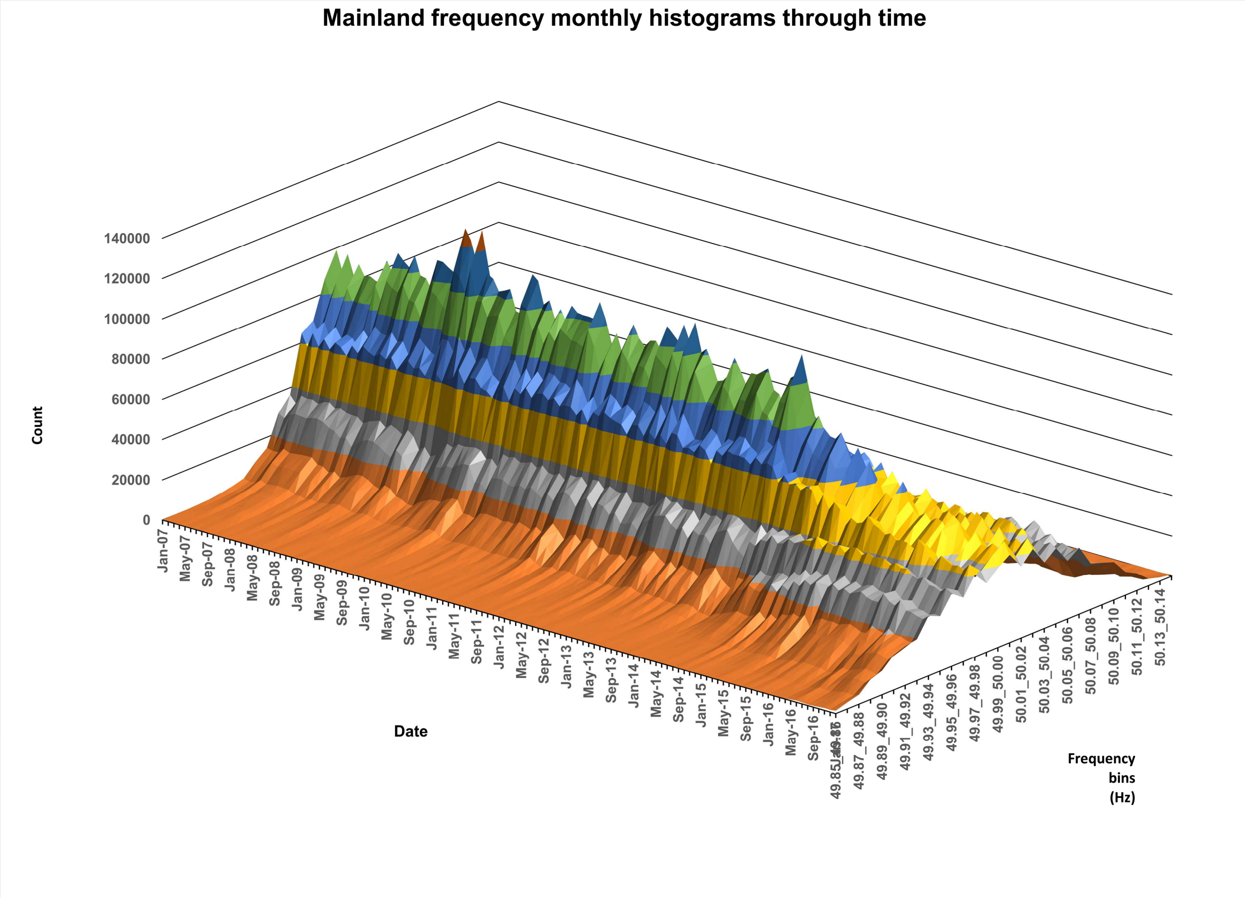

Figure 5: Mainland frequency histogram Jan 2007 - Jan 2017[25]

3.2.4 Energy shortages

There is also increasing concern regarding energy shortages, as highlighted by the events of summer 2017. Hot weather lead to difficult operating conditions, especially in New South Wales, South Australia and Queensland.

South Australia

On 8th February 2017, AEMO directed 100MW of load shedding in SA. This was due to demand being higher than forecast, wind generation being lower than forecast and the forced outage of a thermal generator. In considering all options to restore stability to the SA power system, AEMO asked the offline Pelican Point generating unit if it could come online. The owners advised AEMO that this would not be possible in the timeframe provided.

New South Wales

On 10th February 2017, NSW experienced very high summer temperatures. NSW operational demand peaked at 1630 hours at 14,181MW. This compares with record peak operational demand of 14,744MW on 1st February 2011. On the supply side, hot weather lead to deratings on thermal generation (3050MW [26]), the Tallawarra power station tripped (408MW) and the four Colongra

[25] Slide 6, AEMO, AS-TAG Frequency Performance, May 2017
[26] Calculated from Table 2, Thermal Installed Capacity (MW) minus Thermal Available Capacity (MW), AEMO, System Event Report NSW 10th February 2017, 22nd February 2017

generating units failed to start due to low gas pressure on their supply line (having run earlier in the day). Despite voluntary load shedding initiated at the request of the NSW Government (approximately 200MW), retailer initiated voluntary load shedding (at least 290MW), AEMO had to initiate forced load shedding of the Tomago Aluminium Smelter (290MW)[27].

Queensland

Although no forced load shedding occurred in QLD in summer 2017, AEMO declared a Lack of Reserve 2 (LOR2)[28] condition for the Queensland region at 5:00pm on Sunday, 12 February as demand increased to new records. At the time, the contingency capacity reserve required was 680 MW, while the minimum reserve available was 548 MW. The new 30 minute demand record set of 9,369MW is noteworthy as it occurred on a Sunday, usually the lowest demand day of the week.

The high demand led to periods of extreme volatility, there were 91 half hour trading intervals across the quarter that traded above $1000MWh, with the maximum price for the quarter being set at $13,882.77 on 13th January 2017. Demand side management was evident throughout the quarter with large industrial operations being able to fluctuate their load by approximately 300MW (up or down) which in turn added to price volatility. Faced with the high electricity prices, gas fired generators sought to increase generation, however there was significant competition for available gas supplies which in turn drove gas prices to high levels. The maximum Brisbane STTM price was $15.50GJ on the 10th February 2017.

The issue of energy shortages was highlighted at the forum, "*in three years time, probably the next baseload generator does leave us… large generation in New South Wales probably comes out around about the three-year mark… We do need synchronous generation. A lot of people do talk in how many megawatts and how many gigawatts of batteries will come in, but from a security of supply issue, we do need to think about megawatt hours and gigawatt hours, so there will be periods where we do have more of our traditional generation assets unavailable and we will need assets available with the right economic signal to come in and provide energy for sustained time periods.*"[29]

3.3 Reduction in contract market liquidity

Liquidity is the ease with which buyers and sellers can transact. If a large volume of a financial asset can be traded at close to market prices then the market is liquid. The electricity cap market is already relatively illiquid. A 23% reduction in cap supply is likely to decrease speculative trading and facilitation, further decreasing traded volumes. This concern was discussed at the forum, "*The final point is this 23 per cent drop in liquidity here in the cap markets. Liquidity is something which needs to be nurtured. It is a fragile thing. If you end up in a position where you have no liquidity, it's a difficult place to come back from and it's important to take that as a consideration.*"[30]

Liquidity takes time to develop, the current cap market liquidity has developed over more than 10 years. In comparison, the gas supply hubs of Wallumbilla and Moomba are relatively more illiquid having been developed more recently. At the time of writing the Moomba gas hub has still not traded despite having been accessible for nearly 1 year.

If there is a reduction in cap liquidity, this means retailers will have to manage their load flex with instruments that either increase price or increase risk. Stanwell agrees that, "*A reduction in caps would increase barriers to entry for retailers, create incentives for market participants to manage risk via*

[27] AEMO, System Event Report NSW 10th February 2017, 22nd February 2017
[28] LOR2 is where AEMO considers that the occurrence of a critical single credible contingency event is likely to require involuntary load shedding.
[29] Page 52, Transcript of AEMC 5 minute settlement public forum, May 2017
[30] Page 46, Transcript of AEMC 5 minute settlement public forum, May 2017

vertical integration or horizontal integration, and increase retail market concentration. This will result in higher prices for consumers." [31]

The AEMC assumes that new cap market liquidity will emerge through the supply of caps from new technologies. Stanwell note that AEMO have begun publicly discussing the potential to limit the rate of change of generation in order to manage potential impacts on system frequency from responses to extreme price events[32]. This may limit the ability of any technology to manage the risk of having sold significant volumes of caps in relation to a generating plant which is typically at rest.

The AEMC says, "*it is unclear whether they [new technologies] would replace the existing supply of caps that gas peaking generators currently sell.*"[33] As discussed in Section 2.4, Stanwell urges the AEMC to ensure the transition period to introduce 5 minute settlement allows adequate time to determine whether these new sources of caps are likely to develop.

As well as the issue of the cost of the new technologies, there is also the issue that selling a cap typically assumes the ability to continuously generate to cover the cap, sometimes for hours at a time. Energy Edge also points out that large scale batteries also don't address energy constraints. "*Ignoring economic issues large scale battery solutions can deliver energy [sic] constraint solutions quite quickly. However, they do not address energy constraint issues and in the short to medium term it is expected that they will only alleviate a small portion of the estimated reduction in supply of caps, and either directly or indirectly there will be cost consequences for the consumer.*"[34]

3.4 Impact on retail market competition

Stanwell suggests the AEMC consider the impact the rule change will have on retail market competition. The reduced supply of caps is likely to particularly adversely affect small, non-vertically integrated retailers. The AEMC appear to be aware of this issue *"The issue.. is the effect on, particularly, second-tier retailers and their ability to get themselves set on the wholesale side so they can compete on the retail side, with the consequential effect on industry structure and retail competition."*[35]

4 Incentivising efficient behaviour

The central rationale for the rule change proposal must be to create more efficient behavioural decisions through sharper financial incentives. This is reflected in the static analysis of historical outcomes undertaken by the AEMC and Russ Skelton and Associates, both of which found that generators would receive in the order of 0.1% more revenue – and customers would pay 0.1% more – under 5 minute settlement.

In order for there to be long term benefit to consumers, the proposed rule change must incentivise more efficient behaviours not just changed behaviours, and so it is important that modelling accounts correctly for market design (both existing and proposed).

It is Stanwell's understanding that the rule change proposal will not change the function of NEMDE. NEMDE currently maximises trading value over a single dispatch interval based on the state of the market at the start of that interval, the visible constraints on the system and scheduled participants' offers.

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[31] Page iii, AEMC 5 minute settlement Directions Paper, April 2017
[32] AEMO, RECOMMENDED TECHNICAL STANDARDS FOR GENERATOR LICENSING IN SOUTH AUSTRALIA: ADVICE TO ESCOSA, 31 March 2017
[33] Page iii, AEMC 5 minute settlement Directions Paper, April 2017
[34] Page 86, Energy Edge, Effect of 5 Minute Settlement on the Financial Market, March 2017
[35] Page 32, Transcript of AEMC 5 minute settlement public forum, May 2017

4.1 Pay for energy not pay for target

For each Dispatch Interval, the National Electricity Market Dispatch Engine (NEMDE) determines a regional reference price for all generation and load and dispatch targets for scheduled generation and load. The vast majority of load is non-scheduled and is assumed to be price inelastic. It is therefore the role of scheduled generation to change to meet the forecast load.

Because there are circa 14 million meters in the NEM, each of which represents the sum of demand generated by multiple decisions and processes behind that meter, demand forecasting is an inexact science at the best of times. However over a large sample set and small forecast window – such as a 5 minute dispatch interval – demand resembles a “random walk” which can be approximated by a linear forecast.

Generation dispatched to meet this demand should also resemble a random walk which can be approximated by a linear forecast in order to minimise the imbalances which must be managed through regulating Frequency Control Ancillary Services (FCAS) or free control system response[36]. Much of the modelling presented to date in this rule change process has been based on “pay for target”, or instantaneous response, rather than the “pay for energy” or linear response used by AEMO for settlement. This is problematic because it affects the analysis both qualitatively and quantitatively.

Taking the example from pages 19-20 of the directions paper, the rapid response generator increases generation in dispatch interval one, maintains output through dispatch interval two and decreases output in response to the lower priced dispatch interval three. The Commission states that the generator would receive $400/MWh under 30 minute settlement but $600/MWh under 5 minute settlement – “*under five minute settlement the price at which a generator is dispatched would be equal to the actual settlement value they receive and they would receive no less than their bid price.*”[37]

However under the actual “pay for energy” approach used by AEMO this is incorrect. The correct result is that the generator would receive $400/MWh under 30 minute settlement but $525/MWh under 5 minute settlement. This is 12.5% less than claimed by the AEMC. The calculations are illustrated in Table 2 below.

		Rapid response generator			**fast response generator**		
Period	Price ($/MWh	Target (MW)	Energy (MWh)	DI Revenue ($)	Target (MW)	Energy (MWh)	DI Revenue ($)
Initial state		0			0		
DI1	$600.00	30	1.25	$750.00	0	-	$0.00
DI2	$600.00	30	2.50	$1,500.00	0	-	$0.00
DI3	$300.00	0	1.25	$375.00	30	1.25	$375.00
DI4	$300.00	0	-	$0.00	30	2.50	$750.00
DI5	$300.00	0	-	$0.00	30	2.50	$750.00
DI6	$300.00	0	-	$0.00	30	2.50	$750.00
DI7-12	$50.00	0	-	$0.00	0	1.25	$62.50
30 minute settlement							
main TI	$400.00		5.00	$2,000.00		8.75	$3,500.00
trailing TI	$50.00		-	$0.00		1.25	$62.50
			5.00	$2,000.00		10.00	$3,562.50
average revenue ($/MWh)				$400.00			$356.25
5 minute settlement							
				$2,625.00			$2,687.50
average revenue ($/MWh)				$525.00			$268.75

Table 2: “Pay for energy” calculations for AEMC’s example on page 19-20 of directions paper

36 Such as governors on synchronous generators

37 Directions paper, page 20.

Qualitatively, the conclusion in the directions paper example – that under 5 minute settlement generators would always be paid at least their bid price - is changed, calling into question whether the proposal addresses this supposed shortcoming of the current market design. Quantitatively, pay for target exaggerates the difference between the settlement models – in the example the revenue to the rapid response generator under 5 minute settlement increases 31% using pay for energy but 50% using pay for target. While there are still gross benefits to the rapid response generator the difference may be material to a net benefits test such as is being undertaken by the Commission.

Some participants may argue that because certain technology can respond immediately it is appropriate to model its revenue as such, however this ignores the externalities caused by such a response. The additional revenue capable of being gained through instantaneous response is a transfer payment from one provider to another, not a saving to consumers, because the faster response is not meeting a change in demand but imposing an offsetting change on another generator. Ultimately such a transfer payment is only obtainable while there is enough generation capable of providing the offsetting response, and requires those generators to receive inefficiently low payments. Additionally, as volumes on non-linear responses increased FCAS procurement volumes will need to be increased and this cost is recovered from all market participants under current market design.

Stanwell considers that including such distortions in modelled benefits may lead to a poorly constructed case for implementation, ultimately coming at a cost to consumers.

4.2 Modelling only the difference between future states

It is important that the modelled benefits of the proposed rule change reflect the difference between two future states with different settlement periods rather than the difference between the current state and a future state with 5 minute settlement.

The Commission appears aware of the likelihood that the future state under the current rules will be significantly different to current market conditions.

> "*The Commission therefore considers that there are ample resources currently in the NEM, and new investments that will occur irrespective of the outcome of this rule change, that can physically respond to five minute prices.*"[38]
>
> "*As energy storage costs decline, the Commission expects that there will be significant investment in behind the meter storage irrespective of whether five minute settlement is implemented.*"[39] and
>
> "*The Commission expects that five minute settlement would lead to marginal changes in investment decisions.*"[40]

However, only backward looking static analysis has been provided to date. That is, analysis based on historic market outcomes where the most likely near term rapid response investment – batteries – are not considered. The qualitative commentary on page 70 of the directions paper needs to be explored to determine whether additional investment would occur in rapid responsive plant, or whether the self cannibalising nature of investment in rapid response generation would render the proposed price signal ineffective.

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[38] Directions paper, page 57
[39] Directions paper, page 69
[40] Directions paper, page 71

4.3 Compliance with dispatch instructions

The directions paper makes a number of references to the incentives on generation to respond to dispatch signals being stronger under 5 minute settlement than under 30 minute settlement.

> "*Finally, flexible generation technologies able to respond to the higher price will not get the full reward for this capability. It may mean they choose not to operate even though the price is signalling that it would be physically valued by the power system.*"[41]

This concern must relate to the issues of scheduling (Section 2.1) and the formulation of offers rather than incentives on scheduled plant to follow dispatch instructions. In the NEM, compliance with dispatch instructions is managed through an explicit Rules obligation. In May 2016 the AEMC determined to retain the existing arrangements rather than alter them as requested by Snowy Hydro.

> "*Clause 4.9.8(a) of the National Electricity Rules (NER) imposes a strict obligation on market participants to comply with a dispatch instruction unless to do so would, in that participant's reasonable opinion, be a hazard to public safety or materially risk damaging equipment."* and

> *"Given that the central dispatch process, and the dispatch instructions it produces, maximises the value of spot market trading, it is critical that market participants follow these instructions."*[42]

At the time that decision was made, the AER had "issued four infringement notices and instituted one legal proceeding"[43] in relation to this obligation. In the 11 months since the determination the AER has issued six (6) additional infringement notices, obtained at least two undertakings and issued three (3) infringement notices in relation to the related clause 4.9.8(b)[44].

Stanwell considers that these obligations and regulator actions confirm that compliance with dispatch instructions will not be materially affected by a change to the settlement period. As discussed in Section 2 of this submission, Stanwell encourages the Commission to ensure that there are sufficient pre conditions in place to enable the benefits of the proposed 5 minute rule change to be realised before changing the market design.

4.4 Potential for undesirable behaviour to emerge

SunMetals' rule change proposal aims to reduce what it considers to be undesirable behaviour and address barriers to entry.

> "*Sun Metals submits that the mismatch between the current dispatch and financial settlement intervals leads to inefficiencies in the operation and generation mix of the market. Specifically, this aspect of the market design:*
>
> • *accentuates strategic late rebidding, where generators have been observed to withdraw generation capacity in order to influence price outcomes*
>
> • *impedes market entry for fast response generation and demand side response.*" [45]

Sharpening price signals naturally sharpens the incentives for behaviour which maximises benefit to individual participants at the expense of others. While SunMetals propose 5 minute settlements to discourage perceived "late strategic bidding" which increases prices late in the Trading Interval and the Commission intend 5 minute settlement to remove the incentive to "pile in" and decrease price

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[41] Directions paper, page 18
[42] AEMC 2016, Compliance with dispatch instructions, Final Rule Determination, 5 May 2016, Sydney, pages i and ii.
[43] AEMC 2016, Compliance with dispatch instructions, Final Rule Determination, 5 May 2016, Sydney, page iv
[44] Two (2) infringement notices issued to each of ERM Power (11 May 2016), CS Energy (4 July 2016) and Energy Australia (13 January 2017).
Undertakings from CS Energy (public) and ERM Power (private).
Clause 4.9.8(b) infringement notices to CS Energy (4 July 2016 x 2) and AGl Hydro (13 January 2017)
[45] Directions Paper, page 2

following a high price early in the Trading Interval, it is unlikely that these will be the only changes in behaviour.

Other behavioural changes which may occur include:

1. Increased incentive to be non-scheduled and respond instantly rather than linearly, both of which create value transfers but are unlikely to lower overall costs (Sections 2.1 and 4.1)
2. Boundary issues as identified in the IES submissions to this rule change
3. Disincentive for existing peaking generators to sell – and defend - $300 cap contracts (Energy Edge report).

It is important that the Commission consider whether existing obligations and behavioural statements of conduct would be sufficient and appropriate to deal with undesirable behaviour which may arise following the rule change. In particular, most current obligations are applied only to registered and scheduled participants. These participants are beginning to represent a smaller proportion of the market than has historically been the case.

4.5 Retaining an incentive to respond over longer periods

While the directions paper focusses on the ability of participants to respond to short duration price events there is little account given to whether there should remain an incentive for slower responses which may lower prices over longer periods.

The current Fast Start Inflexibility Profile (FSIP) arrangements provide a mechanism to provide start signals to plant which cannot transition from rest to stable operation within a single dispatch interval in order to allow NEMDE to include their capability in future dispatch intervals when it attempts to solve them.

In the example on pages 19-20 of the directions paper, the “fast response generator” receives a commitment target in the first dispatch interval with a zero MW target. The presence of the FSIP prevents NEMDE from giving the fast response generator a target which it cannot achieve in the first dispatch interval but recognises that the plant is offered at lower cost than the rapid response generator and is likely to be beneficial to the market over a longer duration – dispatch intervals 3-6 in the example. The generation provided by the fast response generator in these dispatch intervals lowers the wholesale price (to $300/MWh) from that which would otherwise occur and reduces the resource cost of these dispatch intervals.

If NEMDE does not account for the FSIP in dispatch interval 1 it cannot target the fast response generator up in dispatch interval 3 unless the generator has started the unit and rebid to reflect its capability. It is unclear whether such action would comply with the requirements to provide an indication of a generator’s genuine intent to the market at all times.

The current 30 minute Trading Interval aligns with the requirement that a fast start plant be able to achieve stable operation within 30 minutes[46] and this enables AEMO to include the fast start generators’ response in predispatch. While the FSIP arrangements could be retained under a five minute settled market, the continuation of AEMO’s ability to publish meaningful predispatch may be compromised depending on the legal drafting chosen (see Section 5.1).

It will be important to ensure that there are actionable and relevant incentives for generation responses longer than a dispatch interval under a 5 minute settled market.

[46] Rule 3.8.19 (e)(6) “The sum (T1 + T2) must be less than or equal to 30 minutes.”

5 Unresolved implementation questions

5.1 Legal drafting of the change

The Rules currently require a large number of actions to be undertaken for each Trading Interval, which is defined as being 30 minutes. The proposed change to 5 minute settlement could be legally implemented in a number of ways with different impacts on these required actions.

For example, redefining the Trading Interval within the Rules to be a five minute period would require consequential changes to bidding systems, predispatch and PASA development and publication, Marginal Loss Factors, forecast and recording of network constraints etc. Such alteration is likely to add to the cost and complexity discussed by AEMO and consultants to date.

Alternatively, the formulation of the Trading Interval Price and participant compensation could be altered in a similar manner to the FCAS markets where the payment amount for each half hour is calculated as the sum of amounts for each dispatch interval. This would require amendment to multiple Rules clauses[47] – but may avoid the redevelopment of multiple systems. However under this approach the Trading Interval Price would not reflect the cost or revenue to most participants, bringing into question its purpose.

Regardless of the approach chosen there appear to be a number of redrafting tasks to remove "hard coded" references to 30 minute trading intervals from the Rules. In addition to the multiple references to "*the 48 Trading Intervals in a Trading day*" there are crossed definitions such as "*AEMO must publish a half hourly pre-dispatch schedule*"[48] and "*The pre-dispatch process is to have a resolution of one trading interval and no analysis will be made of operations within the trading interval, other than to ensure that contingency capacity reserves are adequate as set out in Chapter 4.*"[49]

When Stanwell have previously raised the topic of such crossed definitions in Rule determinations, the AEMC's response has been "*The Commission notes that the issues raised by Stanwell do not relate to inconsistencies in drafting of the final rule but relate to existing clauses.*

…

Should Stanwell have concerns in relation to inconsistencies in existing drafting in the Rules, the Commission encourages Stanwell to lodge a rule change request specifying requested changes it considers may be necessary." [50]

Stanwell does not consider that this approach would be acceptable for the proposed rule change. Such a "tidy up" of the existing rules may be a rational precondition imposed by the Commission under the transition roadmap described in Section 2.4. Stanwell would welcome the Commission stating their position on such issues prior to making a rule change in this instance.

5.2 Consequential impacts

Under current Rules there are a number of obligations which refer to Trading Interval outcomes, such as the AER Price event reports and compensation to participants affected by an AEMO Direction. There does not appear to have been any consideration given as to whether these reports and thresholds would remain appropriate or meaningful under the proposed changes.

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[47] for example clauses 3.9.1 and 3.9.2 both define the Trading Interval Price as the time weighted average of dispatch interval prices occurring within the Trading Interval
[48] Rule 3.13.4(e)
[49] Rule 3.8.20(b)
[50] AEMC 2016, (Demand Response Mechanism and Ancillary Services Unbundling), Final Rule Determination, 24 November 2016, Sydney, p156-157.

5.3 Impact on volatility

The directions paper notes that since the *National Electricity Amendment (Bidding in Good Faith) Rule 2015 No. 13* came into effect high prices have become relatively more prevalent in the first dispatch interval of a Trading Interval. While no quantification has been attempted, this phenomenon seems likely to be related to "boundary issues" with generation offers being required on a Trading Interval basis. This issue was discussed in the IES submissions.

Depending on whether bidding granularity is changed to 5 minute resolution (see Section 5.1 **Error! Reference source not found.**) this phenomenon may or may not change. That is, under 30 minute bidding the first dispatch interval is likely to remain more prone to large price swings than later dispatch intervals despite there being no incentive for distortions through averaging. Under 5 minute bidding, every dispatch interval may be affected by such boundary issues.

This is contrary to the commentary provided by the Commission with its release of the directions paper

> "*The Commission also notes that moving to five minute settlement is likely to lead to changes in bidding behaviour, which means historical patterns of five minute dispatch prices may not be a good guide for the future. For example, five minute settlement may lead to less volatility than displayed in the current five minute dispatch prices, with fewer and lower price spikes, and therefore the revenues for fast response generation technologies may be less than expected.*"[51]

Volatility may also arise through the impact of non-scheduled price responsive generators making large, frequent changes to their output. This was the "artificial price swings" effect described in Section 2.1.

Stanwell encourages the Commission to provide more detailed analysis on the likely changes in volatility under its proposed More Preferable Rule Change.

5.4 Comparison to international markets

The Directions paper references international actions in relation to market design as supporting the proposed rule change.

"*The benefits of aligning dispatch and settlement have been acknowledged by a range of international energy market authorities. For example, in a few overseas markets where dispatch and settlement are not aligned – some US markets, New Zealand and Alberta – regulators and market bodies are either in the process of aligning or recognise the merit in doing so. For example:*

- *the United States Federal Energy Regulatory Commission (FERC) in September 2016 ruled that all system operators under its jurisdiction must settle energy in their real-time markets at the same interval that those markets are dispatched (i.e. five minute settlement)[44]*
- *the New Zealand Electricity Authority has noted that aligned dispatch and settlement interval would be the ideal market design[45]*
- *aligning dispatch and settlement intervals has also been discussed by the Alberta Electric System Operator.[46]*"[52]

While the FERC order is clearly to align dispatch and settlement intervals it is notable that it both allows overlapping markets to have different timeframes[53] and addresses incentives to comply with dispatch instructions and reduce "uplift payments", none of which are relevant considerations for the

[51] AEMC media statement, Fast response energy – directions paper for five minute settlement, 11 April 2017.
[52] Directions paper, page 29
[53] UNITED STATES OF AMERICA FEDERAL ENERGY REGULATORY COMMISSION, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,*(Issued June 16, 2016), page 43.

NEM. The NEM has consistent timeframes across the market, strict compliance with dispatch obligations and does not have “uplift payments”.

The New Zealand Electricity Authority has proposed changing it’s market structure *to* a real time 5/30 design. The full text of the section referenced by the AEMC is

“*3.2.2 In theory, the ideal approach would be to align the trading period interval with the intervals used for dispatch and pricing. Doing this would make prices both actionable and more efficient. However, shortening the current 30-minute trading period would require extensive changes to settlement systems and processes affecting everyone in the wholesale and retail market. Given the likely substantial cost to implement such changes, the scope of the investigation and options did not include changing the length of the trading period.* ”

The “discussions” in Alberta occurred in 2005 and market design has not changed since. Alberta uses one minute dispatch and 60 minute settlement.

Doing something because others are doing it is a poor rationale for a major change. To the extent that international experience is incorporated into the Commissions decision making, Stanwell considers that it should inform *both* the incentive for alignment and the ultimate destination of that realignment. To date the Commission appears to have accepted 5 minute resolution as a given. There has been no explanation as to why alternatives – such as one minute or thirty minutes – would be less efficient, or contribute less to the NEO.