Seed Advisory

Five Minute Settlement: Threshold Conditions

Australian Energy Council: Final Report

1 September 2017

Contents

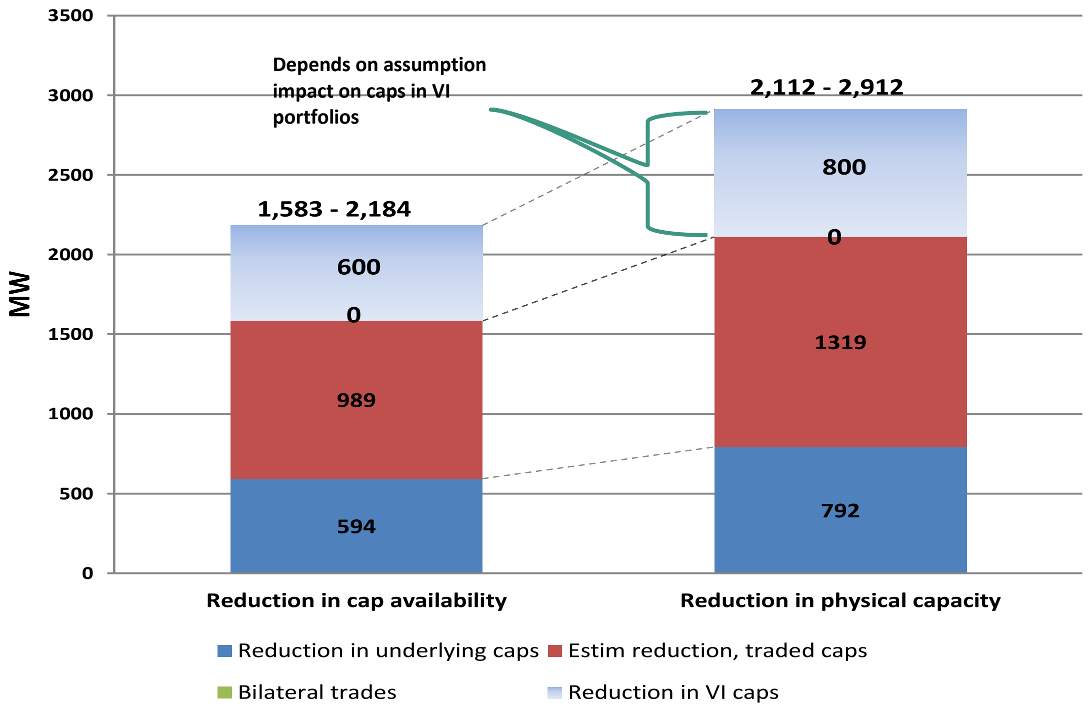
1. Executive Summary

The Australian Energy Council (the Energy Council) has proposed that the introduction of five minute settlement should only proceed if certain threshold conditions are met, including most significantly that there is sufficient fast-start scheduled supply (or equivalently firm and flexible demand response) existing to mitigate the risks of Open Cycle Gas Turbine (OCGT) withdrawal. In its absence, the Energy Council's second condition, sufficient contract market liquidity, cannot be met.

Our analysis finds:

- The potential reduction in caps currently provided for the management of retailers' risk as a result of exiting peaking generator capacity is materially larger than the estimate prepared for the Australian Energy Market Commission. We estimate an overall reduction in total traded caps of just under 1,600 MW.
  - This would reduce total traded cap market liquidity by around 23 percent in the mainland jurisdictions of the NEM (Section 3.1 and Appendix B).
  - This estimate does not include the reduction in caps provided within vertically integrated portfolios, which could reduce cap capacity by up to a further 600 MW (Section 3.1 and Appendix B). This potential reduction was not included in the prior analysis.
- If the affected generation capacity was to withdraw from the market, available peak capacity could be reduced by between 2,100 and 2,900 MW, based on our extension of Energy Edge's approach (see Section 3.1.2 and Figure 1.1).
- Withdrawal of peaking generators would result in a corresponding reduction in energy provided to the wholesale market, including during high demand periods (Section 3.1.3 and Appendix B).
- The potential negative impact on retail competition is also larger than estimates prepared for the AEMC, significant as they were.
  - The first round impacts can be predicted to be the largest on smaller retailers without the capacity – financial or a sufficiently large customer base – to finance the construction of their own internal hedges. South Australian retailers would also be materially affected, because the existing level of liquidity in financial products is so low that any further reduction in liquidity could be expected to have a material effect on market competitiveness.
  - In the absence of the conditions identified by the Energy Council the second round effects are likely to be higher prices, particularly experienced by residential and weather sensitive small commercial and industrial customers, as the price of cap contracts increases and competition in both the cap market and more generally is reduced.

Figure 1.1 Reductions in cap availability and corresponding capacity impacts, NEM mainland regions, estim MW



- Of the AEMC's candidates for near term replacements to exiting OCGT and other generation, more flexible gas-fired generators (aero derivative engines of the type to be installed in South Australia) are the only candidate capable of providing replacement capacity over a three year transition period, assuming investors are willing to underwrite the investment (Section 4). Significant additional investment would be required.
  - On a one for one basis, replacement costs could be expected to be $600 million or more (see Section 4.1.1).
  - Cap prices could be expected to increase for two reasons: the new peaking generation configuration will bear more risk in defending sold caps than under current 30 minute settlement; and, since on a MW for MW basis providing caps will be dearer, investors will want to recover their additional capital.
- Some combination of rapidly cycling and larger storage batteries could, in theory, replace exiting peaking generation capacity and some energy over a three year transition period. In practice, however, batteries are unlikely to be installed during the proposed transition period without significant subsidies (Section 4.1.3).
- More automated demand response and behind the meter aggregation are, at best, immature technologies. The extent to which they are capable of replacing exiting peaking generation is unknown (Section 4.1.2 and 4.1.5).

2. Our approach

2.1. Background

Under the change to the National Electricity Rules proposed by Sun Metals, which the Australian Energy Market Commission (AEMC) has indicated it is inclined to accept, the National Electricity Market (NEM) settlement interval would be reduced from 30 minutes to five minutes. Among others, the Australian Energy Council (the Energy Council) has suggested that the rule change should only proceed if certain threshold conditions are met.

The Energy Council's conditions that would need to be met include the following:

- sufficient fast-start scheduled supply (or equivalently firm and flexible demand response) existing to mitigate the risks of Open Cycle Gas Turbine (OCGT) withdrawal
- sufficient contract market liquidity in place to act as a buffer against the risk of a contraction in liquidity as market participants adjust to the new rules
- signs that metering competition is delivering greater numbers of Type 5 meters
- adequate IT system readiness and budget for implementing the necessary changes.

Of the Energy Council's conditions, this report focusses on the *prior* and *most significant condition,* that relating to the entry of sufficient fast-start scheduled supply or equivalently firm and flexible demand response. In its absence, the second condition, sufficient contract market liquidity, cannot be met.

We have focused on the risks to the markets – physical, financial and retail – of the assumption that there will be rapid entry of sufficiently large and price competitive substitutes for OCGT and other generator exits from the market in the event of the introduction of five minute settlement.

2.1.1. Impacts on the supply of caps, and related impacts on generation

As a first step, in Appendix B we look at estimates of the size of the likely impact on the total supply of caps, starting with Energy Edge's report for the AEMC looking at the impacts on *underlying caps*[1] and extending that analysis to *total traded caps* and to *caps provided within vertically integrated portfolios.* We also consider estimates provided in submissions to the AEMC on the expected impact of the changes on specific market participant's own generation and the market-wide impacts of the possible Rule Change.

Our findings, detailed in Appendix B, are summarised in Section 3, which looks at the our estimate of the reduction in all caps provided to market participants, the associated impact on peaking capacity, the potential impact on energy and, briefly, the implications for retail competition and prices.

[1] Energy Edge, 2017

2.1.2. Peaker Replacement generation candidates

Having considered the range of estimates for the potential market exit, in Section 4 we consider in relation to each of the AEMC's nominated candidates for near term replacements to exiting peaking generation:

- the current status of the technologies the AEMC identified as the likely source of the replacement generation
- whether the proposed replacements offer *capacity, energy* or both and, if both, to what extent the replacements could be considered a like-for-like replacement
- the *market conditions* required for the *unsubsidised* entry of the required entrants
  - For example, the ESCRI SA paper trial found that batteries would require access to all identifiable income streams – arbitrage, derivative sales, network deferral and support benefits, demand response payments – and that, even in the presence of these income streams, would not be profitable[2]. To the extent that this remains the case, then the presence (or absence) of some of these income streams is an important element in considering the likelihood of entry.
- whether these conditions are likely to be realised in NEM markets in the short to medium term, based wherever possible on current proponents' proposals, announced network programs and other public domain information.
  - We have reviewed ARENA's and other government supported R&D and early stage commercialisation programs for related projects, and considered the scale, timing and focus of these projects as they relate to flexible generation technologies anticipated to provide a substitute for exits from the market.
- whether, given the results of our analysis, the assumption that the entry of sufficient fast-start scheduled supply or equivalently firm and flexible demand response will provide timely substitutes for exits from the market is reasonable within the AEMC's proposed transition period, or some longer timeframe.

2.1.3. What characteristics are required to replace exiting peaking generation?

Considering the nature of the risk management product supplied by peaking generators, and their contribution to spot price formation, we've used three criteria in evaluating the AEMC's suggested alternatives.

[2] *ESCRI SA: Energy Storage for Commercial Renewable Integration South Australia. An Emerging Renewables "Measure" Project with the Australian Renewable Energy Agency,* Milestone Reports

Through-year availability	To provide a replacement product on a like-for-like basis with a peaking generator, an alternative provider selling caps needs to be able to pay its counterparty the difference between spot market prices and $300/MWh when spot prices increase above $300/MWh during any hour of the year. In its analysis, Energy Edge converted a range of cap products to flat, annual caps, that is, cap cover provided for 8,760 hours/year for a standard 1 MW cap contract. We've adopted the same approach. An alternative provider able or willing only to provide a cap during, say, summer sunlight hours, or for the four hours of a battery's discharge is providing only a fraction of the product currently provided by a peaking generator under 30 minute settlement. In these circumstances, the provider could still earn a fee, although it would be less than the cap premium paid for flat annual caps because the risk mitigation characteristics of the product offered would be materially lower than a flat annual cap provides.
Persistence	We expect the alternative to be provided on a predictable basis from year to year. First, retailers require multi-year cover to hedge multi-year offers to customers. Secondly, given the timelines required under normal circumstances for generation construction and connection, it would be extremely risky to proceed on the basis of an alternative service that one or two years into the future was no longer available, because customer interest had waned, or a business providing demand response services had moved, or worse, closed.
Additionality	In very broad terms, there are two ways of ensuring that, as a cap provider you are earning sufficient to ensure that you can pay your counterparty as required under your contract when the price is higher than $300/MWh. First, you can behave like a baseload generator, participating in the market day and night. As Energy Edge's analysis shows, coal fired generation is remarkably good at defending caps because it is typically generating when price spikes occur. Alternatively, you can respond to pre-dispatch price forecasts, revise your bids and ensure that if the price spikes as expected, you will be dispatched and will either earn the funds required to pay your counterparty, or as a result of your dispatch, the price will fall below the trigger

price of $300/MWh and no payment will be required. Of course, if you're a non-scheduled generator, you could just switch on.

In evaluating the AEMC's suggested alternatives, our view is their operating mode is likely to be the second – rapid response to an emerging price signal. Operating during periods when high prices occur will earn generators random rewards. Operating to defend a sold cap, that is, to earn the money required to pay your counterparty or prevent a payment obligation arising, requires targeted market participation. Hence, the requirement for additionality.

Of course, even the best targeted strategy is unlikely to result in any individual generator being dispatched on 100 percent of occasions when the price is above $300/MWh. Hence, generators use leverage (committing more capacity to the market in the event of a high price event than is strictly required to match caps sold) and maintain reserve capacity (the use of N-1 approach) to meet their obligations for caps sold. Applying these methods to managing the risks of selling caps could result in a requirement for multiples of the capacity displaced to provide similar risk management products, with a corresponding effect on the cost of replacement.

2.1.4. Where to from here?

Finally, we suggest a range of issues that need to be addressed by flexible generation and demand management technologies before concluding the services provided are substitutes for OCGT and other market exits. We propose ways in which the AEMC could ensure that current research programs are leveraged to provide the information necessary for the AEMC's future assessment of the market conditions for flexible generation and demand management technologies, and the likely supply of cap substitutes by these new entrants.

3. Implementing Five Minute Settlement: Effects on the caps market

3.1. Calculating the effects on caps available

In this section, we look at estimates of the size of the likely impact on the supply of caps, starting with Energy Edge's report, and consider also extensions and additions to those estimates taking into account our own review of Energy Edge's approach and submissions to the AEMC on the expected impact of the changes on specific market participant's own generation and the market-wide impacts of the possible Rule Change. The details of our approach and the basis for our estimates are given in Appendix B.

3.1.1. Reductions in caps sold: extending Energy Edge's estimates

Energy Edge's finding that "across the market approximately 625 MW of flat cap equivalent (23% of underlying cap volume) is likely to be withdrawn from the market, impacting retailers' ability to manage their financial market price and volume risk" represents the lower end of the estimated effects of the proposed Rule Change, considering Energy Edge's own approach. We estimate the potential impact on available caps – traded and in vertically integrated portfolios – at between 1,600 and 2,200 MW flat cap equivalent (Figure 3.1).

Figure 3.1 Extensions and adjustments to Energy Edge's estimate: Impact on all caps, by category and region, estimated MW

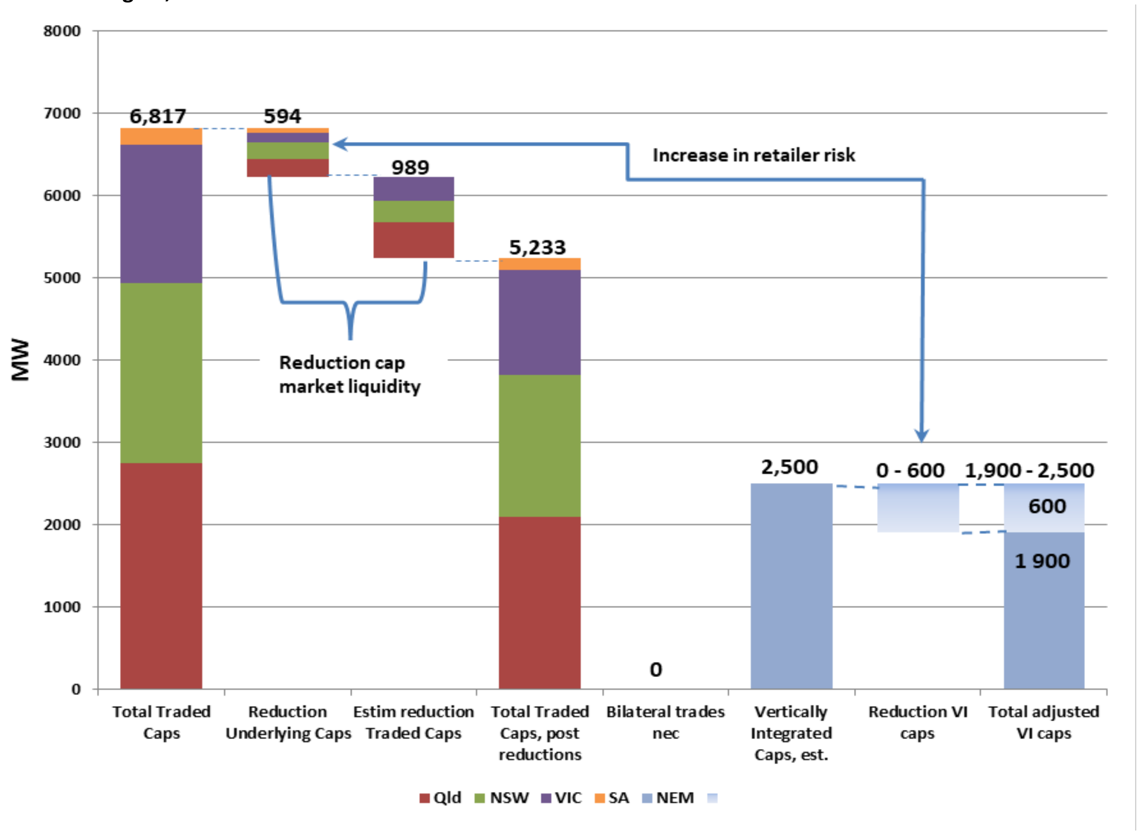
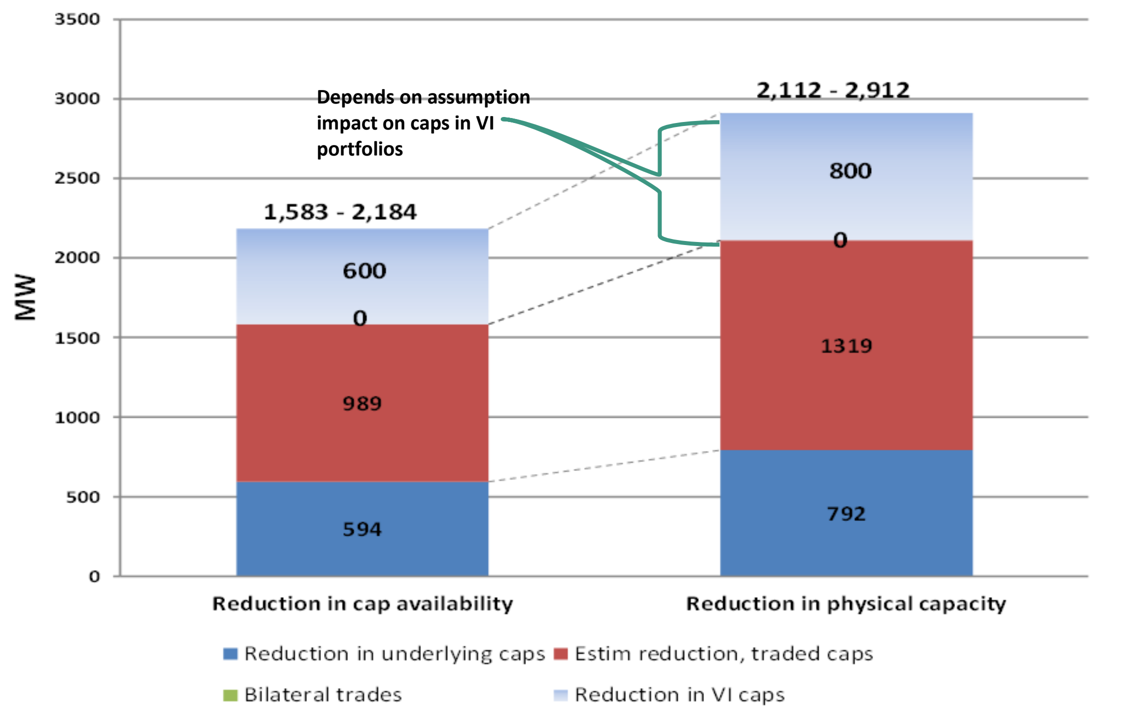


Figure 3.1 shows the individual extensions and additions to Energy Edge's approach considered in our work and the size of the corresponding addition, if any, we have proposed. Our results suggest that considering only underlying caps, Energy Edge has materially understated the potential impact on cap market liquidity, and has also understated the impact of the proposed Rule Change on retailers' ability to hedge their load by omitting any impact on vertically integrated entities' internal hedge capability.

3.1.2. Impact on peak capacity: Estimated generator capacity affected

Typically cap providers restrict cap sales to some proportion of their theoretical capacity to mitigate the risk of unexpected unit failure and to allow better coverage of the sold caps portfolio in the spot market through leverage. Applying an N-1 ratio of 0.75:1 to Energy Edge's calculations, and assuming that a withdrawal from the caps market results in a unacceptable reduction in generator income, then this would imply a withdrawal of between 2,100 and 2,900 MW generation capacity from the physical market following the withdrawal from the caps market (Figure 3.2).

Figure 3.2 Reductions in cap availability and corresponding capacity impacts, NEM mainland regions, estim MW



The N-1 ratio applied in this calculation may be too low given the higher risks of dispatch (equivalent to the lower effectiveness identified by Energy Edge) under 5 minute settlement: generators remaining in the caps market may apply a higher ratio of physical capacity to financial commitments to manage their risks.

3.1.3. Impact on energy

The AEMC has proposed as a hypothesis that price spikes are evidence of a trend, likely increasing, of greater transitory influences on demand or, alternatively, supply. Alternatively, but not discussed by the AEMC, price spikes may be the result of participant incentives arising from interactions of the current settlement period, portfolio structures and generator physical characteristics. The explanation for observed short duration price spikes is important.

- If price spikes are the result of transitory demand (supply) spikes, the effect on energy is likely to be very low, and the absence of any material consideration of the issue is appropriate.
  - In this report, we've used *capacity* to describe the required service and, reflecting the transitory nature of the requirement, have also described the service required as "seconds to minutes".[3]
  - "Seconds to minutes" is a useful way of thinking about frequency regulation and FCAS services that demand response and behind the meter aggregated resources may be well placed to provide without any observed impact on the value of energy to a business, or household comfort. Demand response and behind the meter aggregated resources may not be able or households and businesses willing to provide services for "hours to days".
  - However, some services provided by peaking generators fall into the "hours to days" class (see below).

- Price spikes tend not to be clustered, but observing this is not equivalent to demonstrating the proposition that the underlying cause of the spikes is transitory, and the energy implications are negligible. If generators are dispatched for longer than a single or small number of clustered dispatch intervals in response to an initial price spike, then the absence of recurrent price spikes or persistent high prices may be a result of the interactions between the current settlement period, generators' risk management practices and portfolio bidding; it says nothing necessarily about the duration of any associated demand (or supply) spike.
  - Peaking generators provide both *capacity* and *energy*: peaking generators are dispatched for longer than a single or small number of clustered dispatch intervals, particularly when the capacity dispatched is higher than average (see Appendix B; Figure B. 6).
  - Recognising the contribution of peaking generators to energy, we've used *energy* to describe the required service and, reflecting the duration of service required, have also describe the service required as "hours to days".

- In assessing the implications of the proposed Rule Change it's important to understand whether the proposed replacements offer *capacity, energy* or *both* and, if both, to what extent the replacements could be considered a like-for-like replacement.
  - In the context of providing caps, capacity has some very specific dimensions. Unlike Critical Peak Products for example, caps offer 24/7 protection against prices above $300/MWh. A demand response provider willing to reduce its demand on 10 occasions a year given 10 minutes notice is not a one-for-one substitute for an OCGT generator paying out on any of the 8,760 hours in a typical year when the price exceeds $300/MWh.

[3] The distinction between "seconds to minutes" and "hours to days" has been taken from the Rocky Mountain Institute's discussion of technology and grid stability in https://rmi.org/news/grid-needs-symphony-not-shouting-match/, June 12, 2017. RMI includes a third category, "weeks to months" in its schema of grid integration.

- The dimensions we've used in assessing the current state of the potential alternatives are: through-year availability; persistence; and additionality. If it's not additional, then we're double counting: the operation of the load will have already been effectively considered in energy and capacity projections, based on prior performance (see Section 2.1.3. for further discussion).

In Section 4 we have considered which of the AEMC's suggested alternatives provide capacity, energy or both, and in what quantity. These dimensions are important issues to consider in assessing whether (and to what extent) the suggested alternatives are a substitute for current generation potentially affected by the proposed Rule Change, using the tests we propose.

3.2. Implications of potential financial and physical market impacts for retail competition

Our extensions and additions to Energy Edge's estimate of the impact of the proposed Rule Change on underlying caps mean the potential negative impact on retail competition is larger than Energy Edge's estimate, significant as it was. Total cap market liquidity is reduced: the 23 percent reduction in total traded cap market liquidity we calculate reduces overall cap market liquidity as well as reducing the availability of caps taken to maturity (underlying caps).

The first round impacts can be predicted to be the largest on smaller retailers without the capacity – financial or a sufficiently large customer base – to finance the construction of their own internal hedges. South Australian retailers are also materially impacted, because the existing level of liquidity in financial products is so low that any further reduction in liquidity could be expected to have a material effect on market competitiveness.

In the absence of the conditions identified by the Energy Council the second round effects are likely to be higher prices, particularly experienced by residential and weather sensitive small commercial and industrial customers, as the price of cap contracts increases and competition in both the cap market and more generally is reduced.

4. Introducing Five Minute Settlement: New market entrants

In this section, we consider the likelihood of the replacement technologies identified by the AEMC entering the market at the scale likely to be required over the three year time frame proposed by the AEMC, or even over a longer time frame.

Among the issues we consider are:

- the current status of the technologies the AEMC identified as the likely source of the replacement generation – in particular, whether or not the technologies participate in the NEM currently, and if so, at what scale.
  - Representation in the NEM is short hand for both the maturity of the technology and known registration and bidding procedures, known treatment under TUoS and DUoS regimes, treatment for FCAS where behind-the-meter or part of a portfolio and other issues, all of which have the potential to affect both operation and the economic case for uptake, as both previous paper trials and subsidised battery entrants to the NEM are identifying.
  - Pumped hydro energy storage is a known quantity, participating in the NEM and with a known set of obligations. Utility-scale batteries are materially less so, as the presentation and discussion at AEMO's recent Battery Forum indicated.
- whether the proposed replacements offer *capacity, energy* or both and, if both, to what extent the replacements could be considered a like-for-like replacement
- where the nominated technologies do not participate in the NEM, the *market conditions* required for the *unsubsidised* entry of the required entrants
- whether these conditions are likely to be realised in NEM markets in the short to medium term, based wherever possible on current proponents' proposals, announced network programs and other public domain information.
- whether, given the results of our analysis, the assumption that the entry of sufficient fast-start scheduled supply or equivalently firm and flexible demand response will provide timely substitutes for exits from the market is reasonable within the AEMC's proposed transition period, or some longer timeframe.

We conclude that over a three year transition period more flexible gas-fired generators (aero derivative engines of the type to be installed in South Australia, for example) are the most prospective candidates to supplement or replace exiting peaking generation, assuming investors are willing to underwrite the investment. Table 4.1 summarises our views on the ability of the AEMC's candidates for near term replacements to exiting OCGT and other generation to replace exiting generators over a three year transition period.

Table 4.1 Candidates for near-term replacement, exiting cap providers: summary characteristics

Nominated near term replacements	Represented in the NEM? (1)	Installed in volume in 3 years?	Incremental capital requirements	Subsidy required?	Cap equivalent capacity?	Energy?
Aero derivative engines, etc.	Yes	Yes	High	No; anticipate cap prices increasing	Yes	Unclear; class adopted in SA, for example, provides capacity rather than energy.
More automated demand response	Yes, but providing different services	?	? (2)	?	Unlikely: not clear that provide through-year or persistent responses	No
Utility-scale batteries	By summer 2018, but key issues remain to be resolved	Yes	High	Yes	Not simultaneously: different types of batteries required for each service	
Pumped Hydro Energy Storage	Yes	No	High	?	Yes	Yes
Behind-the-meter aggregation	No	No	? (2)	?	Unlikely: not clear that provide through-year or persistent responses	No

(1) Represented in the NEM is short hand for both the maturity of the technology and known registration and bidding procedures, exposure to TUoS and DUoS, treatment for FCAS where BTM or part of a portfolio, etc., all of which have the potential to affect both operation and the economic case for uptake, as both previous paper trials and subsidised battery entrants to the NEM are identifying.

(2) The required capital investment is incurred by businesses or households not typically included in thinking about capital intensity or capital productivity in the energy sector. However, to the extent these sectors are providing cap replacement services, their capital expenditures should be considered, and they're not necessarily negligible. Some estimates suggest, for example, that the effective cost of behind the meter generation, storage and market services is significantly more than $1 million/MW, potentially more expensive than aero derivative engines.

On a one for one basis, just using Energy Edge's estimate of affected cap capacity, replacement costs could be expected to be $600 million or more, given a unit cost of for aero derivative engines similar to those adopted in South Australia of $1 million/MW plus. Our extended estimates would proportionally increase the cost of replacement, up to around $3 billion at our maximum affected capacity estimate. We expect some replacement, but rather than net new capacity, some loss of capacity. Cap prices could be expected to increase for two reasons: the new peaking generation configuration will bear more risk in defending sold caps than under current 30 minute settlement; and, since on a MW for MW basis providing caps will be dearer, investors will want to recover their additional capital.

Some combination of rapidly cycling and larger storage batteries could, in theory, replace exiting peaking generation capacity and some energy over a three year transition period. In practice, however, the economics of batteries require a range of income streams, most of which are absent, and, even if the income streams were present, it's unclear that batteries would be installed without significant subsidies.

More automated demand response and behind the meter aggregation are, at best, immature technologies. The ability of the technology to provide a material share of the services currently provided by cap providers, considering either capacity or capacity and energy, is currently unknown, and is unlikely to be known with any degree of certainty within a three year transition period. There are measures the AEMC could take to better inform itself about the critical features of these technologies and the likely near to medium term contribution they may make to the NEM.

4.1. What types of flexible new generation technologies are suggested new entrants?

Although not exhaustive given its technology neutral objective, the AEMC's candidates for near term replacements to exiting OCGT and other generation are:

- "More flexible unit choice and configuration of gas fired generation
- More automation of demand response activities, so that a faster response can be provided
- Investment in battery storage technologies, especially utility-scale storage
- Aggregation and control of behind the meter energy storage resources."[4]

In the first of these categories we've considered the aero derivative engines recently purchased by the South Australian government and their equivalent.[5]

We've included pumped hydro energy storage (PHES) as a sub-category under the discussion of storage. The AEMC's candidates (and the Directions Paper as a whole) omit PHES, although recent ARENA funded work suggests no shortage of potential

[4] AEMC, *Five Minute Settlement,* directions paper, April 2017, Sydney, p. 71

[5] https://www.premier.sa.gov.au/index.php/jay-weatherill-news-releases/7840-long-term-back-up-power-plant-to-be-delivered-before-summer The discussion at the Directions Paper hearing in May 2017 contested the assumption that it was either possible or efficient to alter the configuration of existing gas-fired generators; we've left this issue to the engineers and assumed that investment in new rapid response generation is the preferred engineering outcome.

sites [6] and the technology allows for both rapid response capacity and energy over longer periods of time, limited only by the capacity of the site.[7]

In the material that follows, we discuss each of the alternatives in turn. In each section:

- Where the technology currently participates in the NEM, we consider the extent of the current presence in the NEM.
- Alternatively, where the technology is emerging, we discuss the status of current Australian trials, their timing, and the relationship of current trials to the characteristics the technology would need to display to provide a replacement for exiting cap providers.
- We discuss the market conditions required to support the technology's unsubsidised entry
- We discuss the gaps in our information in relation to the performance of the technologies as alternatives to OCGT and other peaking generation and identify ways in which the AEMC might address information deficits where they exist.

4.1.1. More flexible unit choice, gas fired generation: aero derivative engines

This is the most prospective of all of the AEMC's candidates to replace exiting OCGT and other generators, assuming a three year transition.

The technology exists, although the marketing niche for the class chosen in South Australia is the provision of *capacity*, not *energy.*[8] In our view, its most likely role given five minute settlement would be as an extension to current generators with some rapid response capacity, plugging some of the gap between the response time of the existing generators and the shorter settlement period with a lower response time. There would be an increase in the capital intensity of the generation sector, but a decline in capital (and overall) productivity: similar services would be provided by a larger amount of capital.

As South Australia's current installation timeline illustrates, installation of the required capacity could easily occur over a three year transition period, given willing investors. South Australia's approach also makes it clear that, although access to gas is desirable, the potential to use a range of fuels including diesel (and the ability to substitute gas for diesel) means that no NEM mainland region would necessarily see a shortfall of cap capacity.

However, there are important questions relating to the scale of any take-up, and the related implications for cap prices. Working from the scant detail provided in the South Australian Government's announcements, the effective cost of a MW capacity is somewhat higher than $1 million/MW. At $1 million/MW, replacing Energy Edge's

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[6] https://www.dropbox.com/s/q5l03i9pcpxz3v1/170803%20PHES%20Atlas.pdf?dl=0

[7] Private communication, ANU Study author/Seed Advisory

[8] The class chosen by the South Australian government, for example, is marketed by GE as having "[t]he ability to go from cold iron to full power in just 10 minutes and the ability to start and stop in short, 15-minute cycles (several times per day if necessary) without impacting maintenance intervals mak[ing] GE's aero derivative gas turbines exceptionally adept at accommodating fluctuating demand ... GE's aero derivative gas turbines can be the first to respond to a peak power demand opportunity, without the costs of a spinning reserve." https://www.gepower.com/content/dam/gepower-pgdp/global/en_US/documents/product/aeroderivative-products-services-brochure.pdf

estimated 625 MW withdrawals requires an investment of more than $600 million, not taking into account South Australia's current commitment.[9] Substituting our higher estimates of affected capacity for Energy Edge's means the costs would be proportionally higher. At the outer limits of our estimate of affected capacity, a one-for-one replacement would require around $3 billion of new investment. Under current wholesale market conditions, new investment commitments on this scale must be considered extremely unlikely: the investment appetite to commit even $600 million plus to the generation sector may not exist.

As the expenditure required improves the responsiveness of a generator without increasing its capacity or energy, then some peaking generators materially affected by the proposed shift to five minute settlement will choose not to invest, either taking higher risks or prematurely exiting the caps market and, possibly, the market altogether, reducing both available capacity and energy.[10] Whether or not there are generator exits, cap prices will need to increase if investors are to recover their additional investments. Further, in the absence of a one-for-one investment, we'd expect cap market liquidity to fall and cap prices to increase.

4.1.2. Automated demand response activities

Of the existing demand response available in the NEM, submissions to the AEMC suggest that very little of that capability, whether or not automated, is currently capable of a response inside five minutes. The capacity and energy being offered into the market in demand response programs is already part of the NEM demand/supply balance. What's required if demand response is to provide a substitute for exiting peaking generators is additional demand response, either an increase to the commitment of existing demand response providers or an extension of demand response to wider groups of potential providers.

Oakley Greenwood's earlier study for the AEMC is the most robust publicly available evidence of the existing demand response capacity, and is not encouraging in contemplating the potential for demand response as a substitute for peaking generation.[11] Oakley Greenwood's study suggests:

- Relatively little of the retailers' demand response is capable of responding with five minutes notice, consistent with the observations made in the submission to the AEMC by the Major Energy Users.[12]
- The duration of demand response reported by specialist demand response providers ranged from a maximum of an hour for quick demand response from selected actions to up to 10 hours from interruptions to large loads and the operation of small scale generation. Using our classification, current programs

[9] South Australia's proposed use of the generators precludes their participation in the market other than to avert wide spread load shedding. While this policy remains, our approach is consistent with the South Australian Government's approach.

[10] Not necessarily only these generators. Investors concerned about uncertainty in the NEM and/or with concerns about the return on their investment may choose not to extend their exposure to the NEM in the absence of any surety that their investment will be profitably recouped.

[11] Oakley Greenwood, *Current Status of DR in the NEM: Interviews with Electricity Retailers and DR Specialist Providers,* June 2016

[12] http://aemc.gov.au/getattachment/5ede6701-090b-4601-9af8-d4d05bd7d129/Major-Energy-Users-%E2%80%93-received-23-May-2017.aspx

provide some, but not necessarily fast-response, capacity[13] and some energy, although both are subject to material limitations.
- The distribution of existing demand response by region suggests a higher proportion in Queensland and South Australia than in NSW or Victoria, although this may reflect the long standing persistence of higher prices and lower cap availability in these regions.

The submissions provide no material evidence that potential demand response is likely in the short to medium term to provide the required capacity or energy. Despite Enernoc's argument that "… the types of responses required to provide FCAS are not exactly the same as the type of responses required to be price-responsive in the energy market (i.e. the speed, duration, and frequency of the required demand response varies between the two services) but … the principle is the same …"[14], the types of responses required to provide FCAS services are very different from the types of responses required to provide capacity over a five minute interval either across the year or persistently, or energy for any duration. Responses suitable to provide FCAS services are unlikely to provide a one-for-one basis for replacement caps, even if coupled with longer duration capacity and energy from existing peaking generators.[15]

Enernoc is confident of its ability to get to triple digits, and argues the AEMC should not be focused on the 625 MW cap reduction. However, Enernoc's confidence is not a sufficient basis for assuming that *incremental capacity* and *energy* can be identified and will be a persistent presence in the market.

We've reviewed the activity currently being sponsored across Australia in demand response and other technologies that could replace exiting cap providers (Appendix C). None of the current projects identified immediately addresses the requirements of demand response under five minute settlement, specifically the requirements for through-year availability, persistence and delivery certainty. [16] Of the current projects listed in detail in Appendix C, the two most relevant projects are:

- The NSW Government/ARENA Pilot Demand Side Response Program which commenced in mid-2017 and is seeking to identify 60 to 70 MW demand response for extreme peak demand days and emergencies (that is, providing limited recourse capacity).
- The AEMO/ARENA Demand Response Pilot Program for which applications for the 2017 year are currently being reviewed. The program is looking for 100 MW to be used for up to 4 hours at a time on a maximum of 10 occasions (providing limited recourse capacity and concurrent energy).

[13] There's a subtle but important difference between being able to provide a response within five minutes and being able to respond with five minutes notice.
[14] http://aemc.gov.au/getattachment/a3894f93-1227-4fb5-b882-057762d678fc/EnerNOC-%E2%80%93-received-26-May-2017.aspx, p.5.
[15] You could patch together a larger diverse group of demand response providers each willing to provide, say, responses on 10 occasions a year to build through-year cover, but we'd expect you'd need a significant multiple in MWs signed to provide a one MW flat annual cap. Not knowing the required multiple is a key gap in assessing the readiness of demand response to replace caps.
[16] Over time, other projects intended to reduce or moderate the behaviours of hot water systems and air conditioning could reduce the need for cap contracts, but the current projects identified are not of a scale likely in the short to medium term to offset the loss of caps as a result of the introduction of five minute settlement.

However, these programs are looking for respondents capable of participating with 10 or 60 minutes notification: neither category appropriate for participating in demand response with a response time of less than five minutes to be used to back cap sales.

The current trials may provide some, largely indirect, insight into existing incremental availability of both capacity and energy from demand response, as well as a basis for estimating future growth prospects. Current projects could also provide some, again indirect, insight into the most prospective industries to provide the required highly flexible demand response capacity and energy, and the challenges and costs of extending the current demand response capability to the point where it is capable of providing a material contribution to capacity and energy under five minute settlement. Although the initial results of these programs – that is, what's the quantity and time to market for interested parties – should become available shortly, the questions the AEMC needs to address are through-year availability, persistence, delivery certainty and price, the data for which will become available over time. The AEMC should consider what is required for it to become a party to these programs and/or their detailed results to better inform its estimates of the potential contribution of demand response in replacing exiting cap providers.

4.1.3. Utility-scale Battery storage

By the end of summer 2018, assuming the Victorian Government's Energy Storage Initiative is successful, the NEM will have up to three utility-scale battery installations, the SA Government/Tesla project with 100 MW capacity and 129 MWh energy (just under an hour and a half's duration) primarily directed at network support services, and up to 40 MW capacity and 100 MWh energy (two and a half hours' duration) over two sites in Victoria. The batteries are large in absolute terms, and the only utility-scale projects in a longer list of battery trials and projects currently underway (see Appendix C). Both the SA and Victorian projects are subsidised, by the South Australian government and a combination of the Victorian Government and ARENA respectively, and their economic viability in the absence of these subsidies is unknown. In operating in the NEM, both projects will initially be operating under interim arrangements as AEMO considers the issues for its policies, procedures and systems of integrating batteries into dispatch.

However, the 2014-15 ESCRI SA project looking at energy storage in South Australia includes a number of insights that remain relevant to the assessment of utility-scale batteries as a substitute for exiting peaking generation.[17] Key findings relevant to this project include:

- In the absence of greater spot volatility and higher cap prices than were modelled at the time, the ability to monetise the potential to defer or augment transmission capital upgrades, and a rapid reduction in battery capital costs, even the smaller 10 MW, 15 MWh configuration in the last stages of the project was unprofitable.
  - Of a total cost of just over $25 million – capital expenditure and the net present value of operating expenses – the net present value of the battery over its 10 year life was negative $18.8 million. Taking into account tax, the

[17] *ESCRI SA: Energy Storage for Commercial Renewable Integration South Australia. An Emerging Renewables "Measure" Project with the Australian Renewable Energy Agency,* Milestone Reports

ARENA funding required for the battery to be installed would have been $14.8 million, or 60 per cent of the total cost.

- Early work on the project identified that capturing all the potential revenue streams theoretically available to a battery was critical to improving the economics of the installation, although even with all the potential revenues included in the business case, the battery remained unprofitable. Those revenue streams included Network Augmentation, Capital Deferral, Localised Frequency Support, Expected Unserved Energy reduction, constraint reductions (local and relating to both SA interconnectors), Grid Support Cost Reduction, Ancillary Services Support and avoided FCAS obligations.
  - We have reviewed the most recent Annual Planning Reports of mainland NEM region DNSPs and TNSPs. Of the 34 projects identified in current RIT-T and RIT-D programs, two projects identified batteries as among the solutions being considered. Three networks identified no projects in the RIT-T or RIT-D categories. In the short term, this suggests network support contributions cannot be regarded as a significant potential source of battery revenue.
  - Some of the network and market revenue streams included in the modelling are theoretical, rather than actual revenue streams at this point. The reduction in Expected Unserved Energy, for example, provides an economic benefit, but no commensurate financial benefit to the provider.
  - Eligibility parameters for participation in some NEM markets are still to be determined, although AEMO has proposed transitional arrangements, including for FCAS.[18] While AEMO is interested in pursuing proof-of-concept testing to explore the potential for batteries to provide fast frequency response (FFR) services, it has advised the market that considerable work will be necessary to assess suitable parameters for FFR specification(s) that could be applied more broadly in the NEM. Transitional arrangements may be trialed as part of the proof-of-concept testing.

- The modelling restricted the battery to one cycle or less a day to maintain its economic life at no less than 10 years and, as a result of this assumption and the limited energy provided by the battery reviewed (one and a half to a maximum of two hours), the cap effectiveness averaged around 44 percent on a look-back, 100 percent hindsight basis under 30 minute settlement. An assumption of 40 percent effectiveness was used in the financial model.
  - Under five minute settlement, subject to the same operating constraints cap effectiveness would have likely been reduced. In particular, batteries face very expensive trade-offs between the operating regime and battery life. In the battery chosen for the ESCRI paper trial, operating for one or less cycles a day for a maximum of two hours maximised battery life, but significantly limited responsiveness to high prices. Depending on the negotiations between the vendor and the buyer, operating to a different cycle could void the warranties.

[18] AEMO Industry Forum, *Interim Arrangements for Utility Scale Battery Technology*, July 2017; http://aemo.com.au/-/media/Files/Electricity/NEM/Participant_Information/New-Participants/Interim-arrangements-for-utility-scale-battery-technology.pdf

- A battery configured similarly to that in the ESCRI project would likely to be about as effective or less effective in defending sold caps as Energy Edge's estimates for OCGT generators under five minute settlement.
- Given this low level of effectiveness, Energy Edge expects existing generators to reduce their participation in the cap market, withdraw from providing caps altogether, and/or withdraw from the market as a whole. Given the other issues in profitable battery investment, should we expect battery investment (at a scale previously unknown) to happen?

- This finding highlights a further finding over the life of the study. Although there's a tendency to discuss batteries as if they belong to a "one size fits all" category, batteries designed to provide capacity on a high frequency basis (caps and FCAS type services), batteries designed to provide energy (storage and arbitrage), and batteries configured for other uses have different characteristics. Lazard's Levelized Cost of Storage Version 2.0 illustrates the issue.[19]
  - Batteries capable of providing both capacity and energy over a sustained period in a day ("Peaker Replacement", in Lazard's schema) are materially larger and more expensive, considered on $/MWh basis, than the battery category most suitable for providing capacity for five minutes or less ("Frequency Regulation").
  - Peaker Replacement batteries also have higher annual energy output, longer project lives and correspondingly larger lifetime output. Lithium-ion Peaker Replacement batteries are configured in the study as 100 MW capacity and 400 MWh energy (four hours discharge).However, Peaker Replacement batteries' preferred operating mode is one cycle a day; the smaller batteries suitable for FCAS services and meeting transitory demand peaks can cycle 4.8 times a day. Batteries classified as Frequency Regulation have a 10 MW capacity, and 5 MWh energy, that is, half hour discharge.
  - Using a $US/$A exchange rate of 1:0.75, Lazard estimates the unsubsidised lifetime levelized cost of lithium-ion batteries (cheapest in this category) in the frequency regulation class as $253/MWh, and lithium-ion Peaker Replacement batteries (among the cheapest in its category) at $380/MWh. Both of these costs compare unfavourably to AGL's recent published estimates of levelized costs for CCGT and OCGT plants, even taking into account AGL's allowance for high gas input costs, and imply that an increase in cap premia would be required.[20, 21] Using Lazard's low end estimate of the capital cost, the capital investment for one MW ranges from just under $0.9 million to $5.6 million, depending on whether you adopt the smaller Frequency Regulation battery or

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[19] *Lazard's Levelized Cost of Storage Version 2.0*, December 2016

[20] https://www.agl.com.au/-/media/DLS/About-AGL/Documents/Investor-Centre/170502-Macquarie-conference-presentation---A-future-of-storable-renewable-energy.pdf?la=en

[21] That cap premia needed to rise was also the conclusion of recent work by Dylan McConnell, *Value of Aligning Dispatch and Settlement*, Australian-German Climate and Energy College, Working Paper No. 4, 27 November 2016, relying on an earlier version of Lazard's work. It's unclear, however, from the paper, whether the estimated cap premia are high enough: although the paper appears to use a battery with similar characteristics to the Peaker Replacement class in Version 2.0 of Lazard's work, the number of cycles implied in defending sold caps appears to be inconsistent with the operating regime required to maximise the plant operating life.

the larger Peaker Replacement battery as the more appropriate solution. In isolation, neither is a suitable replacement for the capacity and energy provided by current peaking generators.

At a high level, a conclusion we could draw from what we currently know is that, within a three year transition period, absent a substantial and sustained increase in cap premia, batteries are unlikely to replace the cap market capacity requirements resulting from exiting cap providers: the economic model is unfavourable. Smaller, rapidly cycling batteries are incapable of providing a substitute for the energy supplied to the market by exiting peaking generators; larger Peaker Replacements' optimal dispatch is inconsistent with defending sold cap positions over sustained periods of time, or opportunistically outside the standard scheduled operations. Some combination of the two may be appropriate, but what combination?

These are testable propositions: the ESCRI-SA project provided ARENA with a financial model that would allow the AEMC to replicate the earlier modelling using current measures of price volatility and recent and projected cap premia to identify whether, and to what extent, batteries would continue to require network support payments, other sources of income and, possibly, subsidies to enter the NEM under five minute settlement. Further, working with AEMO, the AEMC could update assumptions about FCAS values and eligibility, TUoS and DUoS application, market fees and other issues which, although small in themselves, are significant given the current unprofitability of batteries when modelled.

4.1.4. Pumped Hydro Energy Storage

Currently there are 1,340 MW of pumped hydro energy storage in the NEM, and ARENA supported studies relating to four further projects in Queensland, South Australia and NSW (Appendix C), in addition to the Atlas of Pumped Hydro Energy Storage which recently published data on 5,800 potential off-river sites in South Australia, Queensland, Tasmania and the ACT and surrounding districts and anticipates identifying 10,000 sites Australia-wide.[22]

PHES is a potential replacement for the capacity and energy supplied by OCGT generation. Depending on the precise design, PHES is capable of response times as short as 30 seconds, but typically around 2 to 3 minutes on a par with the responsiveness of aero derivative gas turbines.[23] Potential generation is a function of size. Snowy 2.0, if it proceeds, has the capacity to store up to 360 GWh, and the atlas has identified several other sites in the regions already reviewed with storage capacity above 100 GWh.

As a replacement for peaking generators and the leading storage technology internationally, PHES is a strong candidate. Depending on the project, PHES is capable of providing a larger volume of storage and supplying energy over a longer period than Peaker Replacement batteries. However, over a three year transition period, with the possible exception of the Snowy 2.0 project, PHES is unlikely to substitute for exiting peaking generators.

[22] https://www.dropbox.com/s/q5l03i9pcpxz3v1/170803%20PHES%20Atlas.pdf?dl=0

[23] Correspondence, Seed Advisory and team lead, ANU Atlas of Pumped Hydro Energy Storage, August 2017

- Although with standardisation and replication construction times post-permitting might be as short as two to three years, permitting could easily take several years to be achieved.
- In Victoria, policy restricting the construction of new dams could prevent the uptake of PHES so that, even if PHES is the best substitute for exiting peaking generators the Victorian region may not be in a position to adopt the technology.
- Standardisation and replication have the potential to reduce the costs of construction. The Snowy 2.0 Feasibility Study is working with an estimated budget of $2 billion for construction, or $1 million/MW, similar to the costs of aero derivative engines, and potentially less than the estimated costs of Peaker Replacement batteries.

The relative merits of the technologies are difficult to assess in the absence of capital cost estimates and plant lives. Notwithstanding round trip efficiencies that may be lower for PHES than optimally managed industrial scale batteries, longer anticipated plant lives for PHES could result in a lower levelized cost of energy. The AEMC could consider what is required for it to become a party to ARENA's current PHES projects and/or their detailed results to better inform its view of the potential costs, particularly relative to aero derivative gas turbines and the possible timing of the construction of the specific developments being studied, as potential substitutes for exiting cap providers.

4.1.5. Aggregation and dispatch, behind the meter storage resources

Of the projects looking at aggregation and dispatch of behind the meter storage resources and Virtual Power Plants in Appendix C, the largest is the five year AGL Household Virtual Power Plant Project in South Australia, where AGL plans to install 1,000 centrally controlled batteries in South Australian homes and businesses. When the participants are signed and the batteries (and where necessary solar PV) installed, the virtual power plant will be capable of 5 MW output. Six months into the five year project, in June 2017, AGL had signed around 50 percent of the targeted customers.[24] The cost of the trial effectively is $25,000/participant. However, assuming target prices for similar PV and battery systems, the costs outside the trial are likely to be around $10,000/customer, or $2 million/MW.

The regulatory and market structures for behind the meter resource aggregation are unknown. The AGL and other trials are in their very early stages; there are no aggregated behind the meter resources bid into the NEM currently; and the policies, procedures and systems for integrating behind the meter resources into dispatch are unknown. COAG is currently considering issues relating to competition and licensing of these and other services.

What conditions need to be met for these resources to play a role in replacing exiting peaking generators? Assuming that the regulatory and market structures are developed sufficiently rapidly to support a three year transition period, then according to the larger scale AGL/ARENA trial, a minimum of 1,000 households in a given NEM region is required to provide the equivalent of 5 MW power plant. At face value the target replacement task of 600 plus MW exiting peaking generators may be achievable, and in a timeframe not inconsistent with the AEMC's proposed three year

[24] AGL Presentation, Institute of Energy, Melbourne, 19 June 2017

transition. The 2016 National Electricity Forecasting Report, for example, projected 613 MW installed integrated solar PV and storage systems across the NEM by 2020/21, with strong representation in South Australia and Queensland, but, reflecting the lower penetration of solar PV, relatively little penetration in Tasmania.[25]

What we don't know about the composition and behaviour of these systems as peaker replacements is more critical. What we do know or can reasonably assume suggests that more than the minimum number of systems will be required to deliver equivalent capacity to the market, but we don't know how what the larger number may be.

- We don't know how many of the systems installed will be export capable, that is, capable of providing any peaker replacement services. Battery uptake in some areas is being driven by DNSPs' limits on solar PV installations. In the absence of a battery further solar PV installations are prohibited. Even when a battery is installed, the connection is often export limited to zero.
- We don't know how much *incremental* capacity these systems are capable of providing to the market, but it's reasonable to assume that it's systematically less than the full potential contribution. These systems may also suffer from seasonal swings in the resources they are capable (or their owners willing) to supply to the grid.
  - Exports to the grid by residential and small commercial premises' connections are limited to a maximum of 5 kW. At 2pm on a sunny summer's afternoon, the incremental contribution of an integrated solar and battery system may be as little as zero, where exports are already at 5 kW, or as much as 5 kW assuming that the battery switches from full charge to full discharge *and* that the battery was previously taking the full capacity of the solar PV.[26]
  - On an overcast winter's morning, the system may not be constrained, but exporting to the grid may conflict with the owner's prioritisation.
  - In periods of high demand, system stress or where centrally coordinated load shedding has already commenced, as a result of distribution network performance or AEMO's actions these resources may not be available outside the local area, or at all. AEMO's current line of sight to performance of the distribution network is limited and, as a result, its capacity to rely on the contribution of these resources will require the development of communications and monitoring protocols and, potentially, some retrofitting of existing installations to participate in the wholesale market.
- We do know the energy contribution of these systems is limited. From full charge, the AGL systems will individually be able to provide around 7 kWh incremental energy to the grid outside peak solar generation periods, that is, their run time is slightly under 90 minutes. These systems can't substitute for the *energy* contribution of peaking generators.

[25] http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEFR/2016/2016-National-Electricity-Forecasting-Report-NEFR.pdf, p. 29

[26] This assumes a battery of 5 kW capacity. We've recently seen installers' offers where the battery size is so small it's not given, but the battery was around 1.5 kWh. Lots of battery installations are not necessarily the same as lots of battery capacity or energy.

- Most importantly, we don't have any insight into customers' preferences for the operation of these systems, or the interaction of those preferences with the payments to customers.
  - We don't know whether householders are likely to prioritise servicing their own needs in island mode over system-wide contributions, or to what extent previous or future experience of blackouts will change customers' priorities, so we don't know whether these contributions are likely to be *persistent*.
  - Unless there's a significant change in the payment structure, outside peak solar generation periods, a household or small business is still likely to maximise its return on investment by maximising self-consumption, not reselling to the wholesale market.
  - We don't know what households regard as the acceptable minimum price for the sale of their capacity and energy to the grid. While we may be able to draw some inferences from previous trials of Critical Peak Pricing about customers' willingness to participate in limiting consumption and maximising exports on a small number of occasions in hot weather, we have no information on customers' willingness to be on standby 24/7 to defend sold caps.
  - Alternatively, we don't know how many systems you need to aggregate to guarantee performance of a sold cap, so we don't know the effective cost of the service provided.

Current ARENA and other trials may provide some insight into the potential for capacity and energy to be provided by aggregated behind the meter resources, although given that the AGL South Australian project is in the first year of a five year trial, we anticipate that robust results are three plus years from being available. Current projects could provide some insight into the issues of diversification, aggregation and performance that need to be addressed if behind the meter resources are to make a material contribution to capacity and energy under five minute settlement. The AEMC needs to address the issues of through-year availability, persistence, delivery certainty and price, the characteristics required for these resources to provide equivalent risk management services to the market to exiting peaking generation. The AEMC should consider what is required for it to become a party to these programs and/or their detailed results to better inform its estimates of the potential contribution of aggregated behind the meter resources in replacing exiting cap providers.

4.2. Summary

Among the AEMC's list of potential replacements to provide capacity and energy no longer provided by exiting peaking generators following the introduction of five minute settlement, more flexible gas-fired generators (aero derivative engines of the type to be installed in South Australia) are capable of providing replacement capacity over a three year transition period. On a one for one basis, replacement costs could be expected to be $600 million plus, although in our view it's unlikely there'll be a one-for-one replacement. We expect some replacement, but rather than net new capacity, some loss of capacity. Cap prices could be expected to increase for two reasons: the new peaking generation configuration will bear more risk in defending sold caps than under current 30 minute settlement; and, since on a MW for MW basis the new technologies are dearer, investors will want to recover their additional capital.

Some combination of rapidly cycling and larger storage batteries could, in theory, replace exiting peaking generation capacity and some energy over a three year transition period. In practice, however, the economics of batteries require a range of income streams, most of which are absent, and, even if the income streams were present, it’s unclear that batteries would be installed without significant subsidies.

Depending on the project, PHES is capable of providing a larger volume of storage and supplying energy over a longer period than Peaker Replacement batteries.

More automated demand response and behind the meter aggregation are, at best, immature technologies. In both cases the ability of the technology to provide a material share of the services currently provided by cap providers, considering either capacity or capacity and energy, is currently unknown, and unlikely to be known with any degree of certainty within a three year transition period. There are measures the AEMC could take to better inform itself about the critical features of these technologies and the likely near to medium term contribution they may make to the NEM.

4.2.1. Capacity replacement

None of the candidates presents as a clear candidate for a near-term replacement under the proposed five minute settlement arrangements for exiting cap providers under the current 30 minute settlement arrangements.

Pumped hydro energy storage is the most prospective, but although construction estimates are as short as three years, that timeline’s calculated from the date permits have been granted. As a result, in a three year transition period, PHES isn’t a working candidate.

Some of the candidates – more automated demand response and behind the meter aggregation – are, at best, immature technologies. In both cases the ability of the technology to provide a material share of the services currently provided by cap providers, considering either capacity or capacity and energy, is currently unknown, and unlikely to be known with any degree of certainty within a three year transition period.

The ability of utility-scale batteries to provide replacement services is also questionable. The technology exists, but it’s doubtful that the economic model for unsubsidised entry at the scale required exists. Based on public domain information the conditions for unsubsidised entry continue to be absent.

4.2.2. Energy replacement

All of the AEMC’s nominated candidates for near term replacements to exiting OCGT and other generation fall short of replacing the energy supplied by existing peaking generators.

Pumped hydro energy storage is capable of replicating the performance of OCGT generators, depending on water storage and operating regime, and is the closest substitute, but it was omitted from the AEMC’s list of potential candidates presumably because of a view that the construction period was inconsistent with a three year transition period. PHES is a known quantity, participating in the NEM and with a known set of obligations. Utility-scale batteries are materially less so, as the presentation and discussion at AEMO’s recent Battery Forum indicated.

Figure 4.1 Daily half hou rs dispatched, selected generators by daily half hours dispatched, truncated at 15 half hours, FY 2016, number of days

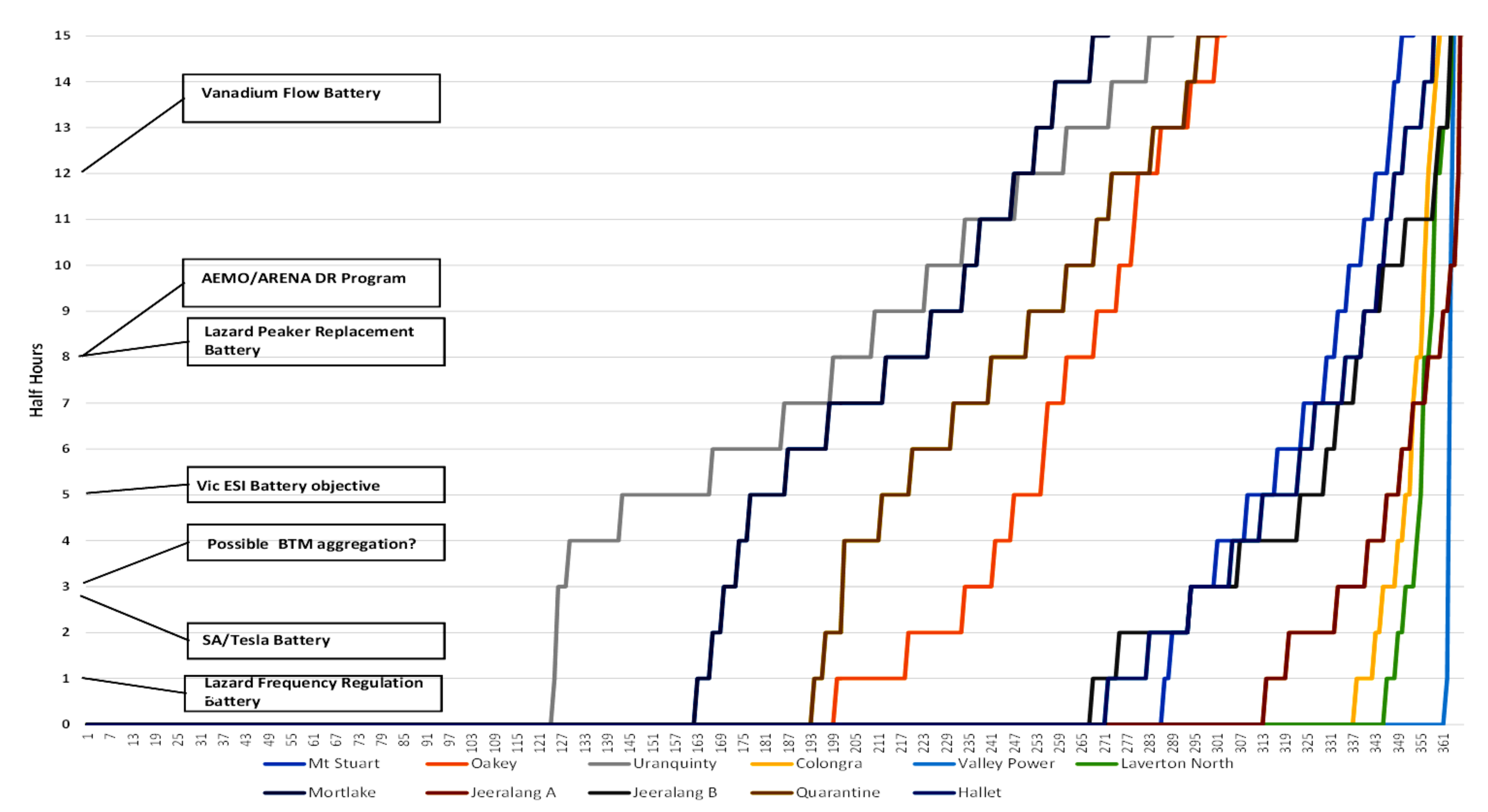


Figure 4.1 maps the energy potentially provided by the AEMC's candidates for near term replacements to exiting OCGT and other generation on a truncated version of Figure B. 6 and shows the maximum expected performance of the nominated candidates. Pumped hydro energy storage has not been included on the chart although it is capable of replicating the performance of OCGT generators, while aggregated behind the meter resources, if shown, would be clustered at the bottom of the chart, consistent with our view that these resources are more likely to provide services over "seconds to minutes" than material capacity or energy to the wholesale market.

4.3. Second round effects

In thinking about the potential candidates to provide peaker replacement services, we've devoted very little time to the discussion of second round effects. The subject is complex. Desirably, you'd want a NEM wide model capable of assimilating both different technologies and different drivers for generation commitment, representing households' choices in operating behind the meter generation, and businesses' maximising functions in providing demand response.

We don't have a model, but we have some observations that we think could be important.

- The AEMC's context for the proposed move to five minute settlement is the need to adapt the NEM to a technology neutral environment where emerging technologies are able to participate. However, in adopting a three year transition period where aero derivative engines and their equivalent are the most viable mature technology available, the AEMC both ignores the extent to which emerging technologies are already entering the market and risks shutting down the requirement for new flexible, but immature generation technologies until:
  - further growth increases market requirements
  - the technologies provide a demonstrably cheaper alternative, *or*
  - newly installed plant reaches the end of its economic life, 10 or more years into the future.
- Without having assessed IES's solution, observations by IES about the potential instability of dispatch where five minute settlement is combined with batteries and portfolios operating to hedge load concern us.[27] We think questions of this type and some of the unknowns in the operation of automated demand response and aggregated behind the meter resources could be considered as part of the AEMC's response to the Finkel Report's recommendations that the regulatory framework should be updated to facilitate proof-of-concept testing of innovative approaches and technologies.[28]
- Similarly, we think the AEMC's thinking on the market requirements for the entry of new technologies, and the timeline for these developments to occur would benefit

[27] http://aemc.gov.au/getattachment/e66cb21f-af35-447b-a3b4-3ddfab0f17d5/CS-Energy-consultant-report.aspx. We also understand that a similar form of instability is already displayed in the SA market, albeit at a smaller scale as a result of the automated dispatch of diesel generation in response to high dispatch interval prices. (Private communication, Seed and AEMO).

[28] The *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future,* June 2017, Recommendations 2.8 and 2.9.

from better, more granular insight into the results of trials funded by ARENA and other organisations into areas regarded by the AEMC as highly prospective. As Appendix C illustrates, there’s no current shortage of trials that could inform the AEMC about the characteristics, costs and issues of technologies it sees as highly prospective.

A. Five Minute Settlement Threshold Conditions Evaluation

Background

The Australian Energy Council is the industry body representing 21 electricity and downstream natural gas businesses operating in the competitive wholesale and retail energy markets. These businesses collectively generate the overwhelming majority of electricity in Australia and sell gas and electricity to over 10 million homes and businesses.

Project aims

To determine the threshold conditions which need to be satisfied for the proposed Five Minute Settlement rule change to be introduced.

Project Specification

Under the change to the National Electricity Rules proposed by Sun Metals, the National Electricity Market settlement interval will be reduced from 30 minutes to 5 minutes. The details of the AEMC's consideration of the rule change proposal are here: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement#.

The Energy Council has suggested that the rule change should only proceed if certain conditions are met, such as:

- sufficient fast-start scheduled supply (or equivalently firm and flexible demand response) existing to mitigate the risks of OCGT withdrawal;
- sufficient contract market liquidity in place to act as a buffer against the risk of a contraction in liquidity as market participants adjust to the new rules;
- signs that metering competition is delivering greater numbers of Type 5 meters; and
- adequate IT system readiness and budget for implementing the necessary changes.

There may be other indicators that the market is ready for the rule change, or can embrace the rule change with minimal disruption to normal operational and commercial arrangements. The tenderer will be expected to identify such indicators in its report.

The project requires the tenderer to:

(1) Identify the downside risks of premature implementation of Five Minute Settlement;

(2) Identify the market conditions which will affect the successful introduction of Five Minute Settlement; including:

  a. the natural sellers of new caps to replace the expected reduction in supply, and the timing of this supply;
  b. timelines around the expected market entry of new rapid response generation, including their costs and potential uptake;
  c. the potential for new hedging products to alleviate the shortfall in caps; and
  d. the potential implications for retail competition and the impact on energy consumers due to the disruption in the contract market (noting that the level of contract cover required under 5 minute settlement may not be the same as under 30 minute settlement);

(3) Discuss the relevance of the market conditions as they relate to Five Minute Settlement;

(4) Provide the current status of indicators of such conditions, showing historical values for the past ten years and projected values (and the level of confidence of such projections) for the next ten years;

(5) Identify any assumptions and sensitivities in the assessment of the market conditions and the projections;
(6) Identify any dependencies or relationships between the conditions;
(7) Report each condition's threshold beyond which Five Minute Settlement can be implemented, with minimal operational and commercial disruption; and
(8) Indicate the margin of error in such thresholds.

Outputs

A written report, including a short executive summary accessible to non-energy market experts, e.g. journalists, politicians.

Project timelines

19th July 2017:	Submission of tenders
24th July 2017:	Awarding of contract
18th August 2017:	Draft report provided to the Energy Council for review
25th August 2017:	Feedback provided by the Energy Council
1st September 2017:	Completion of project

Publication and confidentiality

As a member-based organisation, much of the Energy Council's strength is based on input from staff at its member businesses. For peer review, it will be important that we can circulate the draft report to a select group of member staff. We also prefer to refer to publicly available analysis in our advocacy so it's also important that we have the right to publish the final report.

B. Energy Edge's estimate of cap sale reductions: Underlying caps and cap market liquidity

Energy Edge's key finding that "across the market approximately 625MW of flat cap equivalent (23% of underlying cap volume) is likely to be withdrawn from the market, impacting retailers' ability to manage their financial market price and volume risk" relates only to *underlying cap sales*. The effects on *total traded cap market liquidity* can be calculated by extending their methodology and estimating the impact on traded caps, so as to estimate the effect on total traded caps.

Energy Edge recognise, but make no allowance for, caps provided within vertically integrated portfolios; the reliance on traded cap data, while understandable could potentially materially understate the effects on retail competition of a reduction in available caps.

The implications for generator capacity servicing the cap market can be estimated by considering the capacity typically required to support sold caps.

Finally, the implications for energy served by the affected generators can also be calculated by considering typical dispatch.

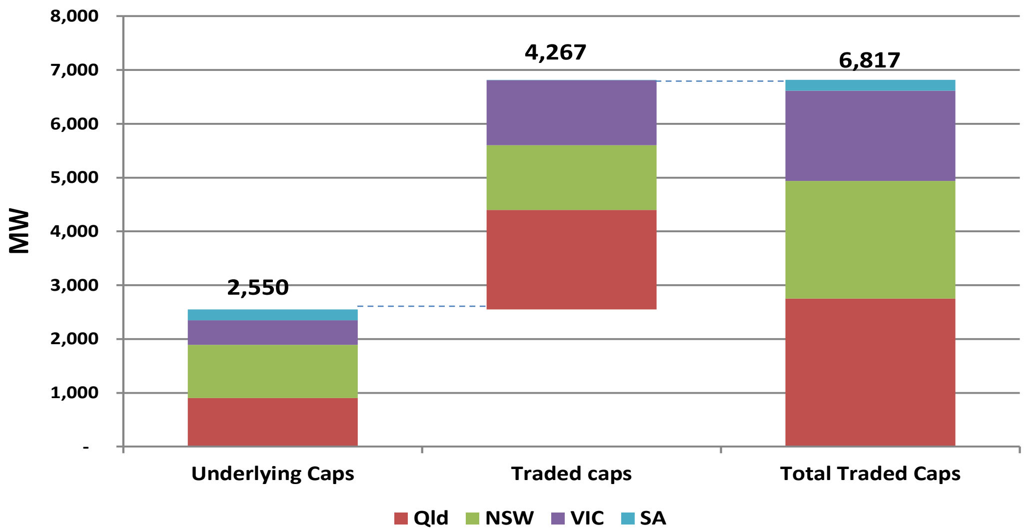
B.1 Underlying caps, traded caps and total traded caps: estimating the reduction

At a high level, Energy Edge takes the following approach to calculating the potential reduction in *underlying cap sales*:

- To calculate the effect of moving from 30 to five minute settlement, Energy Edge recalculates for the five minute case the analyses shown for the 30 minute case in Figures 17 to 20 and summarised in Table 3 of their paper. That analysis calculates the proportion of the time in FY 2015 and 2016 when a given generation technology was dispatched when the price for the relevant interval (settlement period or dispatch interval) is greater than $300 MWh.
  - The regional results from the analysis for the five minute case aren't shown; the results of their analysis by generating technology are summarised in Table 6 for all mainland NEM regions. Table 3, which shows the results for the 30 minute case, shows the results by generating technology and region.
- The average difference between the two sets of results for the natural gas (CCGT, OCGT and steam), hydro (conventional and pumped storage) and liquid fuel generation classes, shown in Table 6, is assumed to be representative for the technology class and is used as the basis for estimating the likely reduction in traded caps for mainland NEM regions.
- The reductions in cap effectiveness are applied to the mainland NEM regions in different proportions reflecting Energy Edge's judgement of what technologies are providing caps in the individual regions to get the different regional outcomes, shown in Table 7.
  - Total traded cap volumes from Table 1 are converted from GWh to flat (through-year) MW equivalents by region.

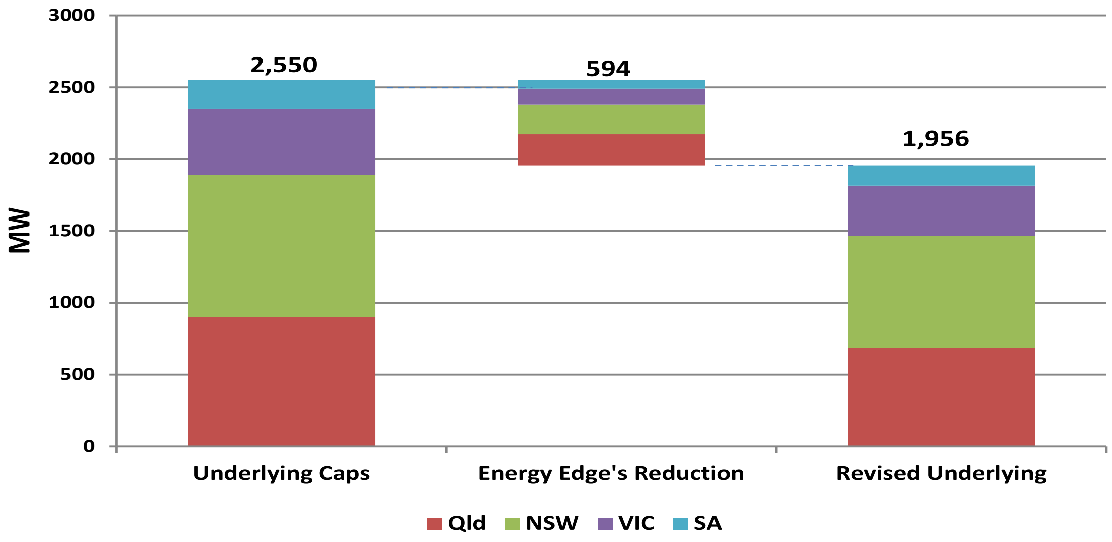
  - Total traded cap volumes, now expressed in MW, are in turn expressed either as "underlying caps", that is, *caps taken to maturity,* which are Energy Edge's focus or *caps traded but not taken to maturity* (referred to in this report as *traded caps)*. Energy Edge obtains underlying caps by using the Liquidity Ratio from Table 1; the volume of total traded caps is divided by the regional market-wide liquidity ratio to calculate caps taken to maturity for the regions considered (Figure B. 1).
- Energy Edge estimates that, based on the average difference between the 30 and five minute results at a regional level, there is a 23 percent reduction in *underlying caps* sold (Figure B. 2).
  - Energy Edge's focus on *underlying caps* highlights the implications of declining cap market liquidity for retailers' ability to manage their load and price swings: fewer traded caps results in lower total market liquidity and a reduction in the ability of retailers to hedge their underlying load. [29]

Figure B. 1 Total Traded Caps, by category and region, FY 2016, MW



[29] Our calculations, based on Energy Edge's data in Table 1 of their paper, slightly differ from theirs. Some of the difference is the result of rounding. In the case of OTC caps, the use of the liquidity ratio results in a perverse outcome in SA, because the liquidity ratio is less than 1, which results in underlying cap volumes exceeding total caps and a slightly larger reduction in underlying caps than would be expected from the application of the methodology. We have treated all caps in SA as underlying caps, which results in a slightly lower estimate than Energy Edge's for the reduction in underlying caps. We also have some concerns about a potential error originating in the AFMA 2015 Survey data and reflected in the estimated value of Victorian OTC caps in FY 2016. Adjusting this value in line with the NSW data, for example, would result in an increase in our estimated reduction in caps, likely higher than Energy Edge's original calculation.

Figure B. 2 Reduction in Underlying Cap Volumes, by region, FY 2016, MW



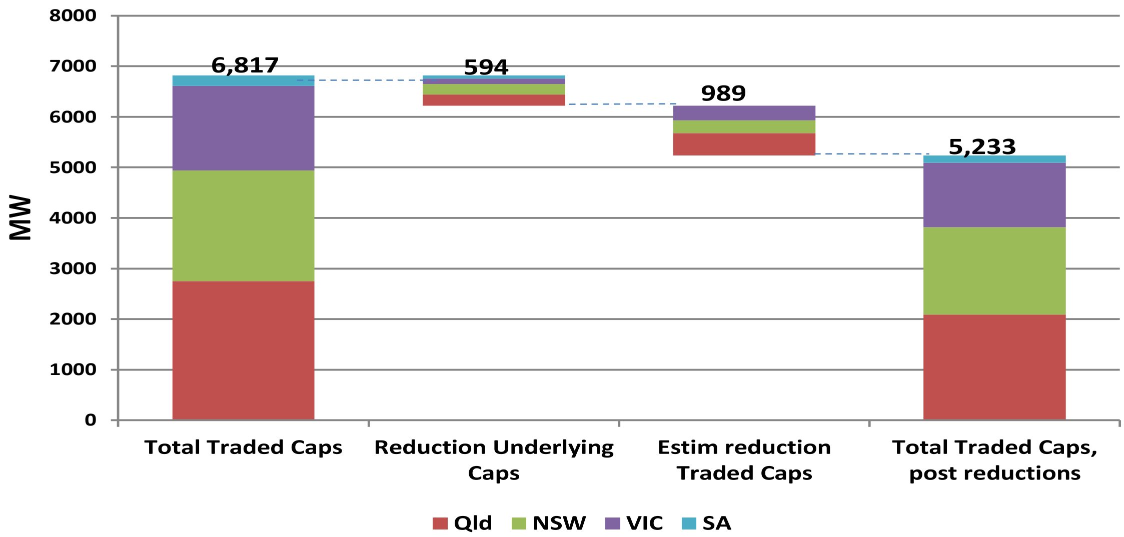
B.1.1 The reduction in total cap sales

The logic of Energy Edge's approach extends to total traded caps: any withdrawal of generator cap providers from the cap market as a result of a declining ability to hedge sold cap positions will reduce *both* underlying caps and *traded caps*.

- Energy Edge's classification is only notional.
  - The only difference between underlying caps (caps taken to maturity) and traded caps is that underlying caps are not (effectively) cancelled before the cap contract becomes operational.
- Underlying caps and traded caps are not different instruments, and are not sold by different generators.

Accepting this logic, then extending Energy Edge's approach to estimate the impact on all caps results in an estimated reduction of around 24 percent in total traded caps, made up of a reduction in underlying caps of 594 MW and in traded caps of 989 MW (Figure B. 3). A reduction of this size in cap sales represents a material reduction in cap market liquidity, affecting retailers without physical hedges in the regional markets in which they participate and/or without the financial backing to implement physical hedges.

Figure B. 3 Reduction in Total Traded Cap Volumes, by category and region, FY 2016, MW



B.2 Extending Energy Edge's analysis: contributions from other submissions to the AEMC

Submissions to the AEMC after the release of the Directions Paper commenting on Energy Edge's estimate can be divided into two broad categories: those focusing on the traded caps market data as a proxy for all caps provided in the market; and those focusing on the appropriate translation of the implications from the traded cap market to the physical provision of peak capacity at peak times.

B.2.1 Traded caps as a subset of all caps provided

The key extensions of Energy Edge's analysis of the effects of the proposed Rule Change on the caps market relating to the size of the total caps market are:

- the omission of some share of bilateral cap sales from the data
- the potentially significant share of caps that are effectively traded in internal trades by vertically integrated entities and not included in published data.

B.2.1.1 The omission of some share of bilateral cap sales from the data

Origin's submission raises the omission of some share of bilateral cap sales from the data.[30]

Energy Edge extrapolates from AFMA's 2015 Survey in estimating OTC derivative numbers for FY 2016 in the absence of AFMA data for that year. AFMA's view in its 2015 Survey was the omission of bilateral sales was unlikely to have been material. The AFMA Survey relied on members' trading data, adjusting recorded volumes for double counting where the same trade was reported by members on both sides of the same trade, and recognising trades where only one party to the trade was an AFMA member/surveyed by AFMA. However, bilateral trades between two parties neither of whom were AFMA

[30] http://aemc.gov.au/getattachment/b5bd508d-e7ba-4ee4-a683-83aa98169d5e/Origin-Energy-%E2%80%93-received-29-May-2017.aspx, p.2

members will not have been included. AFMA believes that, given the parties captured in its survey of electricity derivative trades, uncaptured trades are not a material omission from its data.

We have not estimated the impact of this omission.

B.2.1.2 The share of caps that are effectively traded in internal trades by vertically integrated entities and not included in published data.

The three major vertically integrated gentailers collectively serve the larger part of the residential and small commercial and industrial load in mainland NEM regions. The total hedging task is met by some combination of:

- traded hedges, which we can observe
- bilateral trades not captured in Energy Edge's data (see above)
- internal trades by vertically integrated entities (not directly observable, but likely significant given the vertically integrated gentailers' share of the residential and small commercial and industrial markets
- specialist products, including weather derivatives and demand response products (not documented in this report).

Including internal trades by vertically integrated entities in the estimate of caps sold is inappropriate in calculating *impacts on the traded cap market*: these trades do not participate in the market, even if the price at which these transactions occur may reflect market developments. However, the extent of internal hedges affected by the proposed Rule Change in vertically integrated portfolios should be included in any *estimate of the reduction of hedges available to retailers*, as well as *the replacement capacity required* and the costs of that replacement capacity, because of the role these hedges play in managing the risks of vertically integrated entities.

What addition to *caps taken to maturity* is required to reflect total NEM-wide cap requirements, including vertically integrated hedges?

- Energy Edge's stylized example of contractual cover in the NEM using a combination of swaps and caps suggests a NEM-wide (winter) requirement for caps taken to maturity – publicly traded *and* in vertically integrated entities – of around 2,500 MW with a similar corresponding summer requirement (Figure 34).
  - Typically, the corresponding summer NEM-wide Maximum Demand and the corresponding peak hedging task would be projected as higher than the winter peak requirement, likely between 2,750 and 3,000 MW based on AEMO's current projections of peak demand for summer and winter 2017.
  - These numbers seem too low to be used as an estimate of all caps – both traded and provided from within a portfolio – considering the share of residential and small commercial and industrial load served by the three major vertically integrated gentailers in mainland NEM regions.
  - Alternatively, if we were to accept a range of 2,500 to 3,000 MW for caps taken to maturity, then the liquidity ratio relied on in Energy Edge's calculation is *too low*: a higher liquidity ratio for caps would be consistent with a *lower* estimate for underlying caps in the traded markets, and allow for a more realistic proportion of caps taken to maturity to be provided within vertically integrated entities.

- Marsden Jacob Associates estimate the maximum required load flex (the difference between normal and maximum demand) in mainland NEM regions at just over 13,000 MW and the amount required in caps as 8,546 MW.[31] Marsden Jacob's estimate, which they acknowledge to be conservative, suggests that, once caps provided by the traded markets (Energy Edge's *underlying caps*) and hedges effectively provided by existing generation spare capacity are excluded from the estimate, then internal hedges amount to around 6,000 MW.[32, 33] At nearly 2.5 times Energy Edge's *underlying caps* and significantly higher than total traded caps, Marsden Jacob's estimate seems high.
  - Based on our own experience, Marsden Jacob's estimate appears to be too high. We *agree* that the upper end of their estimate could be seen as indicative of required capacity at peak demand. We *disagree* that retailers hedge to maximum demand: in our experience, retailers are more likely to hedge to the 50 percent POE summer maximum demand projection, not the 90 percent POE.
- We have arbitrarily decided on a range from zero to 2,500 MW to reflect vertically integrated entities' internal hedges. The extensions of and additions to Energy Edge's estimate are sufficiently large that, even if our estimate is conservative, in our view its conservatism does not materially affect our overall findings.
  - Consistent with Energy Edge's estimate of the effects of the introduction of five minute settlement on underlying caps, we assume that the effect on the internal hedges provided in vertically integrated entities is similar to that applied by Energy Edge to underlying caps. At the upper limit of our estimate this would imply a reduction of roughly 600 MW.
  - The underlying assumption – that the generation technologies vertically integrated portfolios use to hedge their risk are the same, and in the same proportions as Energy Edge uses in their calculations – may not be accurate. However, in the absence of a more detailed breakdown of Energy Edge's calculations by region, we are limited in our ability to replicate their work and have preferred to reflect our estimate on a NEM-wide basis, rather than allocate it to specific regions.

B.2.1.3 *Impacts on all caps, traded and vertically integrated: summary*

Figure B. 4 summarises the effect of our extensions of and additions to Energy Edge's analysis to take account of:

- The impact on traded caps not taken to maturity of the proposed Rule Change (-989 MW)
- Unobserved bilateral trades (0 MW)

[31] The balance is supplied by spare capacity from generators already dispatched. Marsden Jacob Associates, *Impact of 5-Minute Energy Settlement: Report prepared for Snowy Hydro,* 25 May 2017, pps.36-37

[32] Calculated by assuming existing plant spare capacity of 4,472 MW, underlying caps of 2,500 MW and using Marsden Jacob's estimate of plant required to start, 8,546 MW, from Tables 3 and 4, pps 36 and 37 in their report.

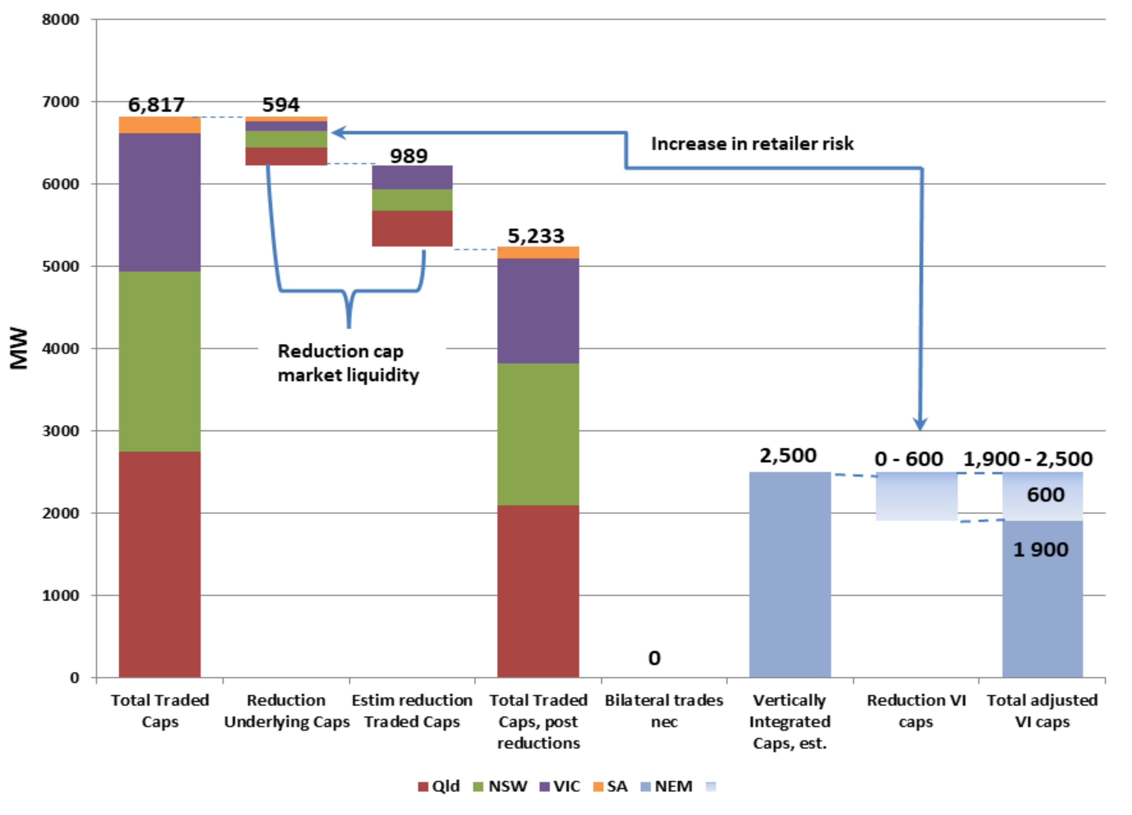
[33] In this context, ERM's argument that the closure of conventional generation, including the scheduled 2022 closure of Liddell Power Station, reduces retailers' ability to hedge is relevant. Liddell Power Station may not provide peak cover or caps, but its contribution to swaps sold, and to generation on peak days, is a source of both risk mitigation and load flexibility. http://aemc.gov.au/getattachment/bbc2f4b2-9abb-4afd-b95c-025a6a9df27f/ERM-Power.aspx, p.7

- Our estimate of hedges provided within vertically integrated entities, and the impact on hedges provided within those entities of the proposed settlement change (between zero and -600 MW).

These extensions and additions have two principal effects.

- The absolute reduction in total cap market liquidity is larger than Energy Edge's estimate: the total impact on cap market liquidity is 1,580 MW, a reduction of 23 percent in total traded caps.
- At its maximum, retailers' ability to hedge customer load flexibility is estimated to fall by around 1,190 MW, a combination of the reduction in underlying hedges and hedges provided within vertically integrated portfolios.
  - At its minimum, the reduction in retailers' ability to hedge customer load flexibility is 594 MW, although we regard this estimate as implausibly low, given the absence of any allowance for internal hedges written by vertically integrated entities.

Figure B. 4 Impact on all cap availability, by category and region, estimated MW



B.2.2 Translating caps written to physical capacity: adjustments

The key extensions of Energy Edge's analysis of the effects of the proposed Rule Change on the caps market to translate caps sold to the physical capacity required to back sold caps are: the adjustment required to reflect an "N-1" risk management approach to the generation capacity in backing sold caps; and, whether in using the relative reduction in a generator class's historic performance in capturing the benefits of price spikes in 30 and five minute settlements, Energy Edge has materially underestimated the reduction in generation capacity following the introduction of the Rule Change.

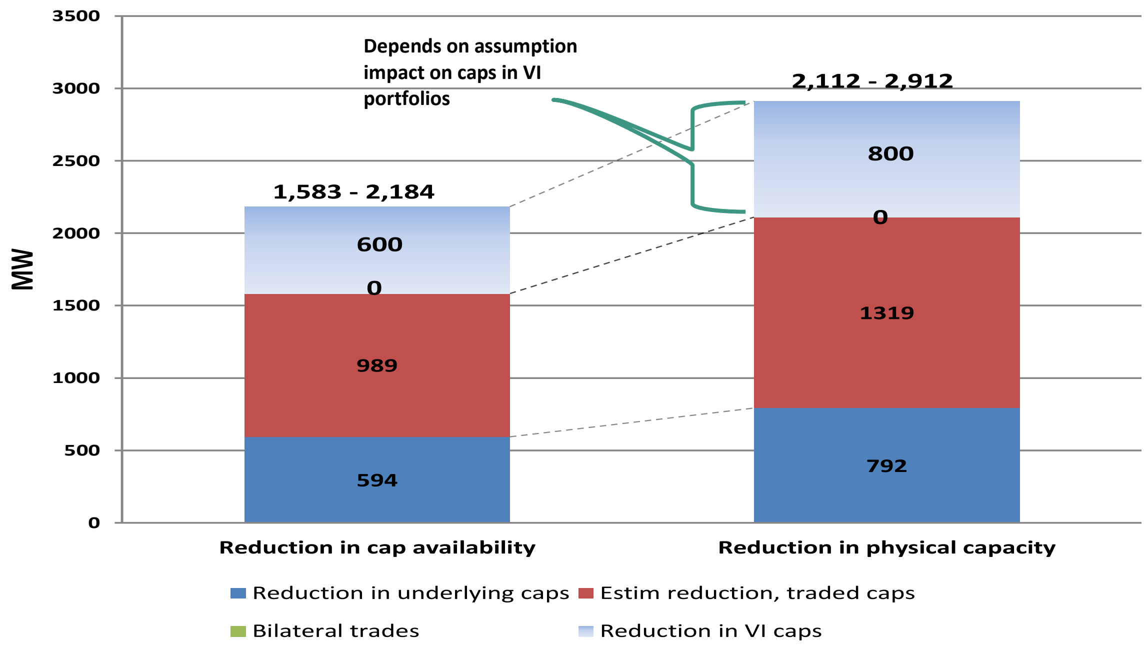
B.2.2.1 *Adjusting for "N-1" Rule*

Energy Edge effectively treats the reduction in caps sold as identical to the potential reduction in generation capacity in the event that existing cap sellers withdraw from the market. However, as Engie's submission argues, typically cap providers restrict cap sales to some proportion of their theoretical capacity to mitigate the risk of unexpected unit failure and to allow better coverage of the sold caps portfolio in the spot market through leverage.[34]

Engie suggests a ratio of sold caps to total capacity of 0.75:1. Applying this ratio to Energy Edge's calculations, and assuming that a withdrawal from the caps market results in an unacceptable reduction in generator income, then this would imply a withdrawal of between 2,110 and 2,900 MW generation capacity from the physical market following the withdrawal from the caps market (Figure B. 5).

Other submissions argue that an N-1 ratio may be too low given the higher risks of dispatch (equivalent to the lower effectiveness identified by Energy Edge) under five minute settlement: generators remaining in the caps market would need to apply a higher ratio of physical capacity to financial commitments to manage their risks.[35] We have made no adjustments to reflect this argument, although it's consistent with Energy Edge's findings of a reduction in hedge effectiveness across all current generation technologies in the NEM.

Figure B. 5 Reductions in cap availability and corresponding capacity impacts, NEM mainland regions, estim MW



[34] http://aemc.gov.au/getattachment/d58c7315-9fca-40d6-9989-ca943ff0f0f8/ENGIE.aspx p.5

[35] For example, http://aemc.gov.au/getattachment/bbc2f4b2-9abb-4afd-b95c-025a6a9df27f/ERM-Power.aspx, pps 9-10

B.2.2.2 *Other proposed adjustments*

Snowy Hydro's initial submission on the Rule Change argues that correctly calculated the impact on its willingness and ability to sell caps would be more than Energy Edge's calculation for the entire NEM mainland region.[36]

The two calculations take different approaches to calculating the potential loss. Energy Edge works from a combination of the published data for traded caps and the difference in the average ability of a given class of generators to defend 30 and five minute settlement, based on 2015 and 2016 data, and estimates that NSW hydro generators – to all intents and purposes, Snowy Hydro – have a 95 percent effectiveness under 30 minute settlement, while all hydro generators' effectiveness would fall to just under 78 percent with five minute settlement. Snowy Hydro's calculation looks at the theoretical maximum assuming 100 percent effectiveness under 30 minute settlement and 40 percent under five minute settlement, and no adjustment for an N-1 rule or its equivalent. However, Snowy Hydro's total theoretical cap production exceeds NSW cap sales in FY 2016, which amount to 2,190 MW compared to Snowy Hydro's theoretical maximum production of 3,000 MW.

If we applied Energy Edge's estimate of the reduction in effectiveness of hydro generators to Snowy Hydro's theoretical maximum load, then the reduction in underlying caps provided by Snowy Hydro would be 537 MW, or around 85 percent of the total estimated NEM-wide reduction in underlying caps calculated by Energy Edge. This suggests that, among other questions raised by Snowy in its submission, there may be issues in relying on *traded market data* as a basis for estimating the impacts of the proposed rule change. Latent capacity not included in the traded market data could also be affected by the proposed Rule Change.

We have made no adjustment to take account of Snowy Hydro's calculation; accepting Snowy Hydro's calculations would have a material effect on our extensions and additions to Energy Edge's calculations.

B.3 Summarising our extensions and additions to Energy Edge's analysis

Figure B. 4 and Figure B. 5 bring together the extensions and additions to Energy Edge's analysis that our review and our analysis of submissions to the AEMC on the Rule Change suggest should be included in any estimate of the impact on the caps market – traded and internal to the vertically integrated market participants – and the related impact on the physical capacity deployed in the physical market corollary of the caps market. Section B.4 discusses the related issues of the impact on *energy* given the dispatch histories of peaking generators.

Our extensions and additions to Energy Edge's analysis suggest:

- Total cap market liquidity falls by more than Energy Edge's estimate: the impact on total cap market liquidity is a reduction of 1,580 MW, or 23 percent.

[36] http://aemc.gov.au/getattachment/0f490c41-071d-4044-8f14-0b5355e64626/Snowy-Hydro-Limited.aspx, part 2.0

- Retailers' ability to hedge customer load flexibility is estimated to fall by between 594 and 1,190 MW, a combination of the reduction in underlying hedges and hedges provided within vertically integrated portfolios.
- A reduction in cap sales of between 1,580 and 2,190 MW would affect between 2,100 and 2,900 MW generation capacity.
  - This calculation is based on the "N – 1" ratio historically applied by generators to mitigate the risks of physical failure affecting the ability to meet hedge commitments.
  - An increase in the riskiness of providing caps could increase the ratio of physical capacity required to hedges sold, further affecting cap availability.

B.4 Implications for energy

On the basis of the AEMC's materials to date, we can draw very few conclusions about the implications for energy required in the event of the introduction of five minute settlement and the withdrawal of affected generation capacity currently supplying the cap market.

- The AEMC's Direction Paper and the prior Working Paper are not illuminating about the duration of the underlying cause, where one can be identified, of transitory price spikes. Are price spikes evidence of a trend, likely increasing, of greater transitory influences on demand or, alternatively, supply? Or are price spikes the result of participant incentives arising from interactions of the current settlement period, portfolio structures and generator physical characteristics resulting in short duration because the potential exposure of market participants to higher prices results in an increase in generation committed?[37]
- Because of this lack of clarity, the discussion to date has tended not to consider in any great detail impacts on the supply of energy of changes to the settlement period.
  - If price spikes are the result of transitory demand (supply) spikes, the effect on energy is likely to be very low, and the absence of any material discussion is appropriate.
  - If, on the other hand, generators are dispatched for longer than a single or small number of clustered dispatch intervals in response to an initial price spike, then observations that price spikes tend not to be clustered in settlement periods, or even on particular days, are not equivalent to demonstrating the proposition that the underlying cause of the spikes is transitory, and the energy implications are negligible.
  - Further, if there are material energy implications, then we also need to consider at what time of year these effects are most likely to occur and whether, because of the time of year, a small reduction in energy supplied may have implications for system security.

[37] The absence of any analysis looking at the duration of the underlying causes is particularly concerning when IES's argument about the potential for perverse incentives to give rise to an even larger number of destabilising price spikes as batteries are dispatched and then withdrawn on a five minute basis is considered. (IES, *reference required*) At a minimum, in making the Rule Change, we ought to be confident that the change will deliver fewer, not more price spikes.

- If the problem is one of transitory capacity ("seconds to minutes"[38]) or, alternatively, a combination of capacity and energy over a longer period ("hours to days"), then different types of new flexible generation and/or demand response entrant will be required.
- We can demonstrate that peaking generators are dispatched for longer than a single or small number of clustered dispatch intervals, particularly when the capacity dispatched is higher than average.

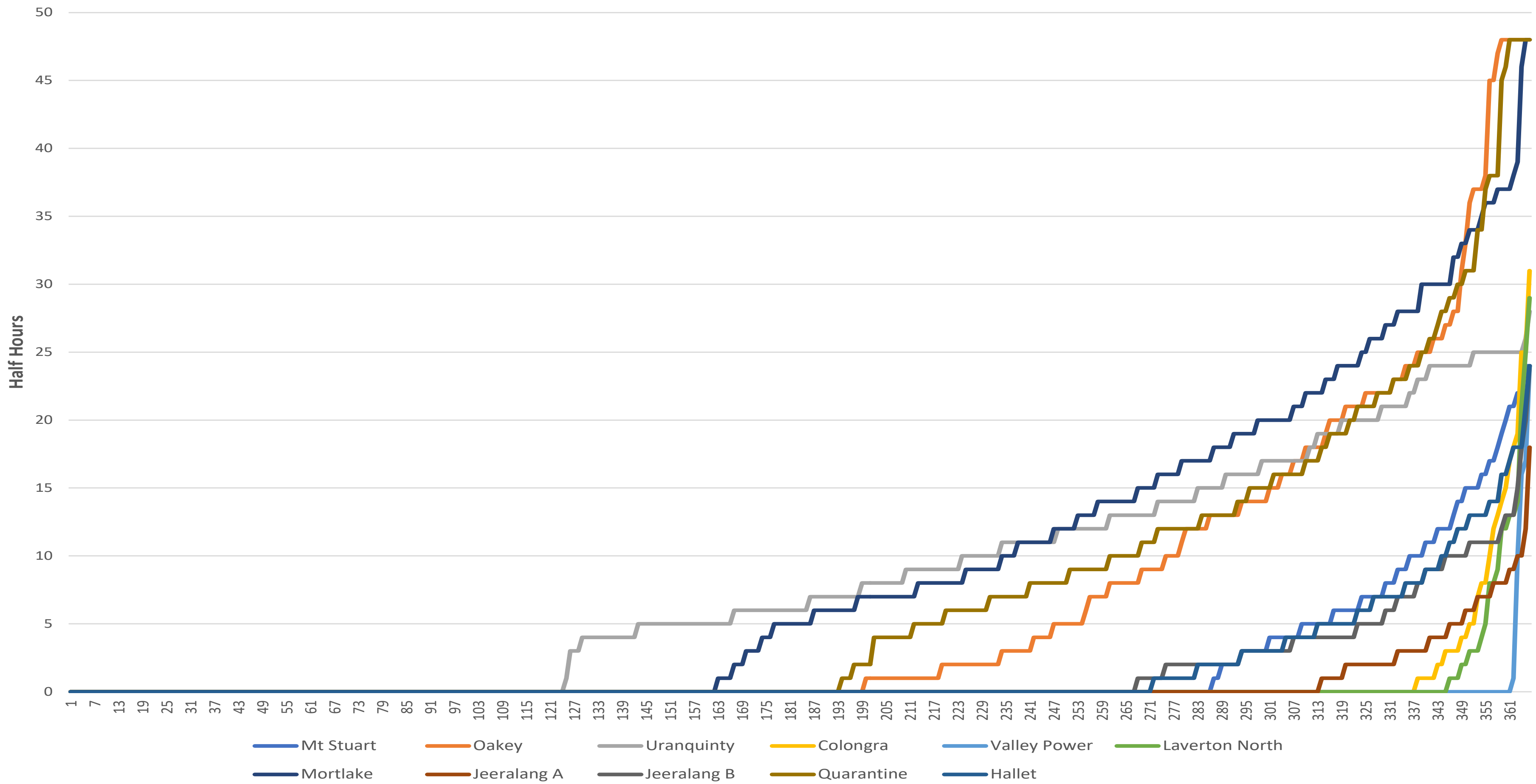
  Figure B.6 shows the proportion of half hours in a given day in FY 2016 that a higher than average commitment was required from selected OCGT generators over the period. For some of the selected generators, on more than a third of days in FY 2016, the generator was dispatched for 5 or more half hours on the day. For a smaller group of generators, dispatch of this duration occurred much less frequently. However, even for the group dispatched for a small number of days only, on a small number of days the generator was dispatched for more than 10 half hours on a given day.[39]

Rather than estimating the energy implications of the proposed Rule Change, in considering current proposals for new flexible generation technologies and demand response in Section 3 we have considered what the current target energy output from those proposals and initiatives is, and whether (and to what extent) current proposals are a substitute for current generation likely to be affected by the proposed Rule Change.

[38] https://rmi.org/news/grid-needs-symphony-not-shouting-match/, June 12, 2017.

[39] Seed calculations using published AEMO data. Dispatch shown includes all half hours on a given day where half hourly dispatch is higher than average dispatch for any half hour in FY 2016. The half hours may not be consecutive. Given the number of half hours in FY 2016 when generation was zero for the selected generators, average dispatch is typically a small proportion of total capacity.

Figure B. 6 Daily half hours dispatched, selected generators by daily half hours dispatched, FY 2016, number of days



C. Inventory of current trials:

Battery Storage

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
ARENA/Ergon Energy **(Battery/VPP)**	**Cannonvale Residential Solar PV and Battery. (QLD)** Ergon will undertake a 12-month pilot demonstration using 33 systems consisting of a 4.9kW SunPower PV array and a 12kWh/5kW Sunverge battery storage and control system. A particular innovation will be to demonstrate the ability of the systems to be centrally monitored and controlled as a virtual power plant.	August 2015	Late 2016; still current.	ARENA -$400,000 Ergon Energy –$2.22 Million (m) 165kW Battery capacity
ARENA/Carnegie Wave Energy **Battery**	**Garden Island Wave and Battery Storage Project (WA)** $7.5 million project will involve the construction and integration of 2 megawatts (MW) of photovoltaic solar capacity and a 2MW/0.5MWh battery storage system, coupled with Carnegie's CETO6 off-shore wave energy generation technology.	September 2016	Late 2017	ARENA -$2.5 m Carnegie Wave Energy – $5 m 2MW Battery capacity
ARENA/Lord Howe Island Board **Battery/Wind/Solar/Dem and Side Response**	**Lord Howe Island Renewable Energy System (NSW)** 1 MW of renewable energy generating capacity to the current diesel power generation system operating on Lord Howe Island. A combination of 450kW of solar PV, 550kW of wind and 400 kW of battery storage, along with stabilisation and demand response technology.	July 2014	Current	ARENA - $5.3m LHIB – $5.75 m 400kW Battery capacity
ARENA/Conergy **Battery/Solar**	**Lakeland solar and storage project (QLD)** Build and operate a 10.8 MW (AC) solar photovoltaic (PV) plant with 1.4 MW/5.3 MWh of lithium-ion battery storage near the town of Lakeland.	August 2016	Current	ARENA - $17.42m LHIB – $25.36 m 1.4 MW Battery capacity

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
ARENA/Windlab/Eurus Energy **Battery/Solar/Wind**	**Kennedy Energy Park (QLD)** Hybrid renewable energy facility situated in Hughenden in North Queensland developed in a partnership between Windlab and Eurus. This project will consist of 23.0MW DC/19.2MW AC solar photovoltaic (PV), 21.6MW wind and a 2MW/4MWh lithium ion battery storage facility.	March 2017	Current	ARENA - $18 m Windlab/ Eurus Energy – $102 m 2MW Battery capacity
Carnegie Wave Energy/CSIRO **Battery/Solar**	**Murchison Solar and Battery Facility (WA)** 1.6MW solar facility in combination with a 2.6 MWh battery energy storage system capable of diesel functionality to power the CSIRO's Square kilometer Array Pathfinder.	October 2015	Current	2.6 MWh Battery capacity
Powercor **Battery**	**Buninyong Battery Storage (Vic)** 2 megawatt battery will be housed in a standard 40 foot shipping container and is capable of providing 20% of the current powerline's capacity that services 6,400 customers. It will also deliver reliability of supply to people who live in Buninyong by reducing outages by 66 per cent.	December 2015	Commissioned early 2017	Powercor -$8m 2MW Battery capacity
SA Government/Tesla/ Neoen/Hornsdale Wind Farm **Battery Storage**	**Battery Storage large-scale grid stabilisation (SA)** 100 MW and the battery can store 129 MW hours. Provide enough power for more than 30,000 homes	July 2017	Late 2017	100 MW Battery capacity (potential)
ARENA/Reposit Energy **Battery/Smart Grid/VPP**	**Battery system trial (residential) (ACT)** The project involves piloting GridCredits, a battery storage control module that allows consumers to monitor electricity usage and access their solar power overnight and at peak times. Reposit will offer the 'GridCredits System' to volunteer households in	Dec 2014	Completed Oct 2016	ARENA - $446,000 Reposit – $932,000 No scale measure

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
	Canberra. The pilot will demonstrate the value of smart storage and also increase the understanding of how residential solar and energy storage systems can operate in Australia's electricity grid. The project has the potential to increase the uptake of rooftop solar and may allow more renewable energy to be connected to the grid.			
Transgrid/The University of NSW (UNSW)	**UNSW Battery Storage (NSW)** Tesla grid-scale Powerpack battery storage systems 250kW/500 kWh battery system. Combined with Transgrid's iDemand Automated Demand Response technology.	November 2016	Current	No financial details 250 kW Battery capacity
Transgrid/City of Sydney	**Alexandra Canal Works depot (NSW)** Grid-scale Powerpack battery storage systems (250 kilowatt, 500KW/h Powerpack), combined with Transgrid's iDemand Automated Demand Response technology.	June 2017	Current	No financial details 250 kW Battery capacity
Ausgrid	**Newington Grid Battery Trial (NSW)** 120kWh of Lithium Ion batteries and three 20kW inverters (one per phase) giving a total power output capacity of 60kW, contained within a standard 20 ft. shipping container.	Sept 2013	April 2016 Current	120 kW Battery capacity
Tas Networks/ANU/UNSW/UTAS/Reposit	CONSORT Bruny Island Battery Trial (Tas) 40 battery systems will be installed in homes on Bruny Island in Tasmania's south-east. Combined with rooftop solar generation, these batteries will be coordinated to alleviate congestion on Bruny's undersea power supply cable and to reduce the reliance on costly and polluting diesel generation during peak season, will help to stabilise network voltages within acceptable levels, while	March 2017	Current	ARENA - $2.9m Partners -$5.1 m 150 KW

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
	simultaneously enabling householders to make optimal use of their own solar power generation.			
SA Power Networks	**Salisbury Battery Storage Project (SA)** The trial by SAPN – the monopoly network provider in the state – will install around 100 Tesla Energy and Samsung batteries at deep discounts and install software from Canberra-based Reposit Power. It is being classed as an asset deferral project to avoid the need of building a new high transmission power line to Salisbury.	May 2016	Current	300 KW Battery capacity
Endeavour Energy	**Dapto Substation Battery Storage Project (NSW)** Endeavour Energy plans to trial the efficiency and reliability benefits of grid-connected battery storage systems. It will install a one megawatt hour battery storage system at the future site of its West Dapto Zone Substation in the Illawarra.	February 2017	Current	No financials 1 MW Battery capacity
ARENA/University of Wollongong	**Smart sodium storage system for renewable energy storage (NSW)** Development of a new sodium-ion battery architecture and a modular, expandable packaging system with integrated battery and thermal management systems will be developed, produced and validated through two applications: a 5 kWh battery at Illawarra Flame House, an award-winning net-zero energy home, and a 30 kWh integrated battery and energy management system at Sydney Water's Bondi Sewage Pumping Station.	April 2016	Current	ARENA - $2.7 m LHIB – $7.9 m 35KWh Battery capacity
Victorian Government	**Energy Storage Initiative** The Victorian Government is conducting a tender for up to two batteries providing a combination of 40 MW and 100 MWh to be installed in Western Victoria for summer 2018.	January 2017	January 2018	Victorian Government – up to $25 m ARENA – matching funding

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
				40 MW Battery capacity

Virtual Power Plants

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
ARENA/AGL Energy Ltd **(Battery/VPP)**	**AGL Household Virtual Power Plant (SA)** AGL to install 1,000 centrally controlled batteries in South Australian homes and businesses. The virtual power plant will be capable of storing 7 MWh of energy, with an output equivalent to a 5 MW solar peaking plant	February 2017	Current - 3 phases 1st phase -150 homes complete April 2017 2nd and 3rd phases current	ARENA -$5 m AGL – $15 m 300KW battery Capacity Installed When completed: 7MW Battery capacity 5MW Peaking capacity
ARENA/CSIRO **(Battery/VPP)**	**Virtual Power Station 2 (NSW)** This project builds on CSIRO's existing research, creating the next version of a virtual power station (VPS2) that can undertake pilot-scale testing of load, generation and energy storage coordination. A pilot-scale demonstration of the project will be integrated within a new residential development.	August 2014	Current	ARENA -$850,000 CSIRO – $1.54 m No scale measure

Demand side response

Proponent	Project\Description	Commencement	Anticipated Completion	Scale
ARENA/NSW Govt	**Pilot Demand Side Response (NSW)** This $15 million funding pool will be reserved for NSW projects, with the aim to generate 60-70 MW of demand response capacity to be available during extreme peak demand days and emergencies.	June 2017	Current	ARENA - $7.5m NSW Govt – $7.5 m 60-70 MW
Greensynch	**Software technology (Vic)** For VPP/Cloud Management of energy assets (Battery/Solar PV/Generation). Software aimed at Retailers, businesses, networks and operators.	Founded 2010		No financials No scale measure
ARENA/AEMO	**Demand response pilot program** ARENA and the Australian Energy Market Operator (AEMO) announced their intent to develop a demand response initiative to manage electricity supply during extreme peaks and grid emergencies.	May 2017	2020	ARENA - $22.5m 100 MW (projected)
Ausgrid	**Demand Management Hot water load control trials (NSW)** PROJECT 1: Control of small hot water systems: focused on investigating a demand management solution for electric hot water systems on continuous electric supply. There are around 300,000 customers with small hot water systems with storage of less than 100 litres. PROJECT 2: Subsidised controlled load connections targeted at the estimated 100,000 customers with eligible hot water systems but who are not connected to a load control tariff. PROJECT 3: Controlled Load 2 summer scheduling focused on optimising the summer load control schedule for our existing Controlled Load 2 customers with the aim of obtaining summer peak demand reduction benefits in the summer afternoon period. There are 153,000 customers	2013	Complete Aug 2016	Across the whole Ausgrid network the summer afternoon peak reduction achieved by changing the load control schedules is estimated to be 18 MW.

Proponent	Project\Description	Commencement	Anticipated Completion	Scale
	in Ausgrid's network area on the control load 2 tariff.			
Ausgrid/AER	**Demand Management Incentive Scheme and Innovation Allowance (DMIS/DMIA)** The AER has commenced developing a new demand management incentives scheme and innovation allowance mechanism. This scheme and allowance mechanism complements Ausgrid's ongoing reforms targeting consumer choice and more efficient network pricing outcomes. These include our work on tariff reform, metering contestability, ring-fencing and a rule change to strengthen the transparency and efficiency of replacement expenditure.	August 2016	Effective Start Date October 2017	No financials No scale measure
Ausgrid	**CoolSaver trial (NSW)** Ausgrid analysed the half hour meter data for 250,000 Ausgrid residential customers on key peak demand days. The results, described in Figure 1 below, show that on the historical peak day of 3 Feb 2011, electrical demand increased by an average of one and a half times (147%) in comparison with a moderate summer day a week later. This increase is equal to about 400 MW of electricity demand, or 1600 watts per household. It is estimated that in 2011, residential air conditioners comprised about 1300-1700 MW of the overall Ausgrid system peak of 6300 MW, or about 20-25% of total peak demand. 64% or about two thirds of households in NSW had an air conditioner. The trial engaged customers who installed specific air conditioners and gave them a discount to engage in a trial.	Summer 2012/13	Complete Summer 2016/2017	No financials No scale measure
United Energy/Greensync	**Demand Side Response Mornington Peninsula (Vic)** GreenSync has entered into a partnership with Victorian utility United Energy (UE) to deliver a landmark demand response and energy storage project on the Mornington Peninsula. This was an initiative done after	August 2016	2021	No financials No scale measure

Proponent	Project\Description	Commencement	Anticipated Completion	Scale
	the development of demand side software of 2 PHD candidates at Monash sponsored by United Energy. No details of size or number of households involved. It is claimed to be an "Asset Deferral Project"			
Ergon Energy	**Network Demand Management Mt Isa (Qld)** Reduce enough peak demand to defer the proposed Sunset Substation by 3 years. Required demand expected to be contracted and only on-going maintenance, measurement and verification will be required.	2014	2017	Deferral of asset renewal by stabilisation of existing power usage. No Net MW savings
Ergon Energy	**Barcaldine Network Support Agreement (Qld)** Contract to renew the network support agreement for the Gas turbine at Barcaldine. Due to the high cost of the Network Alternative, it has always been the preferred approach to use embedded generation to manage security to the Barcaldine and Central West areas. The period of the contract is five years, after which time the local security requirements will be reviewed again, in line with the potential renewal of this contract.	2014	2019	Deferral of asset renewal by stabilisation of existing power usage. No Net MW savings
Ausnet	**Mooroolbark mini grid (Vic)** 14 homes in a suburban street with a combination of solar panels, 10kWh storage batteries and the main power grid operating as a unified energy system, i.e. a mini grid. One of the most technically-advanced components of project is the stabiliser, which allows the mini grid to operate independently of the main grid. The stabiliser is a smart battery storage system that smooths out short term variations in energy supply and consumption across the mini grid by either delivering or absorbing power. The stabiliser operates using renewable and stored energy. The stabiliser is connected to the main power grid by a switching device. It uses this device to control the transitions of the mini grid to and from the main power grid. The entire mini grid is managed by a cloud-based	April 2016	Current	No financials 58.8KW

Proponent	Project\Description	Commencement	Anticipated Completion	Scale
	software platform called MicroEMTM , developed by GreenSync. This software is in constant communication with the power system at each home, as well as the stabiliser and switching cabinet. The software platform monitors and analyses data and sends alerts and notifications to the 24-hour operations team, ensuring safety and applying the mini grid operating parameters.			

Pumped Hydro Energy Storage

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
Genex	**Kidston Pumped Storage Hydro Project (QLD)** Pumped hydroelectric storage power project. 450MW of rapid response, flexible power for delivery into Australia's National Electricity Market (current materials suggest revised target of 250 MW). To complement the Kidston solar project phase 1 (50MW) and phase 2 (270MW).	2015	2015 -Feasibility Study (ARENA/Genex 10.2m) 2016 – $300 m of funding sought, 20 year Qld govt contract signed for power 2017 – Phase 2 feasibility study 2018 – Phase 1 solar complete	Pumped Hydro Feasibility study ARENA $4 m Genex $6.2 m Solar Farm Phase 1 – ARENA $8.9 m Genex $117.1 m Phase 2 450MW (Potential)
ARENA/Energy Australia	**EnergyAustralia South Australian Pumped Hydro Energy Storage**	April 2017	Current	ARENA - $453,000

Proponent	Project/Description	Commencement	Anticipated Completion	Scale
	(PHES) Feasibility Study Proposed 100MW of pumped hydro energy storage			EnergyAustralia – $549,000 100MW (potential)
Snowy Hydro Limited	**Snowy 2.0 PHES facility (NSW)** Snowy 2.0 will be able to provide an extra 2,000 MW of new renewable capacity and provide increased energy security and stability. The most prospective project could increase the capacity of the 4100 megawatt Snowy Scheme by 50 per cent and result in a power station at least as powerful as Snowy Hydro's 1800 megawatt Tumut 3 Power Station, which already includes pumped hydro capability. The Snowy 2.0 Feasibility Study will be completed by the end of this year.	March 2017	Feasibility Study Dec 2017 Current	2,000 MW (potential)
ARENA/Energy Australia/Mei/Arup Group	**Cultana seawater PHES facility (SA)** Located in the Spencer Gulf of South Australia, the proposed project would have the capacity to produce around 100 megawatts (MW) of electricity with six-to-eight hours of storage. To date, only a feasibility study.	February 2017	2020/21	100MW (potential)
ARENA/ANU/ElectraNet/Vtara Energy Group	**Atlas of Pumped Hydro Energy Storage** The Atlas will map potential short-term off-river pumped hydro energy storage sites. A blue print and cost model to integrate the technology into the electricity grid at national, state and regional levels will be developed.	November 2016	Current: initial sites for Queensland, NSW, SA and Tasmania have been published	ARENA - $449,000

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