Australian Energy Market Commission

REVIEW

FINAL REPORT

GAMING IN REBIDDING ASSESSMENT (GRATTAN RESPONSE)

28 SEPTEMBER 2018

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The wholesale cost of energy in the National Electricity Market (NEM) increased significantly between 2015 and 2017. This was driven by a number of factors including the retirement of generating plant and increases in the costs of fuel for thermal plant, particularly in relation to gas and black coal. Consumers felt the impact of wholesale cost changes through increases in the retail price of energy between 2017 and 2018.

2 Concerns around higher wholesale costs, industry structure, bidding behaviour and their effect on consumer bills have informed a number of key studies by government bodies in recent months.

3 The ACCC'S Retail Electricity Pricing Inquiry published in July 2018 found, amongst other things, that higher wholesale prices have been driven by high levels of concentration in the market, combined with fuel cost factors, rather than identifiable uses or abuses of market power by particular generators to "spike" the price. The report made a number of recommendations to address concerns about concentration and to promote new investment and greater competition in generation.

4 A report by the AER, in December 2017, examining the performance of wholesale markets in NSW examined the reasons for wholesale price increases in NSW in 2017. The report highlighted fuel supply issues in relation to gas and black coal and the retirement of Hazelwood in Victoria. It also identified other factors that the AER thought should be considered over a longer period including market structure and barriers to entry.

The Grattan report

5 In July 2018, the Grattan Institute published its report *Mostly working: Australia's wholesale electricity market*. The report examined the recent increases in wholesale electricity costs and provided an in depth analysis of the drivers. It noted that the value of electricity traded in the NEM increased from $8 billion to $18 billion from 2015 to 2017.

6 In breaking the causes of the increase down, the report attributed:

- almost 60 per cent or $6 billion of the increase to a tighter supply demand balance following the retirement of two large coal fired power stations, Northern in South Australia in 2016 and Hazelwood in Victora in 2017
- about 40 per cent of the increase or $4 billion was attributed to increases in the cost of key inputs, especially gas and black coal.

7 In both cases the report notes the resulting higher wholesale prices were a sign of the market operating effectively. These conclusions both support and add to other work completed in relation to wholesale cost changes.

8 The report went on to note a third driver of higher wholesale prices. The issue, the report maintained, is that generators have been "gaming" the system by using their power in concentrated markets to create artificial scarcity of supply and force up wholesale prices. It is estimated gaming contributed around $800 million to the wholesale cost of electricity in both 2016 and 2017, with Queensland making up two thirds of this cost. The report claims this

cost increased by $250 million between 2015 and 2017 as a result of increased gaming, accounting for some of the $10 billion increase in wholesale costs.

9 Three factors were seen to contribute to gaming in the wholesale market:

- a high concentration of generation ownership
- a heavy reliance on generation technology that cannot respond quickly to outages or demand spikes
- market rules which allow rebids at the last minute, when few, if any, generators can respond.

Request from the Minister

10 The Honourable Josh Frydenberg MP, the Commonwealth Minister for the Environment and Energy, requested the Australian Energy Market Commission (Commission), working with the Australian Energy Regulator (AER), investigate claims made by the Grattan Institute around the cost of gaming in 2017.

11 As well as verifying these findings, the Minister requested that the Commission make recommendations on appropriate solutions to address this issue, including whether rule changes are required. The Minister requested the Commission provide the report by 30 September 2019.

Assessing the $825 million costs

12 The Commission and the AER assessed Grattan's analysis of gaming and consider the definition of gaming that it uses is too broad. This definition inadvertently labels instances of price volatility and rebidding as gaming.

13 Replicating Grattan's analysis with the benefits of more granular data provided by the AER, instances of price spikes were assessed in greater detail using the AER's events register. This register records the primary causes for significant price spikes. Far from being the only cause of price spikes, generator rebidding is one of fourteen possible factors identified in the AER's events register.

14 Generator rebidding was found to be the primary cause for $243 million of price spikes in 2017, rather than $825 million. The cost of price spikes, for which rebidding is the primary cause, has fallen since 2015, not increased. Where volatility has increased between 2015 and 2017, this has been driven by other factors unrelated to rebidding, in this case a combination of instances where actual demand is different to forecast and issues with generator availability, often associated with a generator tripping.

15 Further, of the $243 million associated with rebidding, $214 million of this has occurred in Queensland, and virtually all in January and February 2017 before the Queensland government directed Stanwell to moderate its bidding behaviour. There have been minimal price spikes since then.

16 As a result, the cost of price spike events, in which rebidding was the cause, represents only one per cent of the wholesale cost of energy in the NEM in 2017. This cost, however small, is unlikely to have been passed through to consumers in 2017. Retailers typically enter into

hedge contracts that prevent volatility and short term changes in wholesale market prices being passed onto consumers. In addition, this measure of the cost of rebidding makes no allowance for the beneficial impact of rebidding in lowering wholesale prices.

17 The role of rebidding in facilitating efficient wholesale prices and investment outcomes should not be underestimated. The rebidding process allows market participants to respond to changing market conditions and is integral to the daily operation of the power system. It also, in the longer term, signals the market need for new generation including the type of generation needed (such as fast start technology) and where it is best located.

18 The rebidding process is likely to become more important in the future in reducing wholesale price volatility as more flexible and fast response generation and demand technologies enter the market. This is highlighted by the important role rebidding has played in the operation of the Hornsdale battery.

Gate closure recommendation

19 The Commission has considered bidding rules, bidding strategies and bidding behaviour in the NEM at great length, both in the *Bidding in good faith* rule completed in December 2015 and in the *Five minute settlement* rule made in November 2017.

20 While the Commission does not consider the case for changing the rebidding arrangements has been made in Grattan's report, we nevertheless have considered the proposal for gate closure put forward.

21 In Grattan's report the mismatch between the response time of generators in the market and the times within which rebids are allowed, provides generators with the opportunity to game the market by making late rebids so that other generators cannot respond. To address this, the report proposed a gate closure mechanism that would only allow rebids to lower wholesale prices within 30 minutes of dispatch. Rebids to raise wholesale prices could only occur for specific reasons (such as a generator outage) and would need to be approved by the market operator.

22 A gate closure mechanism would compromise efficiency if participants were hindered in their response to changing market circumstances, and has the following drawbacks:

- the selection of a 30 minute gate closure brings forward the period in which gaming may occur, rather than eliminating it
- it may distort the market in that different generators have different capabilities to turn on or off and ramp up or down (for example, coal generators may take many hours, while batteries can respond almost instantly)
- the proposed mechanism may give non-scheduled generators and most loads an unfair advantage given they can still change their intentions right up until dispatch
- the type of asymmetric gate closure mechanism proposed would provide generators with incentives to increase their bids in pre-dispatch to afford them greater flexibility beyond the gate closure cut off. As a result, pre-dispatch forecast prices would tend to be higher than the prices that eventuate at dispatch and market confidence in the signals provided by the pre-dispatch process would be undermined.

Market concentration

23 To the limited extent that bidding and rebidding behaviour in the market are seen to be a problem, the analysis shows that they are driven by high levels of market concentration. These issues related to industry structure should be addressed by policies that lower barriers to entry and promote efficient new investment.

24 This finding is consistent with the conclusions of the ACCC report, published in July 2018, "Restoring electricity affordability and Australia's competitive advantage". The ACCC made a number of recommendations targeting reductions in market concentration and barriers to entry, and the promotion of new investment. These recommendations are currently under consideration by governments.

25 Recent trends in generation investment, as well as the announcement by the Queensland government on 30 August 2018 in relation to the establishment of CleanCo, a third government owned generator that will focus on the development of renewable energy generation, may also help to alleviate the impacts of market concentration.

26 Changes to the rules concerning bidding in the NEM are unlikely to resolve issues in the wholesale market that are driven by industry structure. It is more effective to deal with these issues directly, thereby avoiding the drawbacks to efficiency of changing the market rules themselves.

CONTENTS

APPENDICES

TABLES

FIGURES

1 INTRODUCTION

In July 2018, the Grattan Institute published its report *Mostly working: Australia's wholesale electricity market*.[1] The report examined recent increases in wholesale electricity costs and the associated increase in consumer bills. One claim in the report is that generators have been gaming the system by using their power in concentrated markets to create artificial scarcity of supply and force up wholesale electricity prices resulting in costs of $825 million in 2017. It was this aspect of the report that the Honourable Josh Frydenberg MP, in his then capacity as Commonwealth Minister for the Environment and Energy, requested the Australian Energy Market Commission (Commission or AEMC) and the Australian Energy Regulator (AER) to investigate.

The Minister requested the Commission and the AER verify Grattan's findings and make recommendations on appropriate solutions to address this issue, including whether rule changes are required.

To verify Grattan's analysis and assess its proposed solutions, this report is structured as follows.

- Chapter 2 summarises Grattan's analysis of gaming, including:
  - how it identifies instances of gaming
  - what factors enable gaming
  - its estimate of the cost of gaming in the wholesale market.
- Chapter 3 provides the Commission's assessment of the Grattan analysis. This includes:
  - an analysis of Grattan's definition of gaming
  - the causes of the gaming instances identified by Grattan
- Chapter 4 describes the role of rebidding in the pre-dispatch process, and its value as a mechanism that facilitates efficient pricing outcomes in the short term and efficient investment outcomes in the longer term.
- Chapter 5, while noting that the Commission's analysis does not support the case for market design changes, examines Grattan's solutions to address gaming, including:
  - the proposed gate closure mechanism, and examination of Grattan's views on the shortcomings of the *Bidding in good faith* and *Five minute settlement* rule changes
  - considering introduction of a day ahead market, a pivotal supplier test and increased demand response
  - analysis of the gaming instances identified in Queensland and the importance of market power as a driver of volatility, rather than rebidding. Consideration of proposals to split the two Queensland government owned generators into at least three to reduce market power in the state.
- Chapter 6 summarises the Commission's conclusions.

1 Grattan Institute, *Mostly working - Australia's electricity market*, https://grattan.edu.au/report/mostly-working/, July 2018.

2 GRATTAN'S ANALYSIS OF GENERATOR GAMING

The Grattan report analysed the causes of recent increases in wholesale energy costs. It noted that the value of electricity traded in the NEM increased from $8 billion to $18 billion from 2015 to 2017. Grattan concluded that most of the $10 billion increase in costs could be explained by a tighter supply-demand balance and higher input costs, and that the resulting higher wholesale prices were "a sign of the market operating effectively"[2]. However it also estimated that generator gaming could contribute as much as $800 million to the wholesale cost of electricity in some years, with two thirds of this cost originating in the Queensland market between 2012 and 2017.[3]

This chapter summarises:

- how Grattan defines gaming and estimates its cost
- the factors Grattan identifies as contributing to gaming
- Grattan's proposed solutions to eliminate gaming.

2.1 Defintion of gaming

The Grattan report defines gaming as:[4]

> … behaviour that is within the prescribed rules but results in highly favourable outcomes for some of the players. Gaming is contrary to the intent of the system.

While Grattan note that gaming "is notoriously hard to identify",[5] it considers instances of gaming have the following characteristics:

- A generator rebids close to the dispatch interval, either reducing its available generation or moving output into higher wholesale price bands, creating an artificial scarcity of supply.
- The late rebid causes a spike in the dispatch price because other generators cannot respond quickly enough.
- Other generators quickly respond and drive the wholesale price back down.

Grattan considers that it is rare for genuine supply scarcity to occur for only five minutes in a half hour and this makes it likely the wholesale price spike has been caused by gaming.

In order to specifically identify and quantify instances of gaming, Grattan identified all trading intervals between 2011 and 2018 where:

- the difference between the highest and second highest five minute dispatch interval prices is more than the half-hour average
- the half-hour average is less than $5,000 per MWh.

2 ibid. p. 13.
3 ibid. p.24. Average cost in Queensland compared to NEM total, 2012-2017
4 ibid. p. 26.
5 ibid. p. 3.

Grattan excluded intervals with a half-hour average wholesale price greater than $5,000 per MWh as the AER is required to investiage these and "they are more likely to be associated with genuine scarcity."[6]

While Grattan assumes that all trading intervals that meet the above criteria are instances of gaming, it acknowledges "some genuine supply constraints may be captured" by the definition but "some gamed intervals are also likely to be excluded".[7] As such, it acknowledges some imprecision in its definition.

Grattan calculates the total cost of gaming by taking each of the trading intervals it has identified as an instance of gaming and multiplying the difference between the highest and second highest dispatch price by electricity consumption for the trading interval. Using this method, it calculates total gaming costs of around $600 million per annum between 2013 and 2015 and around $800 million per annum in 2016 and 2017. Two thirds of this cost has originated in Queensland in the past five years. The report notes that gaming has increased wholesale costs in South Australia and Queensland "by around 10 percent in recent years".[8]

2.2 The factors identified as contributing to gaming

Grattan suggests three factors contribute to gaming in the wholesale market:[9]

- a high concentration of generation ownership
- a generation mix that cannot respond rapidly to outages or spikes in demand
- market rules, which allow rebids at the last minute when few, if any, generators can respond.

Grattan noted that the concentrated generation ownership in Queensland and South Australia, and the limited interconnector capacity to each region, mean wholesale price spikes are more likely to occur, even when demand is not particularly high. Price spikes were "less frequent in NSW and Victoria, where there is more competitive pressure from multiple interconnectors and local generation".[10]

The Grattan report also contrasts current generation technology constraints with the market rules. In particular, it notes that few generators can respond to market changes in less than five minutes and that some require several hours. Against this, the market rules allow rebids in timeframes that are too short for generator responses. On this basis, Grattan consider the market rules are not well suited to the current generation mix and suggests that "(a)ligning bidding rules with the current mix of generation technologies will improve the efficiency of the NEM."[11]

6 ibid. p. 27.
7 ibid. p. 26.
8 ibid. p. 27.
9 ibid. p. 30-31.
10 ibid. p. 30.
11 ibid. p. 33.

2.3 Solutions to eliminate gaming

To address the problem, Grattan proposes the following:

- introducing a gate closure mechanism that only allows late rebids to lower the price unless specific circumstances exist (for example, a generator breakdown)
- to split the two Queensland owned generators into (at least) three. This finding preceded a similar recommendation from the ACCC in its report "Restoring electricity affordability and Australia's competitive advantage"[12]
- other market changes such as a pivotal supplier rule, a day ahead market and demand response mechanisms, "if smaller changes prove ineffective".[13]

In support of the gate closure mechanism, Grattan considers it would better align the market rebidding processes with the response capability of the current generation mix. This is proposed because in Grattan's view, previous rule changes have not solved the issue of gaming. In particular, Grattan refers to the *Bidding in good faith* rule and the *Five minute settlement* rule.

In relation to the *Bidding in good faith* rule, which prohibits false or misleading offers, Grattan states without further description that "(g)enerators adjusted their tactics and continued to game the system."[14]

In relation to the *Five minute settlement* rule, Grattan notes:

- the rule will stop generators benefitting from a high 30 minute wholesale price after a five minute price spike, and this will improve the efficiency of the wholesale market
- consumers that can adjust their demand in response to price signals will no longer "get caught out"[15] by having their consumption price spiked.

However, Grattan considers the *Five minute settlement* rule may also "make things worse"[16]. Its specific claims are that:

- a generator able to game the system may gain an increased reward under the new rule. Whereas the current 30 minute settlement process averages the prices from the component five minute dispatch intervals, Grattan state actual five minute wholesale prices may result in increased generator revenue. The worked example Grattan provided actually shows less revenue, but Grattan claim there will still be an incentive to "play the game."[17]
- if wholesale price spikes are caused by artificial supply shortages then the *Five minute settlement* rule will not encourage the addition of new fast-response technology. Grattan notes that prices in Queensland and South Australia have fluctuated dramatically even when demand is moderate and relatively stable, and that this indicates price changes are

12 ACCC, *Restoring electricity affordability and Australia's competitive advantage*, https://www.accc.gov.au/publications/restoring-electricity-affordability-australias-competitive-advantage, 11 July 2018.

13 Grattan Institute, *Mostly working - Australia's electricity market,* July 2018, p. 45.

14 ibid. p. 33.

15 ibid. p. 33.

16 ibid. p. 34.

17 ibid. p. 34.

due to gaming rather than supply shortages. It does not consider the five minute rule will incentivise new investment to eliminate such gaming, unless the new generator's long run marginal cost is lower than the market price without gaming.

3 ASSESSING GRATTAN'S ANALYSIS

Wholesale energy costs in the NEM increased significantly between 2015 and 2017, driven by a number of factors including generator retirements and higher fuels costs. Consumers felt the impact of these changes through increases in the retail price of energy between 2017 and 2018.

Much of the Grattan report adds to the recent body of work, including more recent work by the ACCC and work previously done by the Australian Energy Regulator (AER), in relation to the causes of increases in wholesale energy costs. It comes to similar conclusions as to the solutions to the problem. This assessment, however, relates only to the component of the Grattan report addressing the issue of gaming and the component of wholesale costs Grattan attributes to gaming.

There are a number of dimensions to this assessment, including:

- that Grattan's definition of gaming is too broad, this inadvertently labels instances of volatility and rebidding as gaming
- the AER's analysis of the causes and cost of the gaming instances identified by Grattan shows that rebidding is only one of a range of factors that cause price spikes
- an estimation of the cost of price spikes, driven by rebidding, shows that this is a minor and falling component of the consumer's overall bill.

Chapter 4 highlights the beneficial role of rebidding in the pre-dispatch process, and how it provides for efficient pricing outcomes in the short term and efficient investment outcomes in the longer term.

3.1 The defintion of gaming is too broad

The Grattan report identifies a trading interval as an instance of gaming if the difference between the price in the two most expensive dispatch intervals is greater than the price for the trading interval. This definition identifies instances of price volatility, but it is not necessarily indicative of gaming. Grattan acknowledges with this definition that "some genuine supply constraints may be captured" by the definition but "some gamed intervals are also likely to be excluded".[18]

In the Commission's view it is important:

- to understand the causes of wholesale price volatility rather than assuming all instances indicate gaming. The causes associated with the price spikes identified by Grattan are assessed in section 3.2. The Commission has worked with the AER to analyse more granular data in regards to the causes of price spike events in order to assess the $825 million cost identified.
- to recognise the benefits of rebidding in delivering efficient pricing and investment outcomes, and to distinguish between legitimate market dynamics and gaming.

18 ibid. p. 26.

3.2 Rebidding is only one of a range of factors causing price spikes

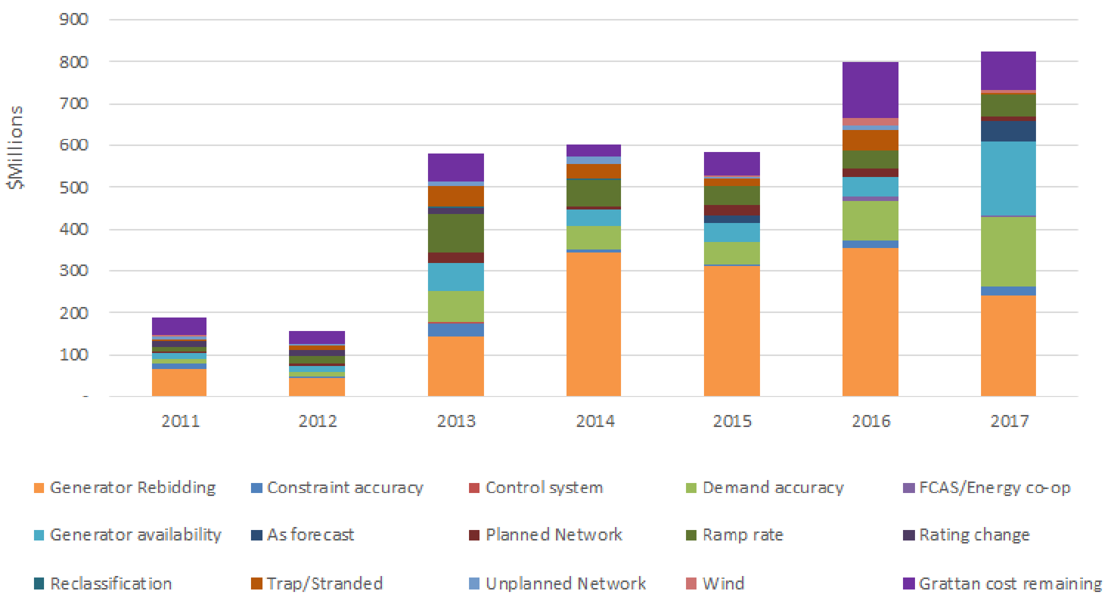
Under clause 3.13.7(a) of the National Electricity Rules, the AER is required to monitor the wholesale electricity market and to report on instances where there is a significant variation between forecast and actual spot prices.[19] Where such differences are identified, the AER must review the reasons for the variation and identify the primary cause of this variation. The AER has a broad range of categories for understanding such instances, including generator rebids, forecast accuracy and generator availability. Appendix A provides a list of the definitions of all the categories used by the AER in this analysis.

To analyse the claims of market gaming, the Grattan definition of a gaming incident was used, and those trading intervals matched against the AER's events register. The events register captures trading intervals in which the spot price is greater than $250 per MWh and three times the seven day average or the spot price is below -$100 per MWh. In this way, in 2017, $732 million of the $825 million calculated by Grattan to be instances of gaming were identified.

Figure 3.1 (below) shows the cost of the trading intervals matching Grattan's analysis, split by the primary contributing factors for the wholesale price spike as determined by the AER. Generator rebidding, far from being the only cause, is shown to be one of fourteen potential causes for the price spike events. It also shows the "Grattan cost remaining" in purple, which represents the cost of the trading intervals with prices that did not trigger an AER analysis and reporting requirement. Appendix B provides the same breakdown for each region in the NEM.

19 AER analysis of Grattan price spike events uses the AER Events Register which records significant price variations in the NEM. A significant price event is defined either as a spot price greater than $250/MWh and three times the seven day average or a spot price below -$100/MWh.

Figure 3.1: Grattan rebid cost by primary cause (NEM-wide) using AER events register



Source: AER

In 2017, the AER data shows that generator rebidding was the single most likely cause of price variations with a cost of $243 million. Most of this, $214 million, occurred in Queensland (see Figure 5.2 and section 5.4 for further analysis). The next most significant factors, demand accuracy and generator availability, contributed a combined $344 million to the cost.

Importantly, the more granular AER data shows that the cost associated with rebidding was lower in 2017 than in the previous three years. This is contrary to the claims of Grattan that there has been an increase in the cost of gaming related to rebidding since 2015.

The cost of other drivers, such as demand accuracy and generator availability, increased by $246 million from 2015 to 2017. Factors such as ramp rates have been relatively consistent since 2014 at an average of $50 million per annum.

3.3 The cost of price spikes and rebidding

In 2017, the cost of price spike events, in which rebidding was the cause, represents only one per cent of the wholesale cost of energy in the NEM. This cost, however small, is highly unlikely to be borne by consumers. Retailers typically enter into hedge contracts to prevent such wholesale price volatility being passed onto consumers in the form of higher retail prices.

While high or volatile wholesale prices in the NEM can be expected to flow through to future wholesale contract prices and therefore the cost to retailers of hedging their consumer load in subsequent periods, this is not a direct one-to-one relationship. The wholesale portfolios of retailers tend to be fully hedged for at least one year and possibly two years ahead. Future wholesale hedging costs will depend on many factors. This includes recent wholesale price levels and volatility, but also expectations for future wholesale prices and volatility and investment in new generation assets.

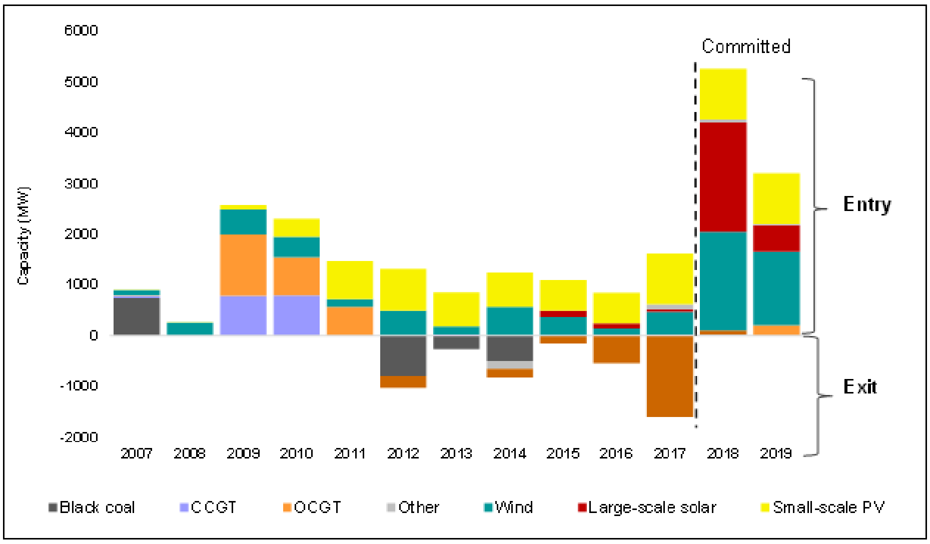
3.4 Investment in new generation assets in the NEM and impact on electricity prices

Periods of high and volatile wholesale spot prices in the NEM, such as have been experienced in recent periods, creates a signal that incentivises new generation investment. New generation investment helps to drive wholesale costs lower in ensuing periods.

Figure 3.2 highlights that in the past year there has been a significant level of new investment in generation. 2019 is set to see a similarly large amount of new generation enter the market. Assuming all committed generation projects proceed, there will be over 6,000 MW of capacity installed in the NEM across 2018 and 2019.

This new capacity will lower wholesale prices in the short term. In the 2017 Residential electricity price trends report,[20] the Commission highlighted a likely fall in wholesale electricity costs and consumer bills over the two financial years 2018/19 and 2019/20 as more wind and solar generation comes online, offsetting increases seen in the previous financial year. The nature of the capacity installed will determine the longer effect it has on wholesale prices.[21]

Figure 3.2: Entry and exit of generation capacity in the NEM, 2007 to 2019



Source: Endgame Economics, AEMO data

20 AEMC, *2017 Residential electricity price trends report*, https://www.aemc.gov.au/news-centre/media-releases/electricity-prices-estimated-to-fall-over-next-two, December 2017.

21 AEMC, *2017 Residential electricity price trends report*, p. iv-v.

4 THE ROLE OF REBIDDING IN DELIVERING EFFICIENT MARKET OUTCOMES

At any point in time, the supply and demand for electricity must be in balance. AEMO achieves this by dispatching the required quantity of generation to meet demand every five minutes. In order to know what quantities of generation and demand are available at different price points, AEMO relies on the pre-dispatch process.

This section describes:

- the interaction between the wholesale, contract and retail markets
- the pre-dispatch process
- the incentives on participants in the process
- the process of rebidding
- how rebidding facilitates efficient pricing and investment outcomes.

4.1 Interaction between the wholesale, contract and retail markets

The wholesale market for electricity determines the prices and quantities generated and purchased every trading interval in every region of the NEM. However, the wholesale cost of electricity is not the product of these quantities and prices but is driven largely by the outcome of contracts struck between generators and retailers. The prices for electricity paid by retailers to generators in these contracts smooth the costs and revenues associated with the much more volatile wholesale prices determined in the spot market.

The most common form of contract is a "swap". The simplest form of swap contract is one where a retailer agrees to pay a generator a fixed price for an agreed quantity of electricity (i.e. swapping the volatile wholesale price for a fixed price). This swap contract hedges the retailer against high wholesale prices and the generator against low wholesale prices and smooths the costs and revenue of both parties. Another common contract is a cap, which insures a retailer against wholesale prices above a specified threshold, typically $300 per MWh.

These wholesale contracts affect:

- how generators operate in the short term and are therefore important for the day-to-day operation of the power system
- provide, in the longer term, cost and revenue certainty for retailers and generators and price certainty for retail customers.

Typically, because the wholesale price is fixed under a swap contract, generators are incentivised:

- to bid to be dispatched for the quantity they are contracted for
- to hold and bid generation capacity in excess of their contract quantities.

This implies generators will often not be contracted for their full generation capacity. This is an effective risk mitigation strategy and is illustrated in the example in Box 2.

The example shows that rebidding supports a generator's ability to meet their contractual commitments in the event of unforeseen changes to their availability or market conditions. This flexibility enables generators to manage the operational and financial risks associated with providing long term contracts. The combined role of the forward contract market and rebidding reduces the financial risks associated with wholesale market volatility, provides more efficient operation of the power system, and supports reliability by encouraging generation to be held in reserve.

Outcomes in the wholesale spot market generally do not impact on *current* consumer prices and bills because wholesale prices are agreed in advance in contracts between retailers and generators. The price of wholesale contracts struck today for electricity consumed in, say 2020, is based on expectations of wholesale prices at the time. If demand and supply for electricity is expected to be tighter in 2020, wholesale prices are likely to be higher, on average, and wholesale contract prices will also be higher (all else being equal). Consequently, higher spot prices now will only cause wholesale contract prices and consumer bills to rise if they were unexpected and cause expectations about future wholesale prices to rise.

4.2 The pre-dispatch process

The pre-dispatch process provides AEMO and market participants with schedules of generation and demand for five-minute dispatch intervals in the following hour and for thirty minute trading intervals up to a day and a half in advance.

The schedules contain bids from scheduled generators (to supply) and loads (to consume), and forecasts of generation and consumption for which individual bids are not required (see Box 1 for definitions of different participants). The schedules are regularly updated with new information submitted by participants, network operators and AEMO. This provides information to guide participants in their generation or consumption decisions until the time of dispatch.

Each pre-dispatch schedule is determined by AEMO's National Electricity Market Dispatch Engine (NEMDE) software.[22] NEMDE calculates the least cost mix of generation to meet demand from the available bids for scheduled generation and load, and from forecasts of semi-scheduled and non-scheduled generation, demand and network limits for each interval.

BOX 1: THE DIFFERENT TYPES OF PARTICIPANTS AND THE INFORMATION THEY PROVIDE IN PRE-DISPATCH

Scheduled generators arenon-intermittent generating units greater than 30 MW. They are required to submit offers specifying their generation intentions, and must comply with dispatch instructions issued by AEMO. Batteries above 5 MW need to register as a scheduled generator or will be subject to equivalent requirements via their licence conditions.

22 NEMDE is AEMO's software for determining the price and quanity of generation in the NEM for each dispatch and trading interval.

Semi-scheduled generators have variable energy sources such as wind and solar and have a generating capacity above 30 MW. AEMO forecasts their generation via wind and solar forecasting models. These generators then specify prices for their generation. AEMO can require them to limit their output if required.

Non-scheduled generators may be intermittent or non-intermittent and generally have a nameplate capacity between 5 MW and 30 MW. They are not required to provide information on their generation intentions. AEMO forecasts the output from this category of generators and generally does not constrain their output.

Exempt generators are intermittent or non-intermittent generating units less than 30 MW that do not participate in central dispatch. AEMO forecasts the generation of this category, and does not constrain their output.

Scheduled loads are controllable quantities of electricity consumption that can place bids specifying their consumption intentions, and must comply with dispatch instructions issued by AEMO. Batteries above 5 MW are required to register as a scheduled load.

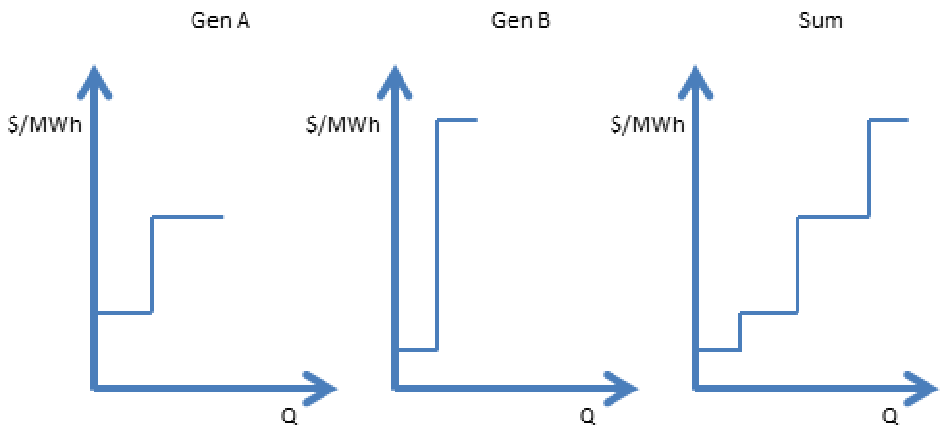
Other market loads are not required to be scheduled and the market participants (retailers and consumers) concerned are not required to provide information on their expected demand for electricity. AEMO forecasts the demand from this category of participant.

Source: AEMC

A generation bid conveys a willingness to generate electricity if the spot price is equal to or above the bid price. A generator could submit a bid to generate 30 MW if the wholesale price is at or above $30 per MWh, another 20 MW if the wholesale price is at or above $100 per MWh, and another eight quantity and price pairs, such that the total quantity sums to the available capacity of the generating unit.

Figure 4.1 (below) illustrates how bids from two generators (Gen A and Gen B) are added together to form a generation bid stack (sum). AEMO dispatches the bids required, from the cheapest on the left to most expensive on the right.

Figure 4.1: Diagram showing how generation bids sum to form a supply stack



Source: AEMC

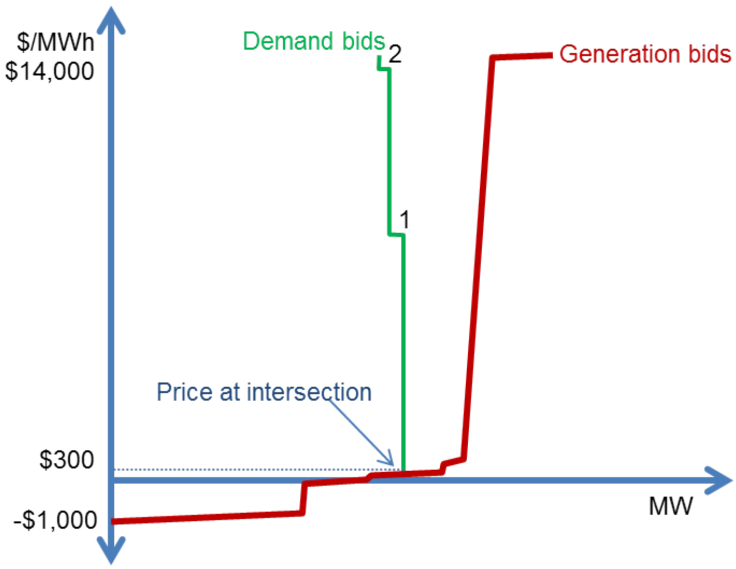
A load bid conveys a willingness to consume electricity if the spot price is below the bid price. The bid price can be high or low depending on how often the consumer needs to use electricity. An industrial consumer could submit a bid to use 15 MW while the spot price is below a relatively high level (e.g. $10,000 per MWh). This indicates the consumer would rarely wish to stop using electricity. Alternatively, a consumer could submit a bid to use 15 MW only when the spot price goes below a relatively low level (e.g. $0 per MWh), indicating the consumer only wishes to use electricity occassionally when prices are very low.[23]

The pre-dispatch schedules show participants the forecast outcome of participant bids and market forecasts. Participants can see the regional reference prices and the quantities of their own generation and scheduled loads. They do not see the quantities of other generators or loads.

Figure 4.2 (below) illustrates how the generation and demand bids provide demand and supply curves and the price in a NEM region. The generation bids in red include generation that is priced below $0 per MWh to ensure it is nearly always dispatched and generation near the market price cap and everything in between. The demand bids in the figure are limited to two large customer loads (labelled 1 and 2), willing to be curtailed at relatively high prices.

23 Currently, AEMO's list of scheduled loads contain one aluminium smelter, three hydro pump storage units and one large battery facility.

Figure 4.2: How bids sum to provide demand and supply stacks and price



Source: AEMC

4.3 Bidding incentives and strategies

Generators have an incentive to bid their capacity at prices below their competitors because they earn revenue only by bidding at prices low enough to be dispatched by AEMO. If a generator is not dispatched, it does not earn revenue from the wholesale spot market.

The extent to which generators are willing to lower their bid prices to be dispatched to generate electricity is limited by their costs. In the short term, a generator will at least want to cover the actual expenditure incurred while generating electricity, such as fuel costs. These costs are known as variable costs because they vary with output. They also form the basis for calculating the short run marginal cost. Over time, in addition to variable costs, generators need to recover costs that do not vary with output, such as operating overheads, maintenance costs, depreciation and an adequate return on capital investment. These costs are known as non-variable or fixed costs because they do not vary with output in the short term. Over time, generators need to recover their total costs (variable and fixed), in order to remain in business.

The ability of a generator to recover these costs from the wholesale market depends on their bidding strategy and the bids of their competitors. Bidding strategies are tailored to how their variable and fixed costs compare to their competitors and by the operational flexibility of the plant; i.e. how fast it can ramp up or down, turn off or on, and the associated costs. Bidding strategies, as outlined in section 4.1, are also effected by the contract position of the generator.

A relatively inflexible generating unit with slow ramp times (e.g. a coal-fired generating unit) may be unwilling or unable to turn on and off during the short and relatively rare times when wholesale prices are lower than their variable costs. This generator could choose to bid at least a portion of the generating unit's output at prices low enough to ensure they are dispatched all the time. This strategy results in the generating unit making losses as it would continue to generate electricity in trading intervals when prices are below its variable costs.

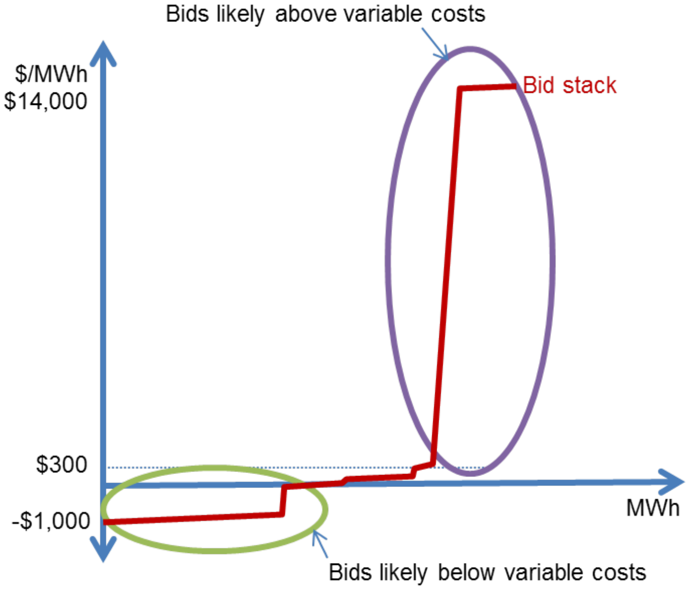
The generator employing this strategy hopes to more than make up for these losses in the other trading intervals when wholesale prices are higher than their variable costs. Generators in this situation can reduce the risk by selling at least a portion of their output in the contract market at a fixed price, which can then be bid at a price low enough that it is always dispatched. Figure 4.3 below shows the loss-making bids in the lower half of the generation bid stack that are employing this strategy, a large proportion of which are likely to be receiving contract prices for their generation.

A more flexible generating plant, with high variable costs (e.g. a gas-fired open cycle generating turbine), would not employ this strategy if wholesale prices are lower than its variable costs most of the time. Instead, it could bid its capacity at prices higher than variable cost so that it makes a contribution to non-variable costs whenever it generates. As illustrated in the second example in Box 2, generators in this situation can also reduce the uncertainty in their revenue by contracting with parties that are exposed to spot prices. Figure 4.3 shows the bids in the upper half of the generation stack that are indicative of this strategy, some of which are contracted with retailers to generate when prices are greater than $300 per MWh (cap contracts) as indicated by the notch in the bid stack at this price.

Whatever strategy they employ, the generator needs to take account of the actions of other participants so they are dispatched in enough trading intervals to meet minimum revenue requirements over days/weeks/months to cover all the generator's costs and its contract position.

The pre-dispatch bidding process enables participants to signal their intentions in advance, to monitor the intentions of their competitors, and then to make adjustments to their bids in order to meet these operational and financial requirements.

Figure 4.3: Generation bid stack showing different bidding strategies



Source: AEMC

4.4 The rebidding process

After making their initial bids, market participants can rebid to reflect changes in their intentions at any time.[24] Rebidding provides generators and loads with the flexibility to adjust their plans in response to changing market conditions and the bids of other market participants.

There are many reasons a market participant may consider making a rebid. For example, it may receive new or updated information regarding:

- changes in forecast demand
- unexpected changes in the output of variable renewable generation (e.g. wind forecasts)
- changes in the capability of a generating unit or its fuel supply (e.g. thermal limits, plant outages)
- changes in the expected demand of a large consumer
- the appearance/disappearance of network congestion
- changes in the bids of other participants.

The market participant would then weigh that information against a series of factors relevant to its business, such as:

- their estimation of future spot prices

24 There is a delay of about a minute for a rebid to be processed and ready to be dispatched.

- their sold contractual position and their potential losses on their financial contracts if they are not generating when the spot price is high
- their ability to ramp up generation to capture high spot prices and to minimise generation to avoid spot prices below cost
- any fixed costs associated with starting and stopping units, as well as the costs associated with running the units at different output levels, for example, at minimum output.

Rebidding is therefore an iterative process by which generators and loads regularly update their bids to signal changes in their intentions to generate or consume electricity.

Unusually high or low forecast spot prices provide incentives for generators to rebid, but their ability to respond depends on the flexibility of their assets, in particular the speed they can turn their generators on or off, or ramp their generation up or down. Participants with less flexible assets (e.g. coal fired generators) necessarily have a longer rebidding time horizon than those with more flexible assets (e.g. batteries).

4.5 How rebidding supports more efficient wholesale prices and investment

An efficient electricity market will deliver reliable power at the lowest cost to consumers. Efficient outcomes are achieved in the short term when electricity is:

- provided by generators that produce at the lowest cost (productive efficiency)
- consumed by those that value it most highly (allocative efficiency).

To achieve efficient outcomes in the long term (dynamic efficiency), it is necessary for there to be sufficient and timely investment in generation capacity and demand side technologies.

4.5.1 Short term pricing efficiency

In the short term, rebidding incentivises and enables the most efficient mix of generation to be dispatched, and efficient consumption decisions to be made.

For generators, the market information made available in the pre-dispatch process supports rebidding and alters the prices and generators dispatched. This process should minimise the costs of electricity production, depending on the degree of rivalry in the market.

At any point in time, the level of competition between market participants determines the degree of downward pressure on wholesale prices. The pressure is greater at times when there are more competing generators and more available generation, but the pressure eases as demand approaches the limits of the generation available. As demand increases and the number of generators and the remaining available generation decreases, generators have a greater opportunity to be dispatched at bid prices higher than their variable costs.

For consumers, the information made available in the pre-dispatch process can help them decide efficient levels of consumption. This is particularly relevant for large commercial and industrial consumers who may have exposure to wholesale market prices 'at the margin', even if they sign contracts that hedge some or all of their exposure.

Dispatch prices in the NEM support productive and allocative efficiency when, at the market price, no generator is willing to generate more or less electricity and when no consumer is willing to consume more or less electricity.

While it receives much more attention for causing price spikes, rebidding results in lower price outcomes (compared to the pre-dispatch forecast) in almost as many instances as it results in higher prices. The two examples in Box 2 illustrate the value of rebidding in lowering prices either in relation to unplanned outages in generating plant or changes in market conditions.

BOX 2: THE VALUE OF REBIDDING IN LOWERING PRICES

Rebidding in response to an unplanned outage

A generator operates a 400 MW coal plant comprised of four 100 MW units. The generator has a low operating cost (short run marginal cost or SRMC) at optimal output levels of 75 MW for each unit or 300 MW in total. To cover its costs and to provide some revenue certainty the generator sells a forward contract for 300 MW. The generator receives the strike price in the contract for the 300 MW even when spot prices are below the strike price. The generator pays the buyer the difference between the spot price and the strike price for the contracted quantity if the spot price is higher than the strike price.

The contract encourages the generator to bid so that it is dispatched for at least 300 MW of its 400 MW capacity when spot prices are higher than its operating costs. Consequently the generator bids 300 MW into the market at or below $50 per MWh (the generator's SRMC in this example). The balance of capacity, 100 MW, is bid into the market at prices above $300 per MWh, far higher than prices forecast in pre-dispatch schedules.

At 12:55pm, the generator has been dispatched for 300 MW. The price of electricity is $60 per MWh and pre-dispatch forecasts suggest it will remain at or above this level for several hours. At 12:57pm, one of the generator's units unexpectedly trips and can only be restarted after a period of several hours, so the generator rebids the unit as unavailable. Forecast prices are now expected to be high.

If the generator does not change its bids for the other units then at 1:00pm, AEMO will dispatch it to generate 225 MW and prices in the region will increase to over $300 per MWh for several hours. This motivates the generator to restore its output to 300 MW as soon as possible to cover the expected costs it will otherwise incur from its contract (this cost is the difference between the spot price and the strike price applied to the shortfall in the generator's output against the forward contract). It rebids the 75 MW available from the three remaining units (25 MW per unit) into the low price bracket so that 300 MW of capacity is dispatched until the fourth unit is ready to be returned to service. As a result of the rebid, prices in the region fall to $60 per MWh and are forecast to remain at this level for several hours, as before.

This example demonstrates the importance of rebidding as a mechanism for individual participants and the market as a whole to adjust in response to sudden and unexpected events. It shows how important rebidding is for participants to manage their operational risks and financial exposures and how late rebidding can result in lower prices in the wholesale market.

Rebidding in response to changing market conditions

In this example, a peaking gas generator that operates infrequently and faces significant startup costs is capable of generating 20 MW of electricity, has a startup cost of $2,000 and an operating cost or SRMC of $250 per MWh. This type of generator adjusts its bids in response to expected prices and forecast dispatch quantities and may find it efficient to rebid late. The generator would prefer to be dispatched during price spikes that enable it to recover its startup costs. As a result the generator bids all of its capacity at a price of $12,000 per MWh.

At 08:00am, the generator's view of future prices is that there is a likelihood of a single-interval price spike reaching $12,000 per MWh during the day. For the remainder of the day, prices are expected to average $80 per MWh. Even if the price spike occurs, the generator expects that it will only be dispatched for a limited portion of its capacity for a single five minute dispatch interval. It closely monitors pre-dispatch schedules because it knows it will have to rebid at a higher price to avoid being dispatched if conditions don't change.

However, market conditions change so that high prices are forecast to last for longer. At 10:00am, the generator notices that forecast prices in pre-dispatch have changed and are now forecast to be high over a sustained period of time. These changes in pre-dispatch can be driven by such things as demand changes, generator availability and transmission constraints. The generator now expects prices to rise from $300 per MWh to $3,000 per MWh between 10:05am and 11:00am, and remain around this level until 1:00pm. Prices are expected to remain at $8,000 per MWh for two hours or 36 dispatch intervals.

As a result, at 10:02am, the generator rebids its 20 MW capacity at $250 per MWh for the period 10:05am to 1:00pm. It does this as it expects prices will be high enough to ensure continuous dispatch from 10:05am to 1:00pm. Startup costs can easily be recovered over the two-hour period of operation from 11:00am to 1:00pm in which prices will be $3,000/MWh. As a result of the generators rebid the price over the period 10:05am to 1:00pm is lower than it would otherwise have been, given the generator is willing to offer energy into the market at the lower price of $250 per MWh as opposed to $12,000 per MWh.

The high variable and startup costs of this type of generator make it necessary and efficient for generators to be able to rebid capacity to signal changes in a willingness to generate in response to a change in expectations of future prices and dispatch quantities.

Source: AEMC

4.5.2 Longer term investment efficiency

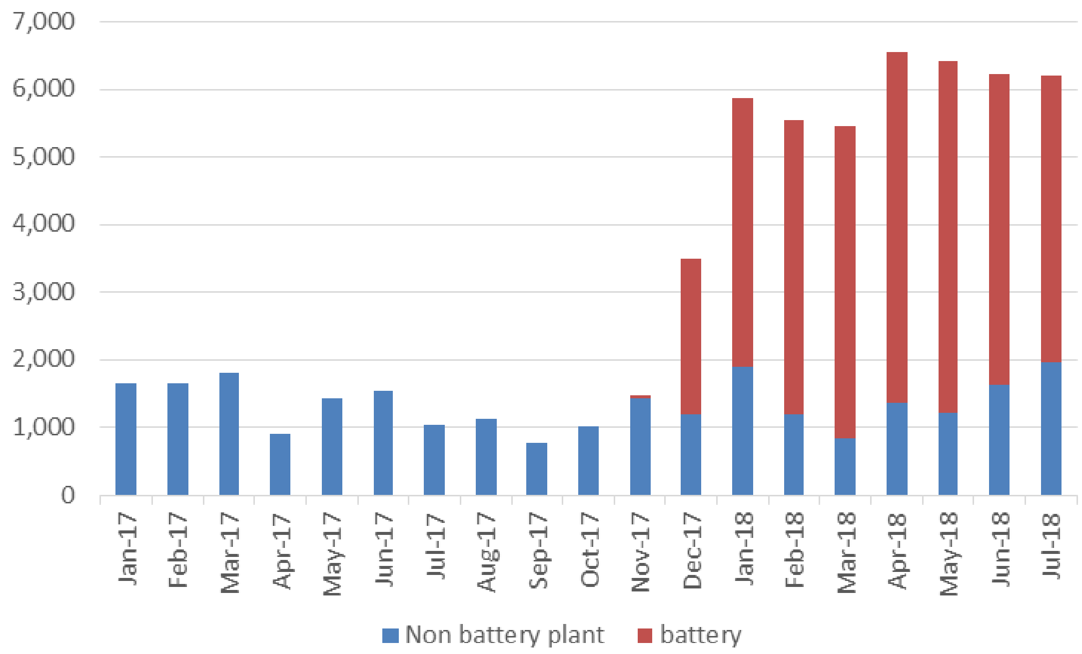
The process of rebidding also indirectly supports efficient investment decisions. Efficient wholesale prices provide the best signal for investment, both in the quantity and type of generation capacity or demand response needed over time. These investment decisions are influenced by the ability of resources to respond quickly to changing spot prices and market conditions. A period of spot price volatility provides potential investment opportunities for fast start generation, demand response and storage facilities that can respond rapidly to changing prices. Similarly, retailers are incentivised to enter into contracts for this type of capacity. The degree to which these opportunities translate into new investment depends on the degree of competition, the cost of generation and the extent of any barriers to entry.

Investment in fast start generation and battery technology to take up the opportunities of greater spot price volatility are likely to rebid more often than traditional generation technology. Frequent rebidding close to the point of dispatch allows these sources of supply (and consumption) to rapidly respond to changing market conditions and signal their value to the market.

For instance, the Hornsdale battery, commissioned in South Australia in mid-November 2017, is the first large scale commercial example of battery technology operating in the NEM. The operation of the battery has significantly increased the incidence of late rebidding in South Australia since it began trading in December 2017 (see Figure 4.4 below), and is widely credited with reducing Frequency control ancillary service (FCAS) prices in that jurisdiction. The battery uses custom software to constantly review and respond to actual or forecast changes in the market, without manual intervention. As such, rebidding is not a sign of gaming, but rather the continuous revaluation of the energy stored against the regularly updated price forecasts in the market for future trading intervals.

The Commission expects to see further participants adopting this approach as more batteries and other flexible technologies participate in the NEM and when five minute settlement commences in July 2021.

Figure 4.4: Late rebidding in South Australia showing contribution by Hornsdale battery



Source: AER

5 ANALYSIS OF GRATTAN'S PROPOSED MARKET DESIGN CHANGES

The preceding analysis does not support the case for making market design changes to the rebidding rules.

The analysis indicates that generator rebidding is one of a number of causes of price spikes, that rebidding can lower wholesale prices as well as increase them, and its impact on customer bills is not material. Further, rebidding is an important mechanism for facilitating pricing and investment efficiency.

Notwithstanding these findings, the Commission has considered Grattan's views on the solutions to prevent gaming, including:

- the introduction of a gate closure mechanism
- the shortcomings of the *Bidding in good faith* and *Five minute settlement* rule changes
- other proposed solutions, namely a day ahead market, a pivotal supplier test, and increased demand response.

Grattan's other recommendation to split the two Queensland government owned generators into at least three is discussed in section 5.4.

5.1 Gate closure

Grattan proposed the introduction of a gate closure mechansim with the following characteristics:

- late rebids (within thirty minutes of dispatch) that lower prices would be allowed
- late rebids that raise prices would have to be justified to the market operator. If the justification were deemed inadequate, the generator would face a financial penalty.

Given the AER analysis showed many price spikes were caused by factors other than rebidding, a gate closure mechanism would not be effective in addressing these causes. Nevertheless, this section considers the overall merits of Grattan's proposed form of gate closure as a method for resolving issues related to late rebidding.

5.1.1 Trade-offs associated with limiting late rebidding

The Commission considered gate closure as a potential solution to some of the issues associated with late rebidding in the *Bidding in good faith* rule change.

The Commission decided that instituting gate closure would trade one type of efficiency for another. Specifically, gate closure:[25]

- may improve efficiency by preventing participants from intentionally rebidding late without cause, in breach of the National Electricity Rules (NER);

25 AEMC, *Bidding in good faith*, Final Determination, https://www.aemc.gov.au/sites/default/files/content/815f277c-a015-47d0-bc13-ce3d5faaf96d/Final-Determination.pdf, 2015.

- may diminish efficiency by preventing market participants from responding to changes in market conditions close to dispatch.

The Commission acknowledged that some late rebids may not be efficiency enhancing where the information revealed in the rebid had been withheld so that other participants did not have time to respond. This behaviour is against the NER, but potentially can happen and is difficult to detect.

However, rebidding close to dispatch is also an important way in which generators can effectively manage risk as noted in Chapter 4. There are significant efficiencies associated with allowing participants to rebid. For example, rebidding can occur to manage the supply demand balance in response to a generator tripping or in response to congestion-related dispatch risk.

It may also be efficiency enhancing for generators to rebid some of their output into a higher price band when it signals the value of scarce generation. When these events occur repeatedly, they can provide a price signal for new investment, be it in generation, transmission, storage or demand response.

Beyond the effects on efficiency, a gate closure mechanism has the following two weaknesses:

- it does not prevent late rebidding – it simply shifts the deadline for late rebidding forward
- a gate closure mechanism is not competitively neutral.

During the *Bidding in good faith* rule change, several stakeholders identified that gate closure does not remove the potential for generators to rebid so late that other generators cannot respond. Instead of bidding immediately before the dispatch interval, generators can simply rebid immediately before the gate is closed. Gate closure therefore does not prevent the type of behaviour that Grattan has identified. Instead, it brings forward the timing of any late rebidding.

A gate closure mechanism is also distortionary. It provides non-scheduled generation and demand response with a competitive advantage over scheduled and semi-scheduled generators. Non-scheduled generation and demand-side response can respond to pre-dispatch prices right up to dispatch, while scheduled and semi-scheduled generation would be locked into the bids they submitted prior to the gate closure.

For these reasons the Commission remains unconvinced that the advantages of a gate closure mechanism outweigh its disadvantages, and it does not consider gate closure to be an appropriate and proportionate response to the highlighted issues.

5.1.2 Specific issues with Grattan's gate closure proposal

In addition to the issues noted above, Grattan's proposed asymmetric gate closure model may distort incentives for generators to bid in good faith in pre-dispatch and thereby diminish the value of pre-dispatch as a signal to the market.

If the proposed gate closure were implemented, generators would have an incentive to over-bid in pre-dispatch. This would allow them to rebid their capacity into lower price bands after gate closure. Such a strategy would preserve their ability to rebid late in order to be dispatched, but it would undermine market confidence in the signals provided by the pre-dispatch process. If this occurred, then pre-dispatch forecast prices would tend to be higher than the prices that eventuate at dispatch.

Another key issue with the Grattan proposal is for a 30 minute gate closure. The issue Grattan identified in its analysis was the mismatch between the time required by generators to respond to rebids, and the lateness of rebids. A 30 minute gate closure would not assist slower starting or slower ramping generators such as coal generators, and it would comparatively disadvantage generators with much faster response times, such as batteries. The risk in specifying any time is that it may distort competition between competing generation technologies.

5.2 Previous rule changes

The Commission has considered bidding rules, bidding strategies and bidding behaviour in the NEM at great length, both in the *Bidding in good faith* rule completed in December 2015 and in the *Five minute settlement* rule made in November 2017.

5.2.1 Bidding in good faith rule

The *Bidding in good faith* rule was implemented on 1 July 2016.[26] The Grattan report claimed it has not solved the problem of gaming[27].

Figure 5.1 (below) shows the incidence of rebidding in the NEM between 2011 and 2017, excluding the rebidding by the Hornsdale battery. The chart indicates:

- rebidding has risen steadily throughout the period from 210,382 in 2011 to 378,422 in 2017 (an 80 percent increase)
- while late rebidding increased until 2016, late rebidding as a proportion of total rebids fell from 48 percent of total rebids in 2015 to 42 percent in 2016 and 35 percent in 2017.

The Commission consider the *Bidding in good faith* rule is a more efficient way to address issues associated with rebidding than the type of 'hard' gate closure mechanism proposed by Grattan. In certain respects, the *Bidding in good faith* rule is a form of gate closure requiring justification for late rebids. The rule requires that:[28]

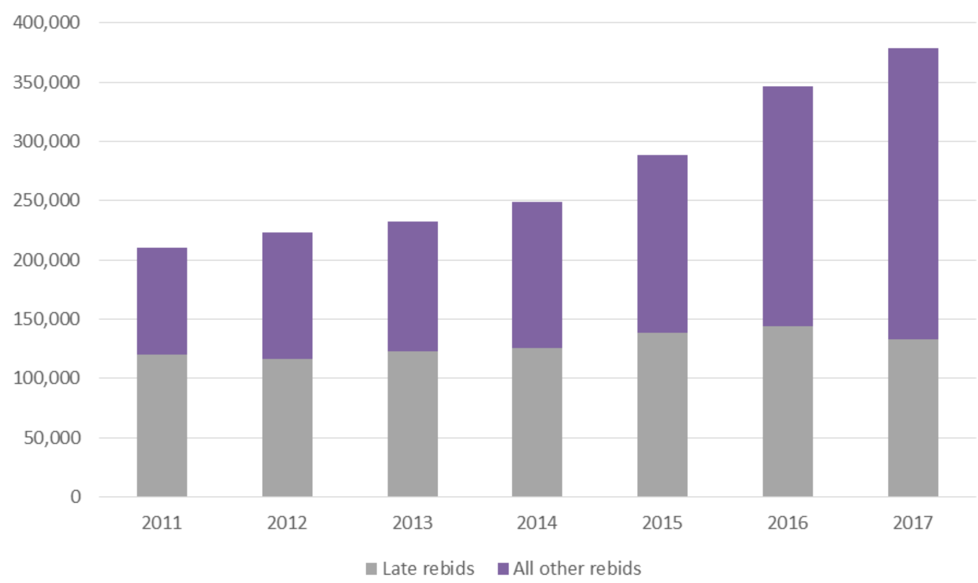
> *For each rebid made within the late rebidding period, the rebidding generator will need to make and keep a contemporaneous record including the material conditions and circumstances giving rise to the rebid, the generator's reasons for making the rebid, the time at which the relevant event occurred, and the time at which the generator first became aware of the event. The late rebidding period begins 15 minutes before the commencement of the trading interval to which the rebid applies, and ends at the end of that trading interval.*

26 AEMC, *Bidding in good faith* project page, https://www.aemc.gov.au/rule-changes/bidding-in-good-faith, 2015.

27 Grattan Institute, *Mostly working - Australia's wholesale electricity market*, July 2018, p.33

28 AEMC, *Bidding in good faith* rule, Final determination, 2015, p .vi.

Figure 5.1: Number of late rebids each year from 2011 to 2017



Source: AER
Note: Data excludes rebidding by the Hornsdale battery.

Contrary to the conclusion drawn in the Grattan report, late rebidding by generators is not on the rise, this is despite an increase in rebidding as a whole. Figure 5.1 above shows an increase in rebidding over recent years, but with a fall in the number of late rebids between 2015 and 2017.

New fast start technology, such as the Hornsdale battery, is more likely to rebid often, given its ability to respond rapidly to high prices. Figure 4.4 shows the most recent data from Hornsdale's rebidding in the South Australia wholesale market, demonstrating the importance of the rebidding process to new fast response technology.

With more flexible and fast response technologies in the future, such as batteries, there will be an increasing number of new participants and in particular, participants with the ability to respond rapidly to changing prices. This is likely to increase rebidding and late rebidding across the market, moderating high and volatile wholesale prices.

5.2.2 Five minute settlement rule

When the *Five minute settlement* rule is implemented in 2021 it will align the dispatch and trading intervals. This will prevent generators from benefitting from a high 30 minute price after a five minute price spike, exactly the kind of price event that Grattan has highlighted in their analysis.

The Grattan report outlines a number of the benefits with *Five minute settlement* including this one (see section 2.3). But Grattan also suggested the rule has limitations. It claims generators with pricing power will still be able to initiate price spikes in a dispatch interval and, if high prices are caused by artifical supply shortages, then new generation investment may not occur. As such, the five minute rule will not solve the problem of gaming.

The Commission agrees with the benefits Grattan outlines. It also considers the rule will lower average spot prices over time and encourage new investment. Fast start technologies will have a comparative advantage in the market under *Five minute settlement*, and the contract market will also support new investment. If long term contract prices reflect expectations of higher prices (including price spikes) then new investment will be able to secure financing regardless of market views as to whether high prices are a result of genuine or artificial scarcity.

5.3 Other proposed solutions for consideration

Day ahead market

The Grattan report identifies a day-ahead market as a mechanism that would reduce the incentive for generators to game the system through strategic bidding in the real-time market.

Grattan notes that a day-ahead market requires retailers and large businesses to request a certain quantity of electricity for the following day and generators are required to bid their available output.

This is similar to the way pre-dispatch works but the prices and quantities are financially settled (i.e. contracted) for the following day. Dispatch continues to occur as it does in the NEM but the real-time prices would only affect participants whose quantities varied from those settled in the day-ahead market. Given a large proportion of electricity would be financially settled a day ahead, there would be less incentive for generators to resort to late rebidding in the real-time market. Any late rebidding that did occur would increase the wholesale price of only a (small) proportion of all generation.

The AEMC considered the suitability of a day-ahead market, as the Finkel review[29] recommended, in its *Reliabilty frameworks review*. In the final report, the Commission noted that the NEM has many features that play a similar role to a day ahead market. In particular, the Grattan proposal to have financial commitments a day ahead already exists in the financial contracts that are struck between market participants.

However, it also indicated there may be benefits associated with facilitating shorter-term trading in the NEM i.e. a more European-style arrangement. These benefits include providing market participants with more options to manage price risk and for more price certainty. A benefit of increased price certainty is that it may facilitate increased demand response in the wholesale market. Therefore, the report recommended that AEMO undertake work to submit a rule change request to the Commission by the end of 2018 to implement a short-term forward market that would allow participant-to-participant trading of financial contracts closer to real time.

29 Finkel Panel, *Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future*, June 2017.

Pivotal supplier test

The Grattan report noted that several North American jurisdictions use a pivotal supplier test to limit the bid prices of generators when competition is weak. It suggested that AEMC should investigate whether such a test could help stop gaming in the NEM.

The report suggested the test would apply only when demand is very high or supply is severely constrained, such as when a transmission line is broken or a power station goes offline. In such situations, if AEMO can meet demand during that period only by sourcing electricity from a pivotal supplier, Grattan suggested AEMO could impose a price limit. The pivotal generator would then have to make its capacity available to the market for that period at the AEMO-imposed price.

According to the report, if designed correctly, a pivotal supplier test could prevent large generators exercising any short-term or transitory market power to rebid their generation and force up prices.

The pivotal supplier concept is similar to a rule change request the Commission received from the Major Energy Users (MEU) in November 2010.

The MEU identified that, during periods of high demand, some large generators have the ability and incentive to exercise market power to increase the wholesale electricity price. To address this perceived problem, the MEU proposed that:

- the AER should assess which generators in each NEM region have market power during periods of high demand and declare each of them to be a 'dominant generator'
- when regional demand exceeds the level at which a generator has been declared to be a 'dominant generator', the dominant generator would be required to offer all of its available capacity for dispatch at a price that does not exceed the administered price cap of $300 per MWh.

The Commission considered the matter extensively, publishing a consultation paper, a directions paper, holding a public forum and issuing draft and final determinations. In its final determination, published on 26 April 2013, the Commission decided not to make a rule in respect of the rule change request because it was not satisfied the proposed rule would contribute to the achievement of the National Electricity Objective (NEO).

The Commission maintained then, as it does now, that transient pricing power resulting in occasional spot price spikes is an inherent feature of a workably competitive wholesale market. It is only a concern if it occurs frequently enough and to a significant enough magnitude to lead to average annual wholesale prices above the long-run marginal cost (LRMC) of generation. LRMC is a measure of the workably competitive level of wholesale electricity prices, with actual prices expected to be above this level in some years and below in other years, reflecting supply and demand conditions at particular points in time.

The Commission considered that for the solution to be justified, high wholesale prices must be sustained above the LRMC beyond a time period within which new generation could reasonably be expected to enter the market. It evaluated the case for intervention in each region of the NEM but could not justify changing the market design at that time. The Commission also notes that the AER is currently conducting a review of barriers to entry and assessing the effectiveness of competition in the wholesale electricity market, and will be publishing its findings in its Electricity wholesale performance monitoring report in late 2018.

A pivotal supplier test might have been attractive to jurisdictions in the US (e.g. PJM, New York, New England) because they have capacity markets and the revenue from those markets is supposed to cover much of the cost of providing capacity sufficient to meet peak demand. In these markets wholesale prices should not be expected to increase much above the variable cost of generation.

Demand response

The Grattan report considers demand response mechanisms encourage competitive pricing and reliable supply. It notes that the Finkel review recommended that the AEMC investigate more substantial demand response mechanisms for the wholesale electricity market.

Wholesale demand response is a market-driven response used to change the quantity of electricity bought in the wholesale market in response to wholesale prices, or to help market participants manage their positions in the contract market.[30]

Demand response is not homogenous in terms of its flexibility and ability to react to changes in forecast prices. As with generation, different demand response participants have different capabilities to respond to changes in the market, and different response times. Therefore, only a portion of the available demand response capacity at any time would be able to respond to late rebids in the available time. However, slower reacting demand response may be able to indirectly affect price spikes associated with late rebids by alleviating some of the scarcity of supply if it is forecast in the preceding day either in AEMO's Short term projected assessment of system adequacy (STPASA)[31] or predispatch forecasts.

Grattan's view is also consistent with the ACCC's recommendations, that there should be changes in the market rules to enable more demand response in the wholesale market. The ACCC recommended that a mechanism should be developed for third parties to offer demand response directly into the wholesale market, building on the work undertaken in the AEMC's Reliability Frameworks Review.

In the final report of the AEMC's Reliability Frameworks Review the Commission recommended that:[32]

1. A voluntary, contracts-based short-term forward market be implemented that would allow participant-to-participant trading of financial contracts closer to real time. This will provide consumers with more opportunities to lock in price certainty and so engage in the wholesale market, varying their demand in response to changes in wholesale prices.

30 AEMC, *Reliability Frameworks Review*, Final Report, 26 July 2018, pp. 43-44

31 The STPASA is AEMO's short term projected assessment of system adequacy. It provides a view of the market seven days ahead of dispatch.

32 Appendix A of the Reliability Frameworks Review provides a detailed explanation of the AEMC's recommendations. The review is available at the AEMC's website: https://www.aemc.gov.au/markets-reviews-advice/reliability-frameworks-review

2. Demand response aggregators and providers should be recognised on an equal footing with generators in the wholesale market, so they can offer wholesale demand response transparently into the market.
3. Consumers should be allowed to engage multiple retailers / aggregators at the same connection point (multiple trading relationships). This will promote competition between retailers, support new business models for demand response and provide consumers with opportunities to engage in demand response with parties other than their retailer.

The Commission is currently considering the *Wholesale demand response mechanism* rule change request from the Public Interest Advocacy Centre, the Australia Institute and the Total Environment Centre.[33] The request seeks to enable better integration of demand side participation in the wholesale electricity market through the recognition of demand response on equal footing with generators in the wholesale market.

Greater quantities of demand response will reduce opportunities for gaming in the wholesale market. The ability of consumers with fast reacting demand response to manage their consumption costs will be improved, in particular after the *Five minute settlement* rule is implemented.[34]

5.4 Industry structure and market concentration

Concentration of generator ownership in Queensland has enabled particular generators to exercise market power and cause price spikes.

More generally, market participants may be able to exercise market power over a number of trading intervals where:

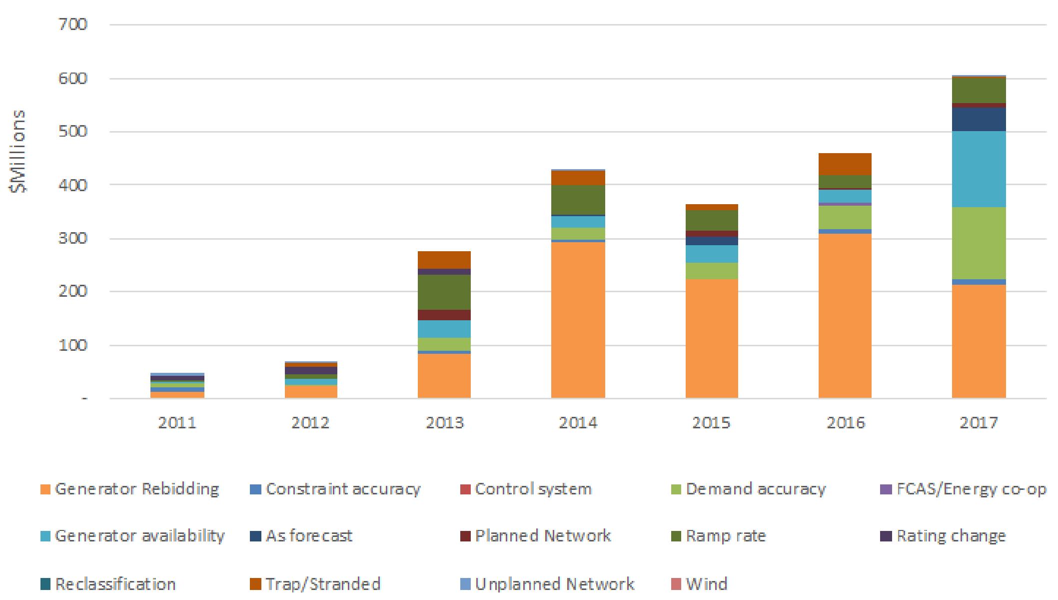
- they own a significant portion of generation capacity in a jurisdiction relative to the overall generation capacity and level of demand
- the location of their generators give them opportunities to influence interconnector flows during periods of high demand.

Further analysis of the price spike data for 2017 shows that, of the $243 million cost of price spikes attributable to generator rebidding, $214 million occurred in Queensland, and nearly all of this in January and February which was prior to the Queensland government's direction in June 2017 to Stanwell to moderate its bidding behaviour. The AER's causal analysis of Queensland is shown in Figure 5.2. Appendix B provides the same breakdown for each region in the NEM.

33 *Wholesale demand response mechanism* rule change request, 31 August 2018. Public Interest Advocacy Centre, Total Environment Centre, The Australia Institute.

34 This is because currently, in the event of a five minute price spike that occurs late in the 30 minutes trading interval, a load cannot retrospectively adjust its consumption that has already happened in previous five minute dispatch intervals. Once settlement is aligned with dispatch, a load capable of fast reacting demand response will be able to better manage the cost of its consumption.

Figure 5.2: Grattan rebid cost by primary cause (Queensland)



Source: AER

Grattan's analysis showed that price spikes, particularly to the market price cap, are more frequent in Queensland than in other regions, and the Queensland generation sector is particularly concentrated with two government owned corporations, CS Energy and Stanwell, controlling most of the energy generated.

The exertion of this market power is not through gaming behaviour, except where a breach of the rules is identified. Rather it occurs through the arrangement of bids in pre-dispatch and rebidding early enough such that other generators would be able to respond, if they had capacity available.

Grattan's analysis, and its conclusion to split the ownership of the Queensland government owned generators, was put forward ahead of the ACCC publishing its "Restoring electricity affordability and Australia's competitive advantage" report. The ACCC came to a similar conclusion to Grattan.

Market concentration in Queensland

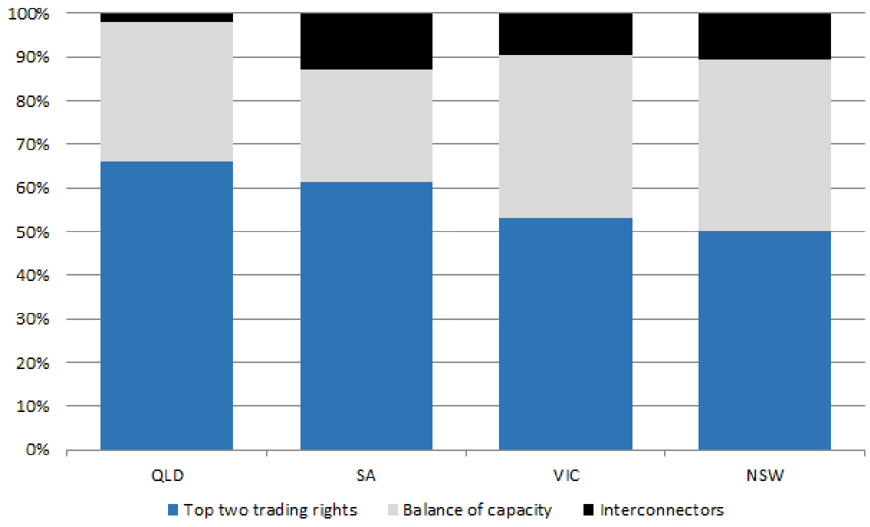
The Queensland market has the second-highest market concentration in the NEM, after Tasmania (Figure 5.3).[35] Stanwell and CS Energy control two thirds of scheduled generation capacity in the state,[36] even allowing for interconnection. South Australia has a slightly lower

35 Tasmania is excluded in this picture, given all generation in the state is owned by Hydro Tasmania

36 7,884 MW out of 11,966 MW scheduled generation and interconnector capacity, AER data, AEMC analysis.

level of market concentration while NSW and Victoria are both served by a wider range of participants and interconnector capacity.

Figure 5.3: Concentration in generator trading capacity (excludes Tasmania)

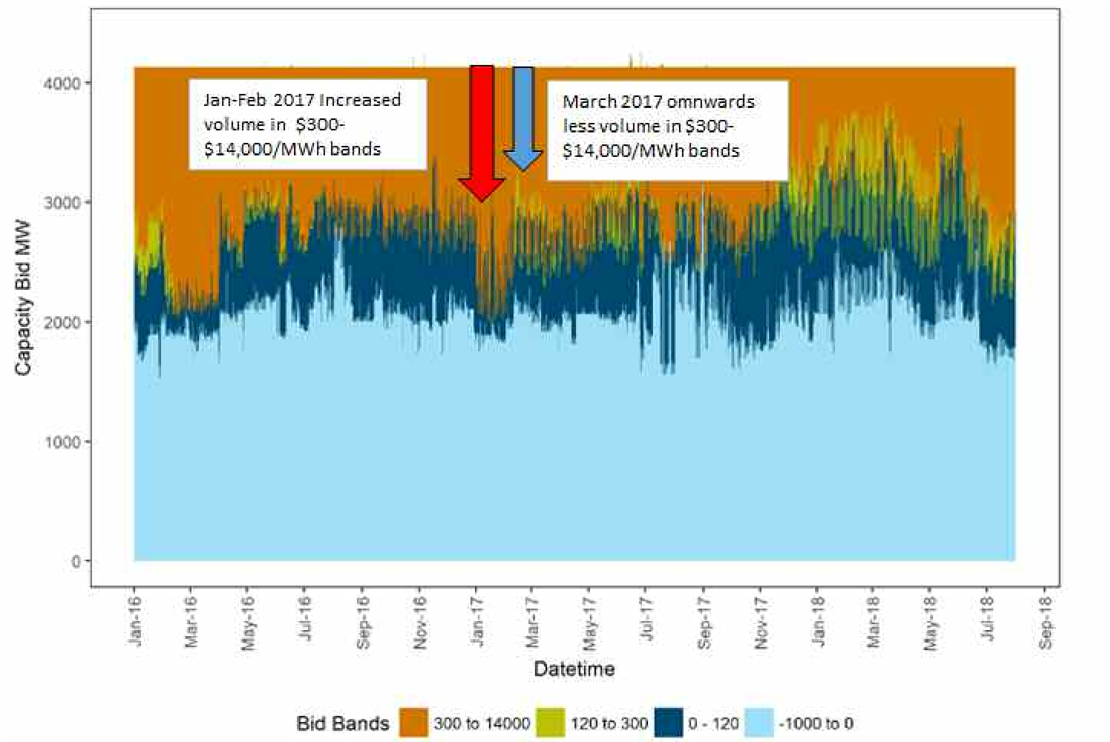


Source: AER data, AEMC analysis
Note: Excludes non scheduled generating capacity, includes interconnectors and reflects trading rights over capacity

This relatively high level of market concentration means that any change in bidding strategy and bidding behaviour by the two largest entities is likely to have a signficant impact on wholesale price levels in the market.

The bidding behaviour of Stanwell changed in the summer of 2016-2017, with tranches of supply moved from lower priced bands to higher price bands in January and February 2017. Following direction from the Queensland government in June 2017, the bidding strategy changed again, with spot and futures prices moderating after the direction was received. This is observable in Figure 5.4 below.

Figure 5.4: Stanwell bid price bands 2016-2018



Source: AEMC analysis of MMS database
Note: Bid bands combined into four categories

The Grattan report recommended that, to increase competition in the Queensland spot market, "the government should split its generation businesses back into at least three".[37]

Subsequent to the publishing of the Grattan report, the Queensland government announced on 30 August 2018 the establishment of a third government owned energy company, CleanCo. CleanCo is intended to have a strategic portfolio of low and zero emissions generation assets. It will be set up with an initial $250 million of funding from the government to progress the development of public renewable energy generation assets. This is part of the governments plan to transition to 50 per cent renewable energy by 2030, and is also part of the government's "firm commitment to the continued public ownership of energy assets in Queensland". CleanCo will start with 1000 MW of new renewable projects like solar, wind and hydro and is expected to be trading in the NEM by mid-2019. [38]

The Queensland government expects the company to have a positive impact on the NEM, driving more competition in the energy sector and reducing prices.

37 Grattan Institute, *Mostly working - Australia's wholesale electricity market*, July 2018, p.47.

38 http://statements.qld.gov.au/Statement/2018/8/30/cleanco-to-make-power-bills-cheaper

ACCC view on market concentration and market manipulation

The ACCC's report cited issues of increasing market concentration in the NEM, as a result of acquisitions and closures of significant assets, as one of the causes of increases in retail electricity prices:[39]

> ...competition in bidding among rival generators is critical for driving efficient prices. Where markets are concentrated this can significantly affect bidding behaviour dramatically and lead to prices above efficient levels.

The ACCC concluded that the tightening of supply and demand has seen a general lift in wholesale prices across the NEM in recent years. The ACCC found that elevated prices had been driven by high and entrenched levels of concentration in the market, combined with fuel cost factors, "rather than identifiable uses or abuses of market power (for example, conduct of particular generators to 'spike' the price)".

While high prices would normally be a spur to new investment, according to the ACCC, other factors have come into play to limit new investment. These factors include policy uncertainty in relation to less carbon intensive forms of generation.

Previous AER analysis also downplayed rebidding as a factor affecting pricing

The AER's December 2017 analysis of the competitiveness of the NSW electricity market[40] found there was no evidence to suggest prices in NSW were driven by behaviour that would traditionally be associated with the exercise of market power in electricity markets "such as rebidding significant capacity at prices near the price cap close to dispatch". Instead the AER found market structure, the role of interconnection with adjoining regions and the constraints on coal generators provided by gas and hydro plant were all found to be issues that have the potential to affect the efficient and competitive operation of the NSW electricity wholesale market.

ACCC recommendations to solve market concentration

The report made a number of recommendations to address issues of market concentration in the NEM:

Recommendation 1: *Amendment of the NEL to prevent any acquisition or other arrangement (other than investment in new capacity) that would result in a market participant owning, or controlling dispatch of, more than 20 per cent of generation capacity in any NEM region or across the NEM as a whole.*

Recommendation 2: *The Queensland Government should divide its generation assets into three generation portfolios to reduce market concentration in Queensland. Once created, the Queensland Government should ensure that the three portfolios are separately owned and operated to maximise competition in the wholesale electricity market.*

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39 ACCC, *Restoring electricity affordability and Australia's competitive advantage*, https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_Exec%20summary.pdf, 11 July 2018, p.vi.

40 AER wholesale performance monitoring, NSW electricity market advice, Dec 2017

Recommendation 3: *Amend the NEL to provide the AER with powers to address behaviour which has the effect of manipulating the proper functioning of the wholesale market, together with the necessary investigation powers and appropriate remedies.*

Recommendation 4: *The Australian Government should operate a program under which it will enter into low fixed-price (for example, $45–50 per MWh) energy offtake agreements for the later years (say 6–15) of appropriate new generation projects which meet certain criteria.*

Recommendation 21: *A mechanism should be developed for third parties to offer demand response directly into the wholesale market. Design of the mechanism should commence immediately, building on work undertaken in the AEMC's Reliability Frameworks Review*

These recommendations will all help to alleviate market concentration. Measures that address issues of industry structure and barriers to entry will more directly address the causes of high and volatile prices than changes to the market rules which may compromise efficiency.

6 CONCLUSIONS

To the limited extent that bidding and rebidding behaviour in the market are seen to be a problem, the analysis shows that they are driven by high levels of market concentration. These issues related to industry structure should be addressed by policies that lower barriers to entry and promote efficient new investment.

This finding is consistent with the conclusions of the ACCC report, published in July 2018, "Restoring electricity affordability and Australia's competitive advantage". The ACCC highlighted that competition in bidding among rival generators is critical for driving efficient prices. It made a number of recommendations targeting reductions in market concentration and barriers to entry, and the promotion of new investment. These recommendations are currently under consideration by governments.

Recent trends in generation investment, as well as the announcement by the Queensland government on 30 August 2018 in relation to the establishment of CleanCo, a third government owned generator that will focus on the development of renewable energy generation, may also help to alleviate the impacts of market concentration.

Rebidding facilitates efficient wholesale prices and investment outcomes in the wholesale market. The rebidding process allows market participants to respond to changing market conditions and is integral to the daily operation of the power system and signals the need for new generation. Rebidding is likely to become more important in the future in reducing wholesale price volatility as more flexible and fast response generation and demand technologies enter the market. This is highlighted by the important role rebidding has played in the operation of the Hornsdale battery in lowering the Frequency control ancillary service prices.

Changes to the rules concerning bidding in the NEM are unlikely to resolve issues in the wholesale market that are driven by industry structure. It is more effective to deal with these issues directly, thereby avoiding the drawbacks to efficiency of changing the market rules themselves.

The Commission and AER analysed claims by Grattan that the cost of gaming in 2017 was $825 million and has increased since 2015. The analysis shows:

- The definition of gaming used by Grattan is too broad, inadvertently labelling both instances of volatility and rebidding as gaming.
- The impact of rebidding in the market, based on access to more granular AER data, is a cost in 2017 of $243 million (versus $825 million), with $214 million occurring in Queensland. This impact has fallen, not increased, since 2015.
- The cost of price spike events, in which rebidding was the cause, represents only one per cent of the wholesale cost of energy in the NEM in 2017. This cost, however small, is unlikely to have been passed through to consumers in 2017 as retailers typically enter into hedge contracts to prevent volatility and short term wholesale price changes being passed onto consumers.

- Rebidding can decrease wholesale prices as well as increasing them. The Grattan analysis ignores the positive effect of rebidding on ensuring efficient pricing, including price decreases, and in the longer term on investment.

Changes to the market design suggested by Grattan are not warranted and may be harmful:

- The analysis does not support making changes to the market design. Gate closure, including asymmetric gate closure, is not an appropriate solution to address rebidding. It does not offer any benefit that does not already exist via the contracts market, and it would risk efficiency if participants were hindered in their response to changing market circumstances. Any market gaming would move from close to dispatch to close to the gate closure, rather than being eliminated. The mechanism may distort the market because different generators have different capabilities to turn on or off and ramp up or down (coal generators may take many hours, while batteries can respond almost instantly). It might also provide a competitive advantage to non-scheduled generators and most loads as there are no time restrictions on their market participation decisions.
- As part of its proposition for a gate closure mechanism, Grattan commented that it did not consider the *Bidding in good faith* rule had been effective, and that the *Five minute settlement rule* would also not solve gaming issues. The Commission disagrees with these comments. The AER data indicates that late rebidding as a proportion of total rebids has declined since the *Bidding in good faith* rule was implemented. The Commission considers more efficient pricing and investment signals will result from implementation of the *Five minute settlement* rule.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	Australian Energy Market Commission
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National electricity objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
STPASA	Short term projected assessment of system adequacy

A PRIMARY CAUSE OF PRICE SPIKES - AER METHODOLOGY

The AER analysis of the Grattan price spike events uses the AER events register which records significant wholesale price variations in the NEM. A significant price event is defined either as a spot price greater than $250/MWh and three times the seven day volume weighted average or a spot price below -$100/MWh.

The AER's wholesale markets group then analyse trading intervals which have exceeded the events register price threshold and where the actual price is significantly different to the price forecast in pre-dispatch.

The AER uses publicly available data published by AEMO to analyse the causes of these events. The analysis, including a count of the variations and the broad reasons the variations have occurred, is published in Table 2 of the AER's weekly Electricity reports. These reports endeavour to explain why an actual price for a trading interval is signficantly different to forecast price. The reasons that typically lead to a price variation usually relate to changes in demand, supply, rebidding or network limitations.

The AER summarises the analysis of each trading interval and assign it into the following broad categories:-

Table A.1: **Primary cause categories**

	CATEGORY	DESCRIPTION
1	Constraint accuracy	An unforecast constraint bound which impacted the network in a material way, e.g. interconnector limits were significantly reduced
2	Generator Rebidding	Changes to generator offers affecting the merit order of the supply curve
3	Ramp rate	A ramp rate limitation of a generating unit prevented merit order generation setting price
4	Unplanned Network	Network constraints that have been invoked as a result of an unplanned network outage
5	Control system	Issues with control systems such as SCADA or governor control which impact market outcomes
6	Generator availability	A material change in the total capacity offered by a generator, often associated with a generator tripping
7	Rating change	A rating change on a line or a generator affecting the flow of electricity and in turn, expected market outcomes
8	Wind	Actual Wind farm generation materially different to forecast
9	Demand accuracy	Actual demand materially different to forecast

	CATEGORY	DESCRIPTION
10	Reclassification	Change to network availability or limits as a result of a reclassification, for example in response to a weather event
11	FCAS/Energy co-op	The price for energy was co-optimised with the ancillary service markets
12	Planned Network	Network constraints that have been invoked as a result of a planned network outage
13	Trap/Stranded	Generator not able to set price as a result of being outside its operating limits in FCAS
14	As forecast	Although an actual price occurred which exceeded the events register threshold, it was close to forecast.

Source: AER

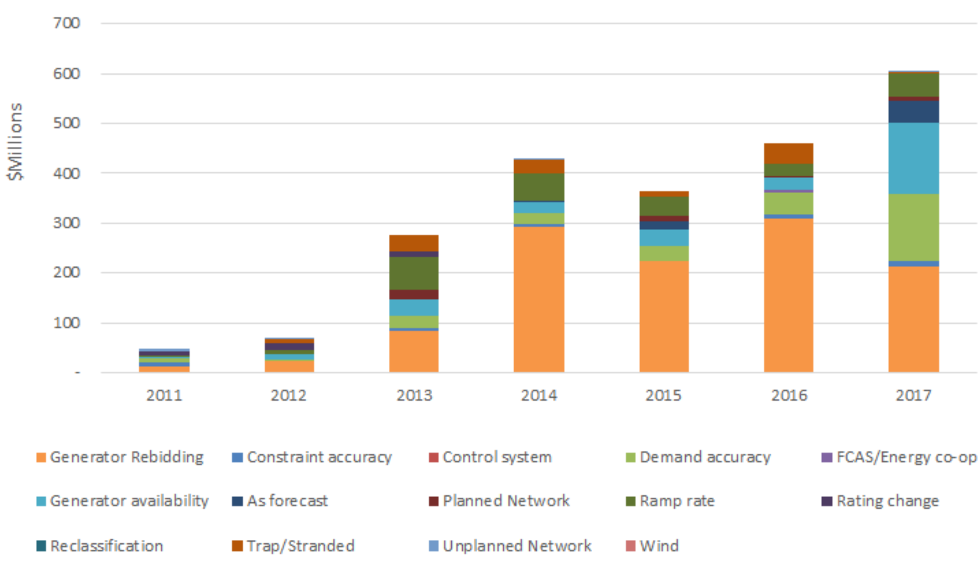
These categories are likely to grow over time as changes and additions to both load and generation play a greater role in the wholesale market. For example, demand side participation, solar aggregation and Virtual Power Plants (VPP's) amongst other developments.

B PRICE SPIKE COSTS BY STATE

Rebidding costs as a portion of price spike events, captured by the AER data, vary by state but reflect the same conclusion as for Queensland, where a number of causes other than rebidding contribute to the events. In 2017:

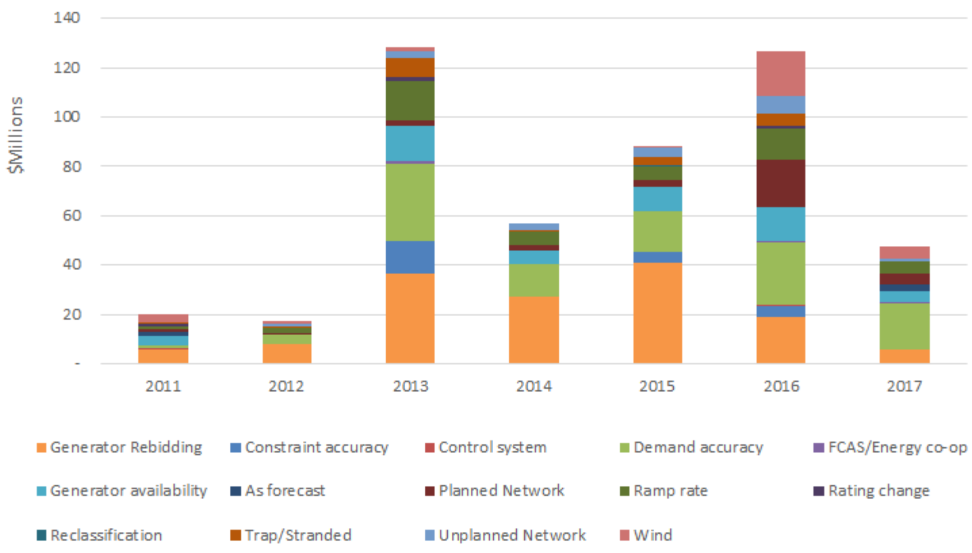
- in Queensland, rebidding is 36% of the price spike cost. Rebidding costs have declined by 5% since 2015. Price spike increases between 2015 and 2017 are driven by Demand accuracy and generator availability.
- in South Australia, rebidding is 13% of the price spike cost. Rebidding costs have declined by 85% since 2015. Price spike costs have fallen as a whole between 2015 and 2017.
- in New South Wales, rebidding is 23% of the price spike cost. Rebidding costs have declined by 63% since 2015. Price spike increases between 2015 and 2017 are driven by Generator availability and Demand accuracy.
- in Victoria, rebidding is 22% of the price spike cost. Rebidding costs have declined by 61% since 2015. Price spikes have fallen as a whole between 2015 and 2017
- in Tasmania, rebidding is 65% of the price spike cost. Rebidding costs have increased by 165% since 2015. Price spike increases between 2015 and 2017 are driven by Rebidding and Constraint accuracy.

Figure B.1: Grattan rebid cost by primary cause (Queensland)



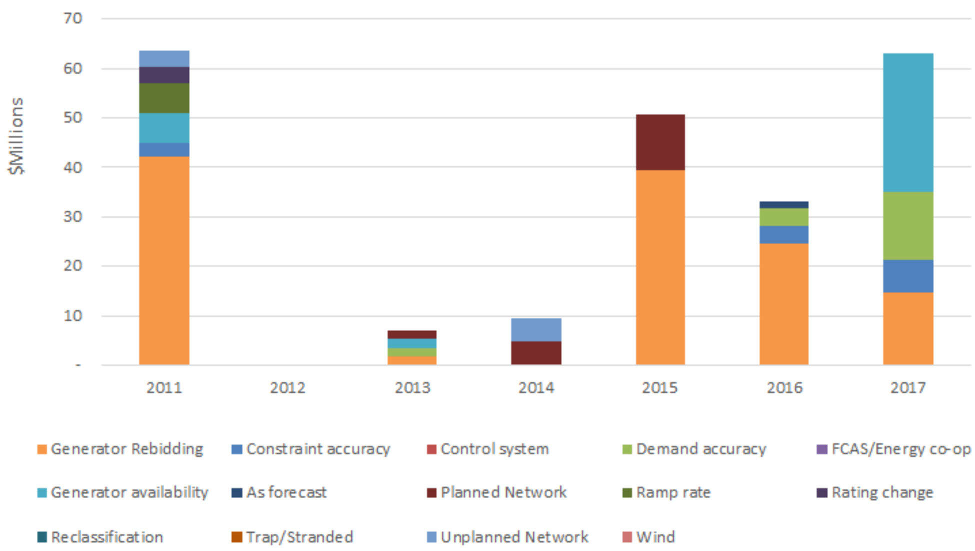
Source: AER

Figure B.2: Grattan rebid cost by primary cause (South Australia)



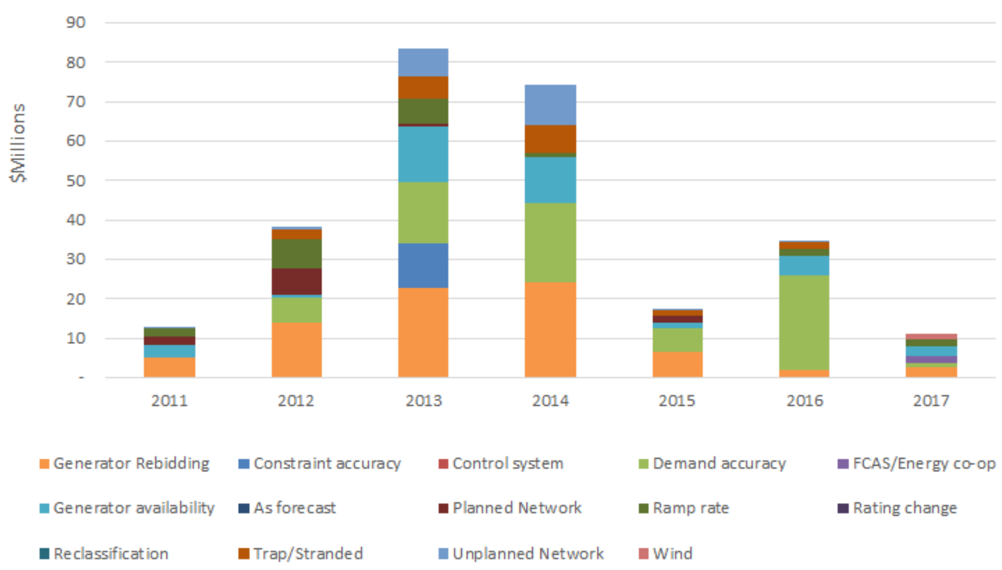
Source: AER

Figure B.3: Grattan rebid cost by primary cause (New South Wales)



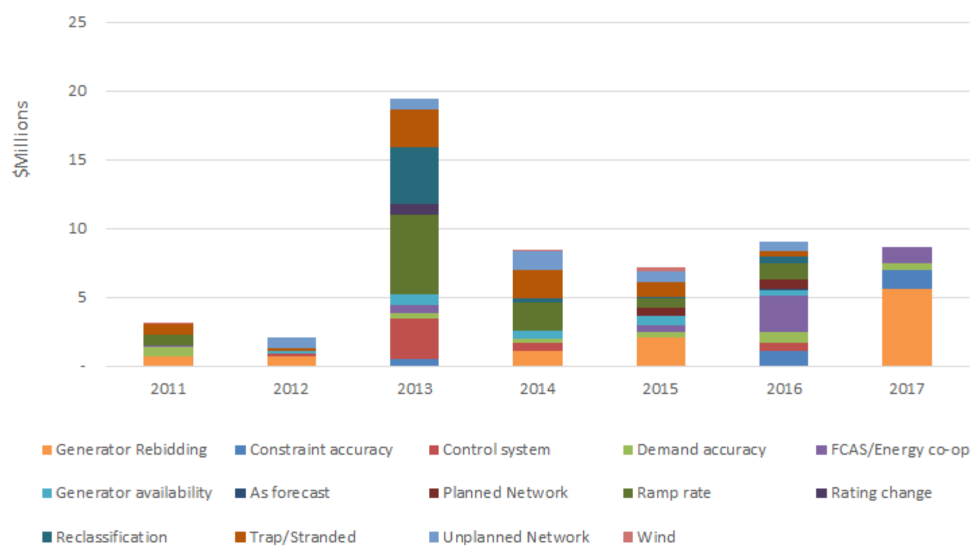
Source: AER

Figure B.4: Grattan rebid cost by primary cause (Victoria)



Source: AER

Figure B.5: Grattan rebid cost by primary cause (Tasmania)



Source: AER