AUSTRALIAN ENERGY REGULATOR

# Wholesale electricity market performance report

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# Preface

I am pleased to present our inaugural report on wholesale electricity market performance.

Ensuring Australian consumers, industry and government have access to relevant information on the performance of the markets is now more important than ever—as we see an unprecedented level of public interest in energy prices and transformation of the sector.

Electricity is a key input to production and is an essential service. Therefore the performance of the market can have implications for Australia's economy and international competitiveness, as well as affect the living standards of all Australians. So as the electricity sector undergoes a high level of change, it is critical we are able to explain the outcomes we are seeing in the wholesale markets. Consumers have every right to expect that market outcomes are explained and justifiable. It is also crucial governments have timely access to information to guide future policy.

This is the first report under the Australian Energy Regulator's (AER) powers to undertake a comprehensive and longer term assessment of the performance of wholesale electricity markets. In assessing competition and efficiency we have considered a wide range of information and metrics, and examined issues related to the market structure, conduct of market participants and the performance of the market. We interviewed a range of market participants and consumer representatives to inform our review. We also considered the impact of the policy environment, the transition to a lower emissions generation mix, technological developments and increasing fuel costs on the national electricity market.

This report presents a comprehensive evaluation of the performance of the wholesale electricity market and identifies areas we will monitor in the future. I am confident that this report is a great addition to the existing high quality publications from the AER and will be read with keen interest.

**Paula Conboy—Chair**

**December 2018**

# Summary

## Our monitoring

We monitor and report on the performance of the national electricity market (NEM) under the National Electricity Law. We are required to regularly monitor and review the performance of the wholesale electricity market, including analysing and identifying whether there is effective competition in the market and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market.

Effective competition requires a number of active competitors in the market. Prices must also reflect demand conditions and underlying costs (at least in the longer term), rather than the exercise of market power. And barriers to entry must be sufficiently low, such that high prices do not persist but rather lead to new entry.

We must report on the market at least every two years. We may also advise the Council of Australian Governments Energy Council (COAG EC) on market performance and identify whether legislative or regulatory reform is required.

This 2018 report is the first report covering all NEM regions. This report allows us to present a comprehensive picture of competition in the NEM. The purpose of this report is to set out our findings on the performance of the NEM. We have previously published reports on aspects of the New South Wales (NSW), Victorian and South Australian markets.[1] This report builds on that earlier analysis.

In assessing competition and efficiency we have had regard to a wide range of information and metrics. We examined issues related to the market structure, conduct of market participants, and the performance of the market. We intend to publish updates on some of these metrics and analysis through 2019 and 2020.

## The market is transforming

The market is undergoing a significant transformation. The NEM is transitioning to a lower emissions generation mix. Significant coal capacity has retired from the market and further plant closures are expected in the future. Meanwhile the share of generation from intermittent renewable sources has increased rapidly in recent years and more is on the horizon. Over time, this transformation will change market dynamics, with fast response 'flexible' generators, demand management and storage likely to have an increasing role.

The transformation is occurring in the context of significant community and government concern about electricity affordability and security, and reliability of supply. In recent years, average wholesale electricity prices in the NEM have risen significantly. This change reflects a general uplift in prices driving average prices higher, particularly after the summer of 2016–17. This result contrasts with previous periods of high prices, which were driven largely by extreme price spikes. Average prices eased in 2017–18, in all regions other than Victoria, but are still higher than historical levels.

A key driver of the more recent uplift in prices has been the exit of low cost coal generation, such as the Hazelwood power station in 2017. With less low cost energy available, higher cost generators are setting the price more frequently. In Victoria and South Australia, in particular, brown coal generation is setting the price significantly less since the Hazelwood power station closed. Hydroelectric power stations are setting price more often. Gas costs have also increased, which is contributing to electricity price increases.

Assessing whether there is effective competition and the market is operating efficiently can be challenging amidst market change so a longer term view of market performance is needed. It is now more important than ever to support an effectively competitive market so that the transformation can deliver outcomes that are in the long term interests of consumers.

## Other factors may be influencing prices

There are elements of the market which make it vulnerable to the exercise of market power. A few large vertically integrated participants control significant generation capacity and output in each region of the NEM. The output of a few large participants is necessary to meet demand in most regions a significant proportion of the time. This concentration provides a number of participants with greater potential to exercise market power. While participants may have an ability to exercise market power, they may not have an incentive to do so. A range of factors affect a participant's incentives to exercise market power, including its exposure to spot prices and government intervention.

Our review did not identify short term behaviour as a significant factor contributing to recent energy price rises. Our analysis, however, did identify longer term trends that will require ongoing monitoring. In particular, average offers from some black coal generators in NSW and Queensland have increased due to the increase in coal costs. But the increase in coal costs alone does not appear to explain all

1 AER, *Wholesale electricity performance monitoring—NSW electricity market advice*, December 2017; AER, *Wholesale electricity performance monitoring—Hazelwood electricity market advice*, March 2018.

of the increase in offers. Specifically, in Queensland average offers have increased significantly despite some evidence of a slight reduction in average coal costs. In addition, we identified issues related to participant conduct in South Australian frequency control ancillary services markets, but it seems unlikely these issues will be sustained as new participants have entered the market and the requirement for additional local services has been removed.

## Prospects for new investment

Supply and demand conditions have tightened over recent years, with significant low fuel cost capacity exiting in response to historical oversupply. Despite these tightened supply and demand conditions, there is still sufficient capacity in the NEM to meet expected demand and the Australian Energy Market Commission (AEMC) does not expect the reliability standard to be breached in the medium term. But the Australian Energy Market Operator (AEMO) has suggested additional generation capacity may be needed in the longer term.

In recent years almost all investment in new capacity has been in renewables, namely wind and solar. Currently there is significant committed future investment in wind and solar generation, supported by the renewable energy target, and other emissions reduction initiatives.

The retirement of aged coal fired generators, combined with the surge in intermittent renewable generation investment, has created challenges in managing the security of the power system. In addition to providing energy, coal fired generators played a useful role in supplying ancillary services that help maintain system frequency within standards, and other characteristics necessary for maintaining power system security. The AEMC has a number of reform processes underway to address system security concerns related to the changing generation mix. AEMO also has a number of tools available to it including the reliability and emergency reserve trader (RERT) mechanism and directions powers.

While the NEM has continued to meet the reliability standard in recent years, prices have risen to such a level that a signal for new entry for some lower cost technologies is emerging. Consistent with these findings, significant investment in new renewable generation is on the horizon. While the renewable energy target is contributing to rising investment, it is likely having less of an impact than in the past as the value of large-scale generation certificates is now declining.

If the rise of intermittent generation and the exit of large thermal capacity continues, there will be an increased need for flexible generation or storage that is able to match the variation in intermittent supply. Our analysis suggests price signals for new flexible, firming generation (such as open cycle gas turbines) are improving, but are not as strong as for other technologies. Flexible generators typically have higher operating costs so operate less frequently than other technologies and recover their costs during periods of very high prices. We are not currently seeing the price spikes that support these types of generators to recover their costs.

## Potential barriers to entry and impediments to efficient price signalling

A concentrated market structure increases the risk of outcomes that are not effectively competitive. The potential for new entry is an important feature of an effectively competitive market, particularly where ownership among existing participants is concentrated. New entry constrains a participant's ability to exercise sustained market power.

During our review, market participants identified a range of potential barriers to entry for new generation. A constant theme was that there is not the policy stability and predictability necessary to support ongoing generation investment in the NEM. Investment in long-lived generation assets requires long-term consistent policy signals to support investor confidence. Emissions policy instability in particular was identified as a key impediment to investment in the NEM. Interventions to address other energy policy objectives, such as reliability and affordability were also cited as factors stifling investment by creating uncertainty. For example, some participants noted while the South Australian Government directions following the black system event may have had short term benefits, they indicated that it had longer term implications on investor confidence.

In addition, some privately owned market participants raised concerns that government ownership in the sector is problematic. The operation and investment decisions of government owned businesses are perceived not to be market driven and influenced by non-commercial factors. While this may not be the case, the *perception* held by privately owned participants could have a dampening effect on investment.

There is however considerable investment in new wind and solar generation on the horizon, so it may be that these potential barriers to entry are not having as significant an impact on the sector as suggested during our enquiries. Nevertheless, we do consider the lack of consistent policy signals to support investor confidence is one of the biggest threats to competition and efficiency in the NEM over the long term. While achieving this policy environment will be a significant challenge, it is very important if we are to continue to rely on market signals to deliver an effectively competitive wholesale electricity market.

There may also be significant barriers to non-vertically integrated or new entrant generation participants obtaining finance and managing market exposure. To demonstrate revenue certainty and secure financial backing these participants need to obtain long-term contracts from a high credit rated retailer (which are typically the large vertically integrated participants). The Australian Competition and Consumer Commission (ACCC) similarly identified some developers are constrained in their ability to support new projects because some customers are unable to commit to long-term contracts. The ACCC has recommended the Australian Government enter into low fixed-price energy offtake agreements for the later years of appropriate new generation projects to deal with this issue.

In addition, a more general lack of liquidity in contract markets, particularly in South Australia may also make it more difficult for new entrant or non-vertically integrated generators and retailers to hedge against volatile spot prices.

Many participants also cited increased use of the RERT as distorting price signals. While the RERT is an important safety net that can underpin reliable electricity supply, it can have a number of distortionary effects on the market. We are particularly concerned that the RERT may potentially crowd out efficient market led demand response.

## Where to from here?

A number of processes are currently underway that will address many of the issues we have identified. The ACCC made recommendations targeted at concerns around market concentration, investment, contract market liquidity and reporting additional contract information to the Australian Energy Regulator. The AEMC also has a significant work program considering issues related to demand response, the RERT framework, frequency control and managing system security. The COAG EC is also developing a strategic energy plan in consultation with the Energy Security Board to provide direction to market bodies and participants in the transitioning energy system.

We will continue monitoring the issues we have identified, including investment trends and incentives in the NEM, the implications for competition of increased penetration of intermittent renewable generation, liquidity in contract markets and participant offer behaviour.

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# 1. Monitoring the national wholesale electricity market

### Key points

- The Australian Energy Regulator (AER) reports on whether there is effective competition in the national wholesale electricity market and identifies impediments to competition and efficiency.
- This is our first report covering all regions in the national electricity market (NEM). We have previously published reports on aspects of the New South Wales (NSW), Victorian and South Australian markets.
- Our reports provide information and analysis that assist stakeholders to understand the market drivers, inform future investment decisions and guide policy reforms.
- Our reports focus on competition and efficiency of the NEM.
- Our monitoring approach includes analysing the structure of the market, the behaviour of participants in the market and the overall performance of the market.
- We based our conclusions on a broad range of information and analysis.

The AER monitors the performance of the NEM. The NEM is a wholesale spot market into which generators in eastern and southern Australia trade electricity (box 2.1). This chapter outlines why and how we monitor this market:

- Section 1.1 describes the basis for our monitoring role and this report.
- Section 1.2 explains the concepts of competition and efficiency.
- Section 1.3 outlines how we prepared the report and its structure.

## 1.1 Our reports provide information on the performance of the NEM

### 1.1.1 We monitor the market under the National Electricity Law

We monitor and report on the performance of the NEM under the National Electricity Law (NEL). We are required to regularly monitor and review the performance of the wholesale electricity market, including analysing and identifying whether there is effective competition in the market and whether there are market features that may be detrimental to effective competition or efficient functioning of the market.

We must report on the market at least every two years. We may also advise the Council of Australian Governments Energy Council on market performance and identify whether legislative or regulatory reform is required.

This 2018 report is the first report covering all NEM regions which allows us to present a comprehensive picture of competition in the NEM. This report sets out our findings on the performance of the NEM. We have previously published reports on aspects of the NSW, Victorian and South Australian markets.[2] This report expands and builds on that earlier analysis.

We intend to publish more regular updates through 2019 and 2020.

### 1.1.2 Our reporting supports efficient and competitive markets

Our reports provide an independent, expert and long term perspective on the performance of the wholesale electricity markets.

We also have other performance reporting obligations across our wholesale, retail and network areas. In wholesale, our other functions generally focus on short term market outcomes, compliance issues and individual price events.

Our monitoring roles support the national electricity objective in the NEL, which is to promote the efficient investment, operation and use of electricity services for the long term interest of consumers. Our monitoring and reporting assists consumers to understand the key drivers of outcomes in the wholesale electricity market and make more informed consumption decisions. Providing timely and relevant information to the market also supports efficient investment decisions and provides insights to policy makers to guide regulatory change.

2 AER, *Wholesale electricity performance monitoring—NSW electricity market advice*, December 2017; AER, *Wholesale electricity performance monitoring—Hazelwood electricity market advice*, March 2018.

### 1.1.3 This report focuses on the NEM

Several products are traded in the NEM. For our 2018 report we focused primarily on the regional spot energy markets. We also analysed the frequency control ancillary services markets and considered the implications of the contract markets and incentives offered under the renewable energy target scheme where relevant.

## 1.2 We analyse competition and efficiency in the wholesale electricity markets

Our assessment of market performance includes analysing whether there is effective competition and if the market is functioning efficiently.

### 1.2.1 Effective competition in the NEM

The level of competition in any market can be assessed against a range of competitive outcomes. At one end is a monopoly where one firm effectively controls all output in the market and there is no competition. At the other end is a perfectly competitive market where no firm holds market power at any time. Perfect competition rarely arises in practice.

The NEL requires us to assess whether there is 'effective' competition, rather than perfect competition, and provides a non-exhaustive list of factors we must have regard to:[3]

- whether there are active competitors in the market and whether those competitors hold a reasonably sustainable position in the market (or whether there is merely the threat of competition in the market)
- whether prices are determined on a long term basis by underlying costs rather than the existence of market power, even though a particular competitor may hold a substantial degree of market power from time to time
- whether barriers to entry into the market are sufficiently low so that a substantial degree of market power may only be held by a particular competitor on a temporary basis
- whether there is independent rivalry in all dimensions of the price, product or service offered in the market, and
- any other matters the AER considers relevant.

The NEL suggests the wholesale electricity market may still be considered 'effectively' competitive over the long term even if participants hold a substantial degree of market power at times. In particular, the NEL refers to prices over the long term and market power held by a participant on a temporary basis. These factors suggest we should have regard to whether market power is *sustained*.

An energy only market, such as the NEM, is characterised as being effectively competitive if it has many participants, with no one participant controlling a high proportion of capacity for a significant period of time. Participants have an incentive to bid close to their fuel and operating costs; otherwise, they risk a cheaper competitor displacing their output. Relatively short periods of high volatile prices driven by tightened supply and demand conditions enable generators to recover their fixed costs and earn a return on their investments.

Investment and exit decisions in an effectively competitive energy only market are market led. Periods of high spot and contract prices driven by tightened supply and demand conditions provide a signal for new generators to enter the market. If demand decreases relative to supply, there is downward pressure on prices, which should prompt higher cost generators to exit the market. In an effectively competitive energy only market, barriers to entry and exit are sufficiently low so investors can respond efficiently to price signals.

### 1.2.2 Efficiency in the NEM

The NEL does not provide a definition of efficiency, but it is a well understood concept in economic literature. Economic efficiency is concerned with maximising overall welfare in a market given the available resources. We have had regard to three dimensions of efficiency:

- Allocative efficiency—resources are allocated to their highest value uses. In electricity markets, this means the electricity that consumers demand is provided by the lowest cost supply and demand side options.
- Productive efficiency—the value of resources used are minimised for a given level of outputs. This includes removing any inefficient costs in supplying electricity to consumers.
- Dynamic efficiency—resources are allocated efficiently over time. In energy markets this means having the right mix of demand and supply side options to provide maximum output at minimum cost over time.

## 1.3 We consulted on our approach and relied on a range of information and analysis

### 1.3.1 Our approach included analysing the structure, conduct and performance of the markets

In 2017 and 2018 we consulted on our approach to this report. We have applied a structure–conduct–performance framework to analyse the market and our assessment has focused on effective competition and efficiency. In broad terms:

3 Section 18B National Electricity Law.

- structure refers to the market structure and includes the number and size of buyers and sellers, the nature of the products and the height of barriers to entry
- conduct refers to firms' behaviour in the market, including production, and buying and selling decisions
- performance refers to market outcomes, usually by reference to concepts of efficiency.

Our *Wholesale electricity performance monitoring—Statement of approach* and the *Wholesale electricity performance monitoring—2018 focus* provide detail on this framework and the areas we identified for focus in 2018. We also published the *Wholesale electricity market performance report 2018—Methods and assumptions* and the *Wholesale electricity market performance report 2018—LCOE modelling approach, limitations and results,* which sets out more detail on the calculations and methods we apply.

### 1.3.2 We analysed information from many sources

As required under the NEL, we used a range of publicly available information in the first instance,[4] including information and data published by the Australian Energy Market Operator (AEMO), the Australian Energy Market Commission (AEMC) and the Australian Securities Exchange.

We also considered reviews or inquiries by other agencies that provide useful information or analysis, notably:

- The Australian Competition and Consumer Commission's (ACCC) retail electricity supply and prices inquiry—On 11 July 2018 the ACCC released its final report to the Treasurer on the supply of retail electricity and the competitiveness of retail electricity prices.
- AEMC retail competition and residential price trends reviews—On 15 June 2018 the AEMC released its annual review of retail energy competition in the NEM and on 18 December 2017 it released its annual report on residential electricity price trends.
- The independent review into the future security of the NEM—On 9 June 2017, an expert panel chaired by the Chief Scientist, Dr Alan Finkel AO, released its Blueprint for the future for maintaining security and reliability in the NEM.

In addition, we interviewed a number of industry participants and consumer representatives to obtain insights on competition and efficiency issues.

### 1.3.3 How this document is structured

While we adopted the structure–conduct–performance framework to analyse the markets, this report is structured around our key findings and issues we identified.

This report covers:

- Chapter 2—overview of market conditions and change drivers
- Chapter 3—whether the current market structure supports efficient and competitive markets
- Chapter 4—whether participants are exercising market power
- Chapter 5—the prospects for new investment
- Chapter 6—barriers to entry and efficient price signalling
- Chapter 7—work on the horizon to address issues identified.

Appendix A—sets out more detail on aspects of our analysis of participant conduct.

4 Section 18D(1)(a), National Electricity Law. We must use publicly available information to carry out our wholesale monitoring functions in the first instance. If we identify an issue, then we may use our powers under section 28 of the National Electricity Law to acquire non-public information.

# 2. Market conditions and change drivers

### Key points

- The market is undergoing significant transformation. The generation mix is changing and new products and markets are emerging. Fast response 'flexible' generators, demand management and storage are likely to have an increasing role in the market in future.
- Annual prices in the national electricity market (NEM) have increased significantly over the past three years. Volatility has not significantly contributed to rising prices beyond the peak summer periods. Rather, a sustained increase in prices has driven the average price higher. A number of factors have contributed to rising prices including the exit of a number of coal-fired generators, increased gas and coal fuel costs, and coal supply issues. However these factors may not explain all of the increase.
- The reduced supply of services also increased costs of frequency management services in the market.

Electricity generated in eastern and southern Australia is traded through the NEM, a wholesale spot market in which changes in supply and demand determine prices in real time (box 2.1).

To assess whether the NEM is effectively competitive or efficient over the long term, it is critical to understand the market conditions and the factors driving outcomes. These factors can drive participant behaviour and explain price movements. Understanding these factors can also help determine whether current market conditions will persist.

This chapter explains the current market transformation and market conditions in recent years:

- Section 2.1 provides an overview of the current NEM transformation and its challenges.
- Section 2.2 summarises spot electricity price outcomes over the past five years.
- Section 2.3 outlines the changes in supply conditions that contributed to recent price increases.
- Section 2.4 provides information on increased costs associated with managing system frequency.

## 2.1 The market is transforming

The wholesale electricity market is undergoing significant transformation. This transformation is likely to continue with further penetration of both renewable generation and storage technologies. Fast response 'flexible' generators and storage are likely to have an increasing role as intermittent generation continues to connect to the grid.

### 2.1.1 The generation mix is changing

The NEM is transitioning to a lower emissions generation mix. Coal remains the dominant fuel source with Queensland, New South Wales (NSW) and Victoria having significant coal generation installed (figure 2.1). But in recent years significant coal fired capacity has retired from the market and further plant closures are likely in the near future (section 5.1.1). In 2017–18 coal accounted for around 41 per cent of capacity and supplied 73 per cent of output in the NEM.

While generation from renewable sources is a relatively small part of the overall generation mix, its share has been rising rapidly in recent years (figure 2.2). There is also significant investment in renewables on the horizon, with all committed investments in the NEM in renewable generation.

Generation from wind made up less than 1 per cent of total output in the NEM 10 years ago, rising to over 6 per cent by 2017–18. Wind penetration is especially strong in South Australia, meeting around 40 per cent of the state's electricity requirements in 2017–18. Significant investment in new wind generation capacity is also forecast for the NEM, with 13 wind projects (nearly 2500 megawatts (MW)) expected to be commissioned by the end of 2019–20 financial year.

Solar technologies are also an increasing part of the generation mix. Rooftop solar is not dispatched in the wholesale market, but it reduces the demand that must be met by the dispatchable generation. Uptake of rooftop solar photovoltaic (PV) systems has risen significantly since 2010. The output of rooftop solar PV systems was virtually zero until 2010, but by 2018 it was meeting 3.4 per cent of the NEM's electricity requirements. Rooftop solar penetration is highest in South Australia, where it supplies above 8 per cent of the state's electricity needs. Rooftop solar penetration is also rising in Queensland, supplying over 4 per cent of electricity requirements in 2017–18.

Large scale solar generation is also emerging in the NEM. While it accounted for less than 1 per cent of total output, its contribution to the overall generation mix will likely grow with funding support from the Australian Renewable Energy Agency and the Clean Energy Finance Corporation. At November 2018, the NEM had around 1850 MW of installed large scale solar projects. A further 22 projects (over

2000 MW) are expected to be commissioned across the NEM by the end of 2019–20 financial year (section 5.1).

Supply and demand patterns for electricity from the grid are also changing. The demand for grid supplied electricity can fall in the middle of the day when rooftop solar generation is at its highest. This demand is commonly hitting new record lows, and peak demand on the grid is shifting to later in the day as rooftop solar generation decreases.

There are a number of technical challenges associated with the transformation of the wholesale electricity market (section 5.1.3).

### Box 2.1 The NEM

The NEM is a wholesale spot market for trading electricity. The market covers five regions—Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania. The regions are connected via high voltage transmission links called interconnectors.

Generators participate in the NEM by submitting offers to the Australian Energy Market Operator (AEMO) to supply quantities of electricity at different prices for periods of time. Around 130 large power stations (comprising around 240 plant units in total) make offers to supply quantities of electricity in different price bands. The generators include coal fired plant, gas powered generators, wind turbines, hydroelectric plant and solar farms. Electricity generated by rooftop solar photovoltaic systems is not traded through the NEM.

AEMO ensures electricity generation is matched with demand in real time by issuing instructions to generators every 5 minutes (known as a dispatch interval). AEMO selects the generators with the lowest offers first, and then progressively more expensive offers until enough electricity can be dispatched to meet demand. The generator who provides the last megawatt needed to meet demand (or the marginal generator) sets the price for the 5 minute dispatch interval.

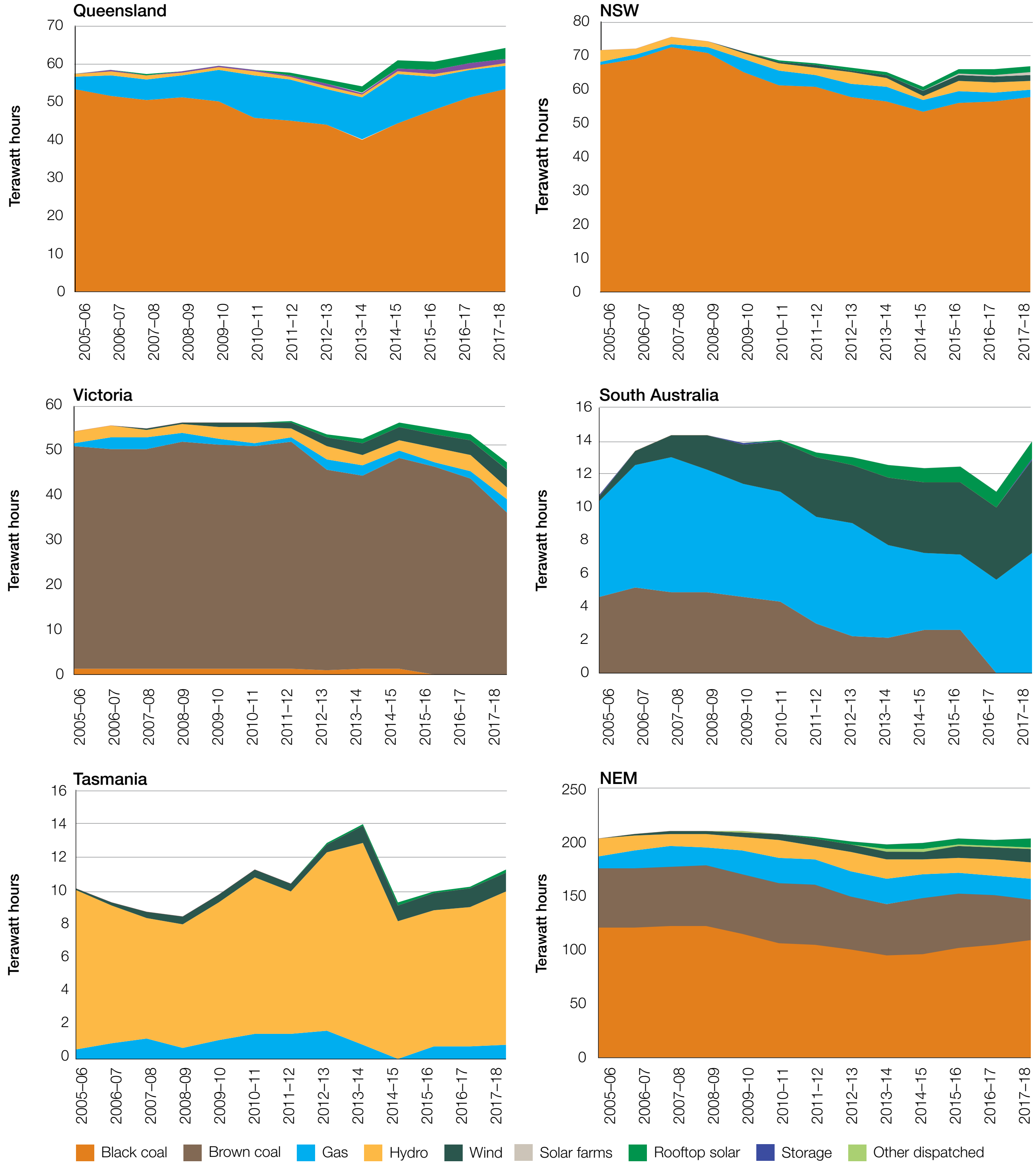
Spot prices can fluctuate in the NEM every 30 minutes. Participants can offer their capacity at any level between the price floor (–$1000 per megawatt hour (MWh)) and the price cap ($14 500 per MWh). The highest priced offer needed to meet demand sets the price every 5 minutes (dispatch price). Every 30 minutes, the six dispatch prices are averaged to determine the spot price and generators that were dispatched are paid this price for the electricity they produce regardless of how they bid.

In practice, generators use a number of strategies to manage the risk of fluctuating wholesale spot prices in energy only markets. Generators and retailers will often enter into hedge contracts traded on the Australian Securities Exchange or negotiated directly between the two parties (known as over-the-counter), which lock in future electricity prices.[5] Participants also often have both generation and energy retailing businesses to balance out the risks across each market.

While the market is designed to meet electricity demand in a cost-efficient way, other factors such as network limitations can intervene. For example, at times, the network around the lowest cost generator may be congested, so to manage system security AEMO deploys more expensive (out of merit order) generators located in an uncongested area of the network instead. At other times, market conditions may allow a generator to bid in ways that cause prices to rise above competitive levels, for example when a participant holds market power and rebids their capacity from low to high prices.

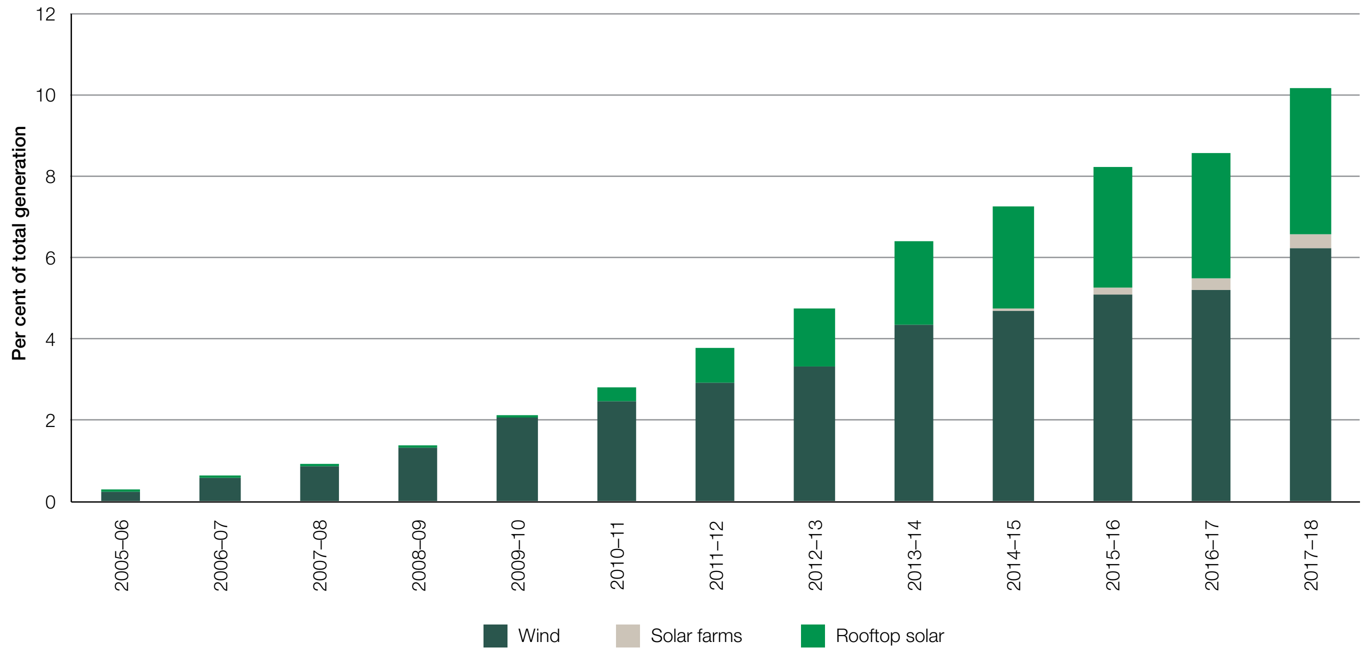
5 Generators may also use a range of other risk management strategies such as purchasing weather derivatives that reduce exposure in the event of adverse or unexpected weather conditions.

**Figure 2.1 Changes in electricity generation, by fuel source**




Source: AEMO data, AER analysis.

Figure 2.2 Wind and solar generation share of total output in the NEM




Source: AEMO data, AER analysis.

### 2.1.2 Over time the transformation will change market dynamics, with 'flexible' capacity likely to play an increasingly significant role

With the growth in renewables, generation that can effectively match the variation in intermittent supply is likely to play an increasingly significant role in the market. These 'flexible' technologies include storage technologies (such as batteries) and generation (such as fast start gas and hydroelectricity) that is flexible in its ability to start and stop quickly at low cost, or ramp up and down quickly. Flexible capacity (14 500 MW) currently makes up around 35 per cent of total capacity in the NEM.[6]

Energy storage is expected to play a significant role in Australia's energy supply mix, because it can match variable production with demand, and contribute to power system security. The Hornsdale Power Reserve, a 100 MW lithium-ion battery facility funded by the South Australian Government, began operating in December 2017. Large scale storage is also being considered through various additional pumped hydroelectric projects. These projects allow hydroelectric generation plant to overcome their energy limitation issue by reusing water. Water is pumped from a low reservoir to a high reservoir at times of low prices, so that it is available for generating in higher priced periods. Advances in technology and the rise of intermittent generation are providing new opportunities to deploy this form of energy storage at a larger scale. In particular, pumped hydroelectricity forms the basis of the 'Snowy 2.0' (2000 MW) and 'Battery of the Nation' (2500 MW) proposals in NSW and Tasmania.

Demand management technologies may also change how consumers interact with the market and support some aspects of power system security and reliability in future. The Australian Energy Market Commission has recommended a package of reforms to facilitate demand response (chapter 7).

Some market participants are responding to the increased penetration of intermittent renewable generation by launching financial 'firming products'. Providers of these products typically hold controllable generation to complement the intermittent generation profile. This may assist with managing the increased price and power system security risk posed by increased penetration of a more variable generation mix in future. While some generators have offered similar products for some time, new participants are entering the market, in particular to provide back up for wind and solar. In 2018 ERM Power launched a solar firming product and AGL Energy offered a wind firming product, for example. The market has potential to grow further with Snowy Hydro identifying its ability to offer firming products as one of the benefits of the proposed Snowy 2.0 project.

We expect monitoring developments in flexible capacity and firming products will be an area of growing focus for the AER in coming years as the transformation continues.

6 Because hydroelectric generation cannot generate at full capacity over the long term, using capacity may overstate the amount of flexible generation available.

## 2.2 Electricity prices have increased

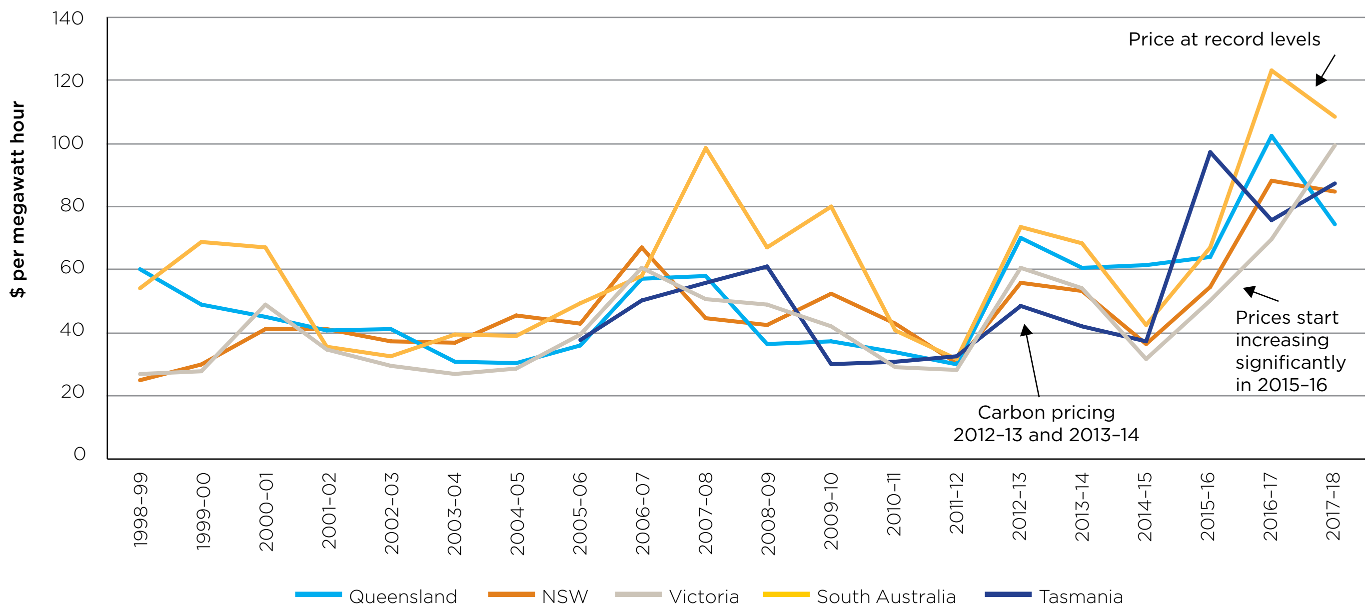
### 2.2.1 Annual average wholesale prices are at record levels

The transformation of the electricity markets has coincided with an increase in electricity prices. Average prices in 2016–17 and 2017–18 were the highest they have been since the NEM started 20 years ago. Wholesale price increases are a component of retail bills, so increases in wholesale prices ultimately affect the prices customers pay for electricity (box 2.2).

Annual volume weighted average wholesale electricity prices have been trending upwards for several years (figure 2.3). Prices rose in 2012–13 and 2013–14 with the introduction of the carbon pricing scheme, and fell again in 2014–15 with its repeal. Since then, annual average prices have more than doubled in most regions:

- In 2015–16, annual prices rose in every NEM region, increasing by around 50–60 per cent in Victoria, NSW and South Australia, and 160 per cent in Tasmania.
- In 2016–17, prices rose even more sharply, reaching record annual prices in all regions, except Tasmania. Wholesale prices increased by around 60–85 per cent in South Australia, NSW and Queensland, and 40 per cent in Victoria. In South Australia, average annual prices reached a record high of $123 per megawatt hour (MWh), which is the highest annual average price in any region since the market started.
- In 2017–18, prices eased in most states but remained close to record levels. The annual price in South Australia remained the highest in the NEM. Victoria held the second highest average price, after increasing for the third year in a row. The annual price in Queensland fell to the lowest in the NEM.

**Figure 2.3 Annual volume weighted average prices in the NEM**




Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AEMO data, AER analysis.

### Box 2.2 How the wholesale market affects retail bills

The performance of the wholesale market can have a significant impact on retail prices and electricity bills. But it can be difficult to measure the extent of that impact.

A typical retail electricity bill includes: wholesale costs of buying electricity in spot and hedge markets, network costs for transporting electricity, and retailer costs and margins. Wholesale costs average around 30–50 per cent of a residential electricity bill.

Electricity retailers purchase electricity in the wholesale spot market and sell it to consumers packaged with network services. Retailers and generators manage the risk of wholesale prices fluctuating by entering into financial hedge contracts (box 3.5).

It is difficult to separate the full impact of wholesale costs on electricity bills because there is little visibility around how, and to what extent, participants have hedged their wholesale exposure. Similarly, changes in wholesale prices are not immediately, or uniformly, reflected in retail prices. As wholesale prices change, the impact on retail prices will depend, for example, on how exposed individual retailers are to the spot price, how they structured their portfolios and when their contracts were entered into or expire.

### 2.2.2 High prices are occurring simultaneously across the NEM

Historically, the market has experienced a period of high average prices for one or two quarters, confined to only one or two regions. These events were usually driven by localised supply and demand events that would resolve relatively quickly. The comparatively high average price in Tasmania in quarter one 2016, for example, was driven by unprecedented and extended drought that contributed to low dam levels for hydroelectric generation, combined with a major fault on the Basslink interconnector that connects Tasmania to the mainland. Average prices in most other regions for this quarter were considerably lower with prices in NSW, Victoria and South Australia between $46–54 per MWh (figure 2.4).

In contrast, quarterly average price rises since 2017 largely occurred simultaneously across the NEM and were generally sustained above historical levels throughout 2017 and 2018. All regions experienced one or more quarters at close to or above $100 per MWh in 2017.

**Figure 2.4 Quarterly volume weighted average prices in the NEM, $ per MWh**

| | Queensland | NSW | Victoria | South Australia | Tasmania |
|---|---|---|---|---|---|
| 2013 Q3 | 60 | 56 | 55 | 70 | 47 |
| 2013 Q4 | 59 | 55 | 50 | 71 | 41 |
| 2014 Q1 | 71 | 51 | 64 | 78 | 41 |
| 2014 Q2 | 51 | 50 | 48 | 53 | 39 |
| Annual average 2013-14 | 60 | 53 | 54 | 68 | 42 |
| 2014 Q3 | 32 | 40 | 38 | 48 | 36 |
| 2014 Q4 | 68 | 33 | 28 | 32 | 40 |
| 2015 Q1 | 107 | 35 | 28 | 40 | 39 |
| 2015 Q2 | 32 | 37 | 32 | 48 | 34 |
| Annual average 2014-15 | 60 | 36 | 31 | 42 | 37 |
| 2015 Q3 | 45 | 46 | 39 | 69 | 38 |
| 2015 Q4 | 43 | 45 | 43 | 59 | 80 |
| 2016 Q1 | 89 | 46 | 50 | 54 | 174 |
| 2016 Q2 | 77 | 81 | 69 | 87 | 114 |
| Annual average 2015-16 | 63 | 55 | 50 | 67 | 101 |
| 2016 Q3 | 54 | 56 | 53 | 133 | 55 |
| 2016 Q4 | 66 | 66 | 35 | 75 | 38 |
| 2017 Q1 | 194 | 135 | 85 | 160 | 99 |
| 2017 Q2 | 87 | 94 | 107 | 118 | 114 |
| Annual average 2016-17 | 100 | 88 | 70 | 122 | 76 |
| 2017 Q3 | 82 | 95 | 103 | 102 | 97 |
| 2017 Q4 | 73 | 81 | 88 | 85 | 85 |
| 2018 Q1 | 72 | 74 | 120 | 144 | 91 |
| 2018 Q2 | 72 | 88 | 86 | 101 | 77 |
| Annual average 2017-18 | 75 | 84 | 99 | 108 | 87 |
| 2018 Q3 | 80 | 90 | 84 | 95 | 43 |

Note: Volume weighted average price is weighted against native demand in each region. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

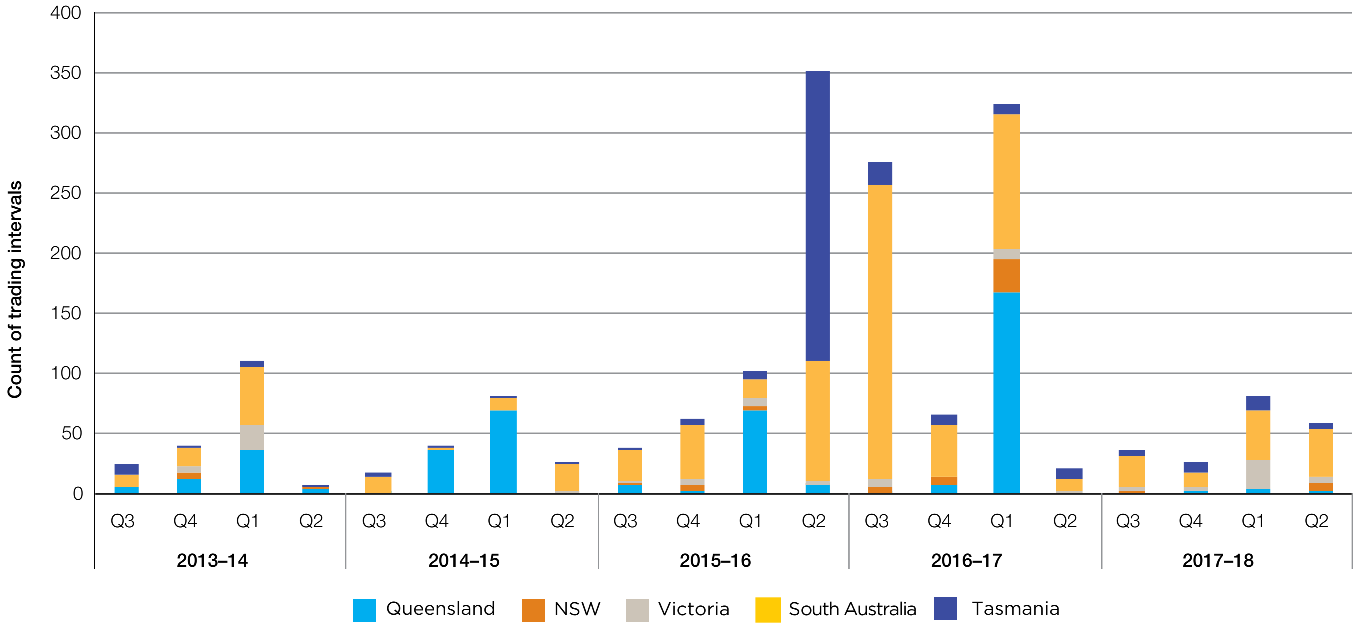
Source: AEMO data, AER analysis.

### 2.2.3 Volatility has not been a significant driver of more recent price increases

High average prices can be driven by a general uplift in prices or a more limited number of extreme price events. Historically in the NEM, a limited number of extreme price events were a major driver of high average prices. However, this situation changed after the summer of 2016–17 with high average prices occurring through the remainder of 2017 and into 2018 despite there being very few extreme price events. The spot price exceeded $300 per MWh on only 205 occasions in 2017–18, compared with 688 occasions in 2016–17 and 555 occasions in 2015–16 (figure 2.5).

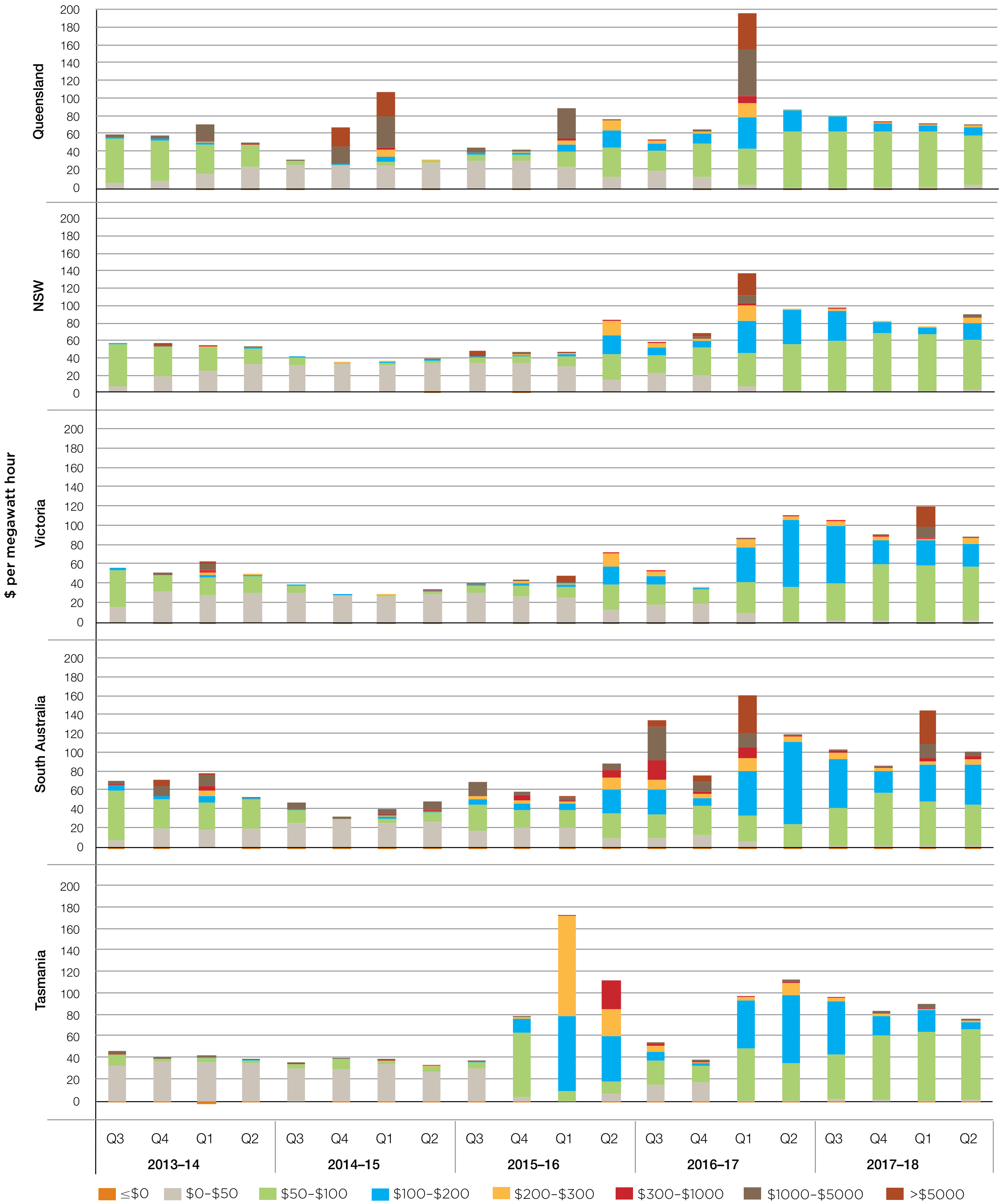
A general uplift in prices contributed more significantly to recent price rises. Figure 2.6 shows the extent to which different spot prices within defined bands contributed to average wholesale prices in each region. Until the summer of 2016–17, periods of high average prices were associated with spot prices above $5000 per MWh (shown in brown). After that summer, however, average prices were higher than historical levels despite very few of these extreme price events. A key driver of the sustained high average prices was the almost complete disappearance of spot prices below $50 per MWh (grey) and a growth in the instances of prices between $50–200 per MWh (green and blue).

**Figure 2.5 Market volatility—spot prices above $300 per MWh**




Source: AEMO data, AER analysis.

## Figure 2.6 Contribution of different price bands to quarterly wholesale prices




Note: Volume weighted average prices.

Source: AEMO data, AER analysis.

## 2.3 Changes in supply conditions have contributed to the general uplift in electricity prices

Movements in spot prices are not necessarily an indicator of the state of competition or efficiency in the market. Price movements may reflect changes in underlying costs or supply and demand conditions. Indeed, changes in supply conditions have driven higher average spot prices in recent years.

Over the past five years, the leading contributors to short-term price spikes have been rebidding, generator availability, inaccurate demand forecasting and generator ramp rates (section 4.2).

However, changes in supply conditions have contributed significantly to the sustained uplift in prices experienced in more recent years. A large amount of low fuel cost capacity has exited the market (section 5.1.1). The closure of the brown coal Hazelwood power station in particular had a significant impact. As expected, the exit of large, cheap coal fired generators means higher cost generators now set prices more frequently (box 2.1 discusses how prices are set in the NEM).

Figure 2.7 shows the percentage of time that each fuel type contributes to setting the price in each region. The percentage of time that the comparatively lower fuel cost brown coal generation set the price in Victoria fell significantly. As highlighted in our Hazelwood advice,[7] in the 12 months before Hazelwood power station closed in March 2017, brown coal generators set the price around 34 per cent of the time in Victoria. This share fell considerably after Hazelwood closed, with brown coal rarely setting the price in any region. Instead hydroelectric generators set the price more often. There was also a small increase in how often gas generators set the price.

### 2.3.1 The cost of gas and black coal has risen

The generators that remain in the market are also offering capacity at much higher prices than previously. In part, this is due to higher upstream fuel costs. Gas prices have increased significantly in recent years, increasing the cost of gas fired generation. Gas fired generators source their gas from a variety of sources. When deciding whether to use gas for electricity generation, market participants will often value their gas at the price they could sell it on the spot market, including the short term trading markets in Adelaide, Brisbane and Sydney, the declared wholesale gas market in Victoria or the Wallumbilla hub. Gas prices in these markets doubled between July 2013 and 2016, but have since eased slightly (figure 2.8). The increase in gas prices was largely due to the ramp-up of liquefied natural gas exports exposing domestic gas to international prices, and declining sources of domestic gas supply. Government moratoria and environmental controls are preventing new gas supply to the domestic market.[8]

We also observed higher offers from NSW and Queensland black coal generators. The export price of Newcastle coal increased 50 per cent between July 2013 and July 2018 (figure 2.9). As highlighted in our NSW advice,[9] higher coal prices contributed to higher offers from NSW coal generators exposed to this price.

But increases in fuel costs may not explain all of the increases in offer prices. We cannot rule out that a lack of competitive constraint contributed to higher offers—in particular for Queensland black coal generators which did not face higher fuel costs (section 4.1.2). In fact, the Australian Competition and Consumer Commission (ACCC) Retail Electricity Pricing Inquiry found that the weighted average fuel cost for Queensland black coal generators declined 5 per cent between 2015 and quarter one 2018.[10] Coal supply issues from late 2016 into 2017 drove higher offers from NSW coal generators, but there was also reduced competitive constraint on these generators when the Hazelwood power station closed in March 2017.

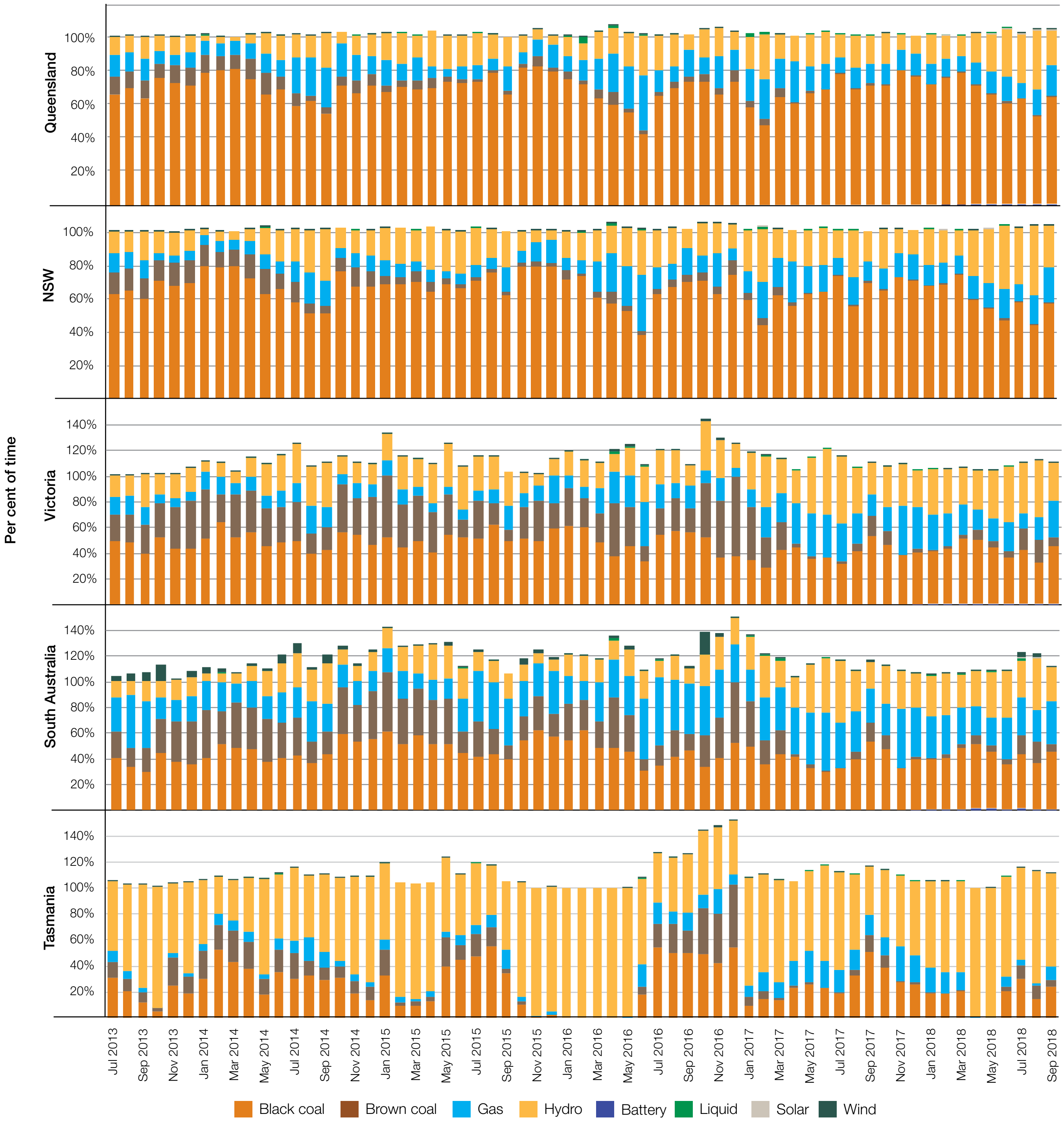
7 AER, *Electricity wholesale performance monitoring—Hazelwood advice*, March 2018.

8 ACCC, *Gas inquiry 2017–2020—Interim report*, July 2018, pp. 12–21.

9 AER, *Electricity wholesale performance monitoring—NSW electricity market advice*, December 2017.

10 ACCC, *Retail electricity pricing inquiry—final report*, July 2018, p. 67.

## Figure 2.7 Price setter by fuel type and region




Note: Charts show more than 100 per cent because the price can be set by more than one generator at a time.

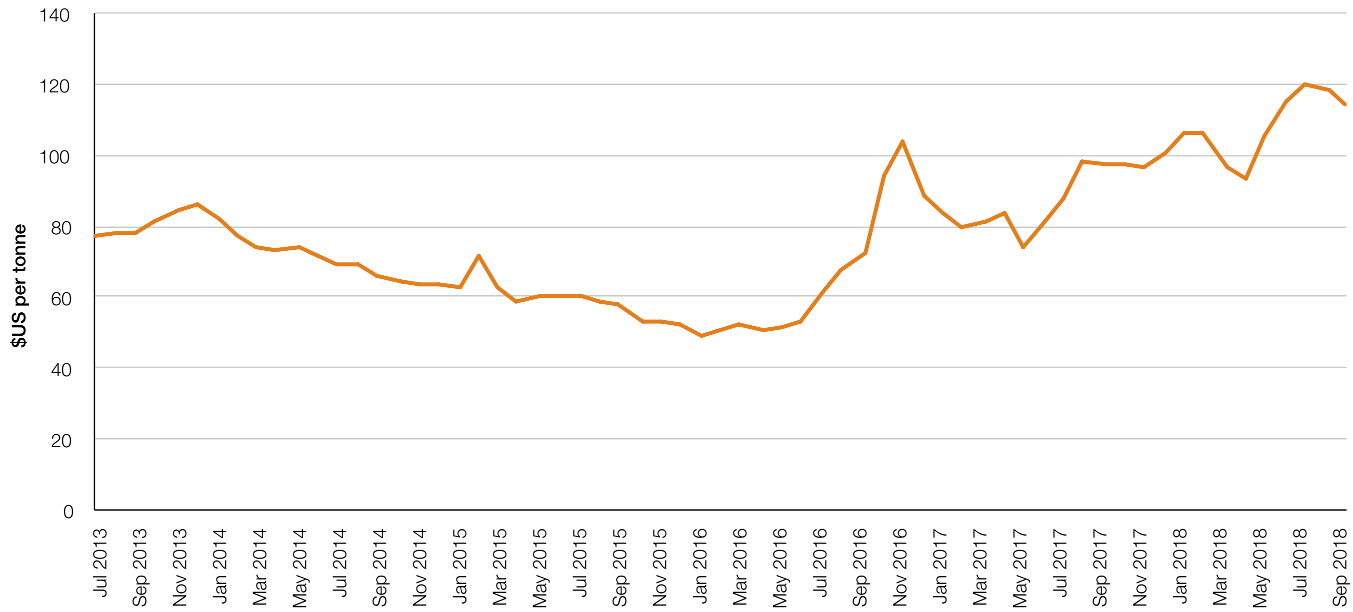
Source: AEMO data, AER analysis.

## Figure 2.8 Spot market gas price


Notes: Adelaide, Brisbane and Sydney Short Term Trading Market hub prices are average daily ex ante gas prices by month; Victorian Declared Wholesale Gas Market prices are average daily weighted prices by month. Wallumbilla prices are volume weighted average prices. The Wallumbilla Gas Supply Hub is a voluntary market and does not see trades every day. Averages are calculated only over the days trading occurred.

Source: AEMO data, AER analysis.

## Figure 2.9 Newcastle thermal coal index




Notes: The globalCOAL Newcastle price index (NEWC Index) is a reference price for spot thermal coal at the Newcastle Port in NSW.

Source: globalCOAL www.globalcoal.com.

## 2.4 The costs of maintaining the frequency of the system have also increased

Frequency control ancillary services (FCAS) are used to maintain the frequency of the system (box 2.3). The cost of these services increased in recent years, driven by factors including the changing generation technology mix.

FCAS costs are small compared with the cost of energy but since 2015 they have been increasing. Before September 2015, local FCAS costs averaged less than 0.5 per cent of NEM energy costs but since then they have tripled on average and have reached as high as 3 per cent in October 2015 (figure 2.10).

FCAS costs have increased for both regulation and contingency services. The increase also occurred at both a local and global level. South Australia in particular experienced a significant increase in local FCAS costs since new requirements were imposed by the Australian Energy Market Operator (AEMO) in late 2015 (figure 2.11).

The changing generation technology mix has contributed to rising FCAS costs. Several coal fired generators that traditionally provided FCAS, such as the coal fired Northern power station in South Australia, have exited leading to less supply in the market. Until recently, renewable generation (wind and solar) has not provided these services. However, the Hornsdale wind farm and the Hornsdale power reserve (battery) in South Australia now provide FCAS.

Tasmania has historically provided low cost global FCAS. However, unplanned outages on the Basslink interconnector between Tasmania and the mainland (from December 2015 to June 2016 and again from March to June 2018) reduced global FCAS supply and put upward pressure on global FCAS costs. AEMO also imposed limits on the amount of regulation services Tasmania is permitted to provide to the mainland (to better manage system security across the NEM).

Increased local requirements and a lack of competitive pressure on South Australian participants contributed to the increase in local FCAS costs in that region, but it appears these conditions are unlikely to be sustained as new participants have entered the market and the requirement for additional local services has been removed (section 4.3).

### Box 2.3 What are frequency control ancillary services?

Frequency control ancillary services (FCAS) maintains the frequency of the electrical system within acceptable limits (around 50 hertz) by adjusting the output of generators. FCAS is managed by the Australian Energy Market Operator (AEMO) as part of the dispatch process. Participants can register to provide FCAS services and make offers to AEMO to provide these services in the same way as they provide energy offers. AEMO determines which generators provide both energy and FCAS at lowest cost (known as co-optimisation), and issues instructions to generators.

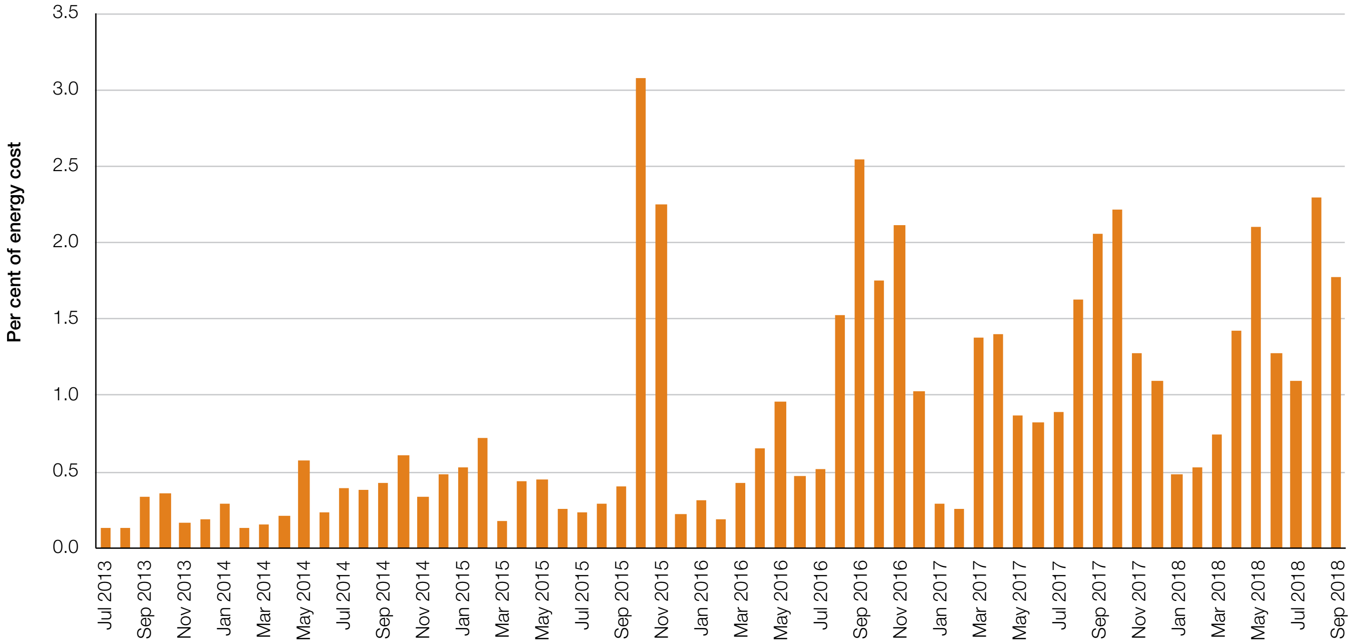
FCAS can comprise both 'global' and 'local' requirements. The majority of the time FCAS can be shared, over the interconnectors, between all regions (global service). When there is a credible risk of at least one region separating from the rest of the national electricity market, such as when there is a potential loss of an interconnector, local FCAS requirements are established to ensure that should the separation occur each sub region remains stable. This is most likely to occur in the regions at the ends of the network (Queensland, South Australia and Tasmania).

There are two general categories of FCAS:

- *regulation services* (raise and lower), which continuously adjust to small changes in frequency
- *contingency services* (6 second, 60 second and 5 minute, each with raise and lower), which are called upon in response to more major changes in frequency.

The costs of FCAS are recovered from generators and consumers.

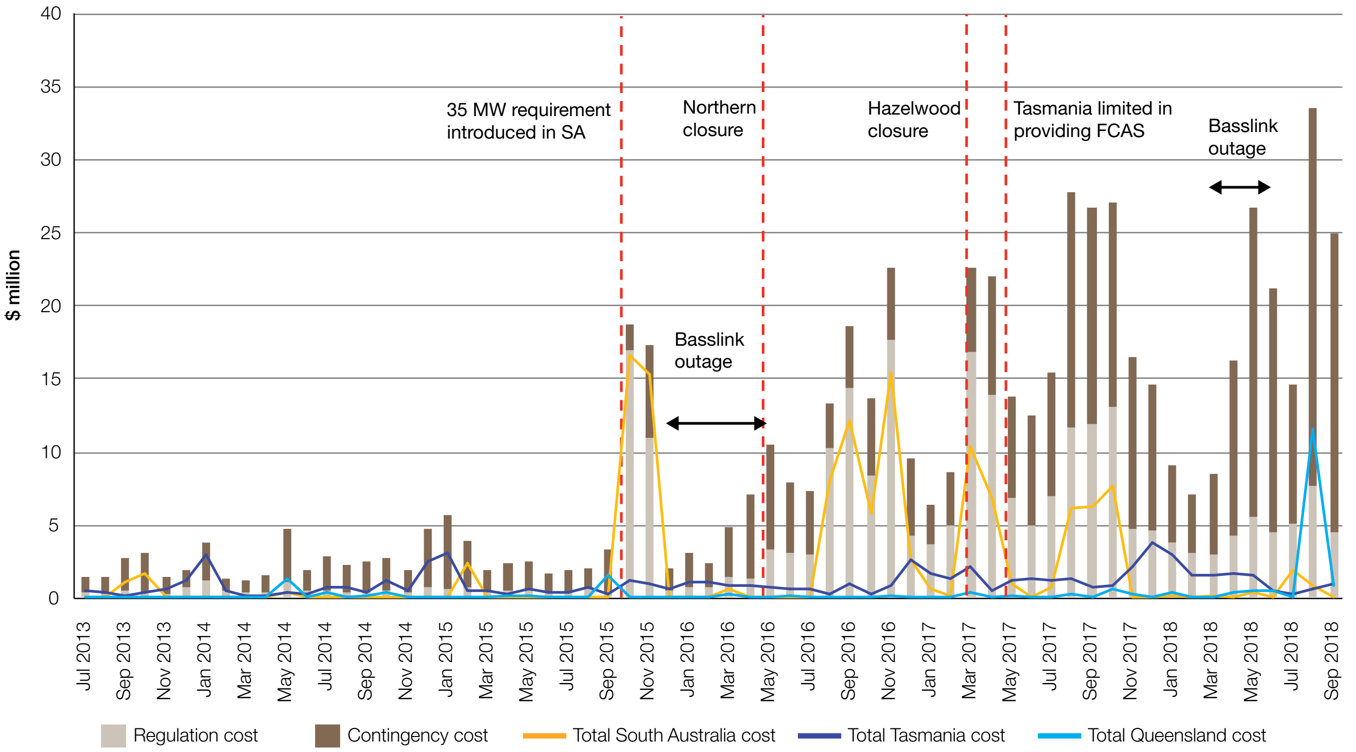
### Figure 2.10 FCAS costs as a per cent of energy cost, NEM




Notes: FCAS costs are the sum of total costs for each ancillary service for the NEM, calculated by multiplying regional price with the regional dispatch of each service for all regions. Energy cost is the sum of energy turnover in all regions, calculated by multiplying spot price by native demand for all trading intervals then dividing by two. AER defines native demand as the sum of initial supply and total intermittent generation in a region.

Source: AEMO data, AER analysis.

### Figure 2.11 Comparison of ancillary service costs—Global, and local for South Australia, Tasmania and Queensland, 2013 to 2018




Source: AEMO data, AER analysis.

# 3. Does the market structure support efficient and competitive markets?

### Key points

- Some aspects of the current market structure may make it more susceptible to uncompetitive outcomes.
- A few large vertically integrated participants control significant generation capacity and output in each region of the national electricity market (NEM). Ownership among fast response 'flexible' generation is also concentrated.
- Interconnectors allow imports from neighbouring regions, providing some competitive constraint in each region. But inter-regional competition is limited by the capacity of the interconnectors between each region.
- The output of a few large participants is necessary to meet demand in most regions a significant proportion of the time, even accounting for imports. While participants may have an ability to exercise market power at times, they may not have an incentive to do so. Incentives to exercise market power are influenced by a range of factors, including exposure to spot prices and government intervention.
- Contract markets are an important feature of the market for participants to manage price risk. Analysis of public data suggests liquidity has fallen in recent years and the South Australian market is illiquid.

The ownership structure of the market influences competitive rivalry in the market. A market with capacity controlled by a small number of generators is more susceptible to uncompetitive outcomes than a market with many participants. A generator is more likely to be able to exercise market power in a market with few participants, especially during periods of limited interconnector capacity. That said, the *ability* to exercise market power is distinct from *incentives* to exploit that power. A participant's incentives will be influenced by a range of factors including its exposure to spot or contract prices.

This chapter focuses on aspects of the market structure that may affect competitive and efficient outcomes:

- Section 3.1 shows a few large participants control a significant proportion of generation in each region.
- Section 3.2 explains imports from neighbouring regions provide some competitive pressure.
- Section 3.3 finds even taking imports into consideration, the output of the largest participants is often needed to meet demand.
- Section 3.4 concludes it is not necessarily profitable for a participant with market power to exercise it.
- Section 3.5 goes on to assess whether contract markets are sufficiently liquid to support effective risk management.
- Section 3.6 explores issues in demand response.

## 3.1 A few large participants control significant generation in each region

High market concentration may provide opportunities to exercise market power. We use some standard metrics to assess market concentration in each region of the NEM (box 3.1).

## Box 3.1 How do we assess concentration?

Market concentration refers to the number and size of participants in a market. A concentrated market has a high proportion of capacity controlled by a small number of generators and is more susceptible to outcomes that are not competitive. Market concentration can be measured using various metrics.

**Market share**

Market share is the simplest measure. We measure market share using capacity and output:

- Market share by *capacity* measures a participant's share of total registered capacity on a given date. It is a good overall measure of total market capacity. However, it does not account for plant outage or how different types of plant are used (for example, baseload generator and peaking generator capacity are treated equally). Nor does it account for other factors that may affect output, such as transmission constraints.
- Market share by *output* measures a participant's share of annual energy delivery. It better reflects the nature of a participant's generation fleet and market outcomes. But it doesn't account well for high capacity plant with an ability to respond to peak prices, but operated infrequently.

**Herfindahl Hirschman Index (HHI)**

HHI is a useful metric to summarise market concentration, by tallying the sum of squared market shares of all firms in a market. The index can range from zero (in a market with many small firms) to 10 000 for a monopoly. By squaring market shares, the HHI highlights the impact of large firms. The higher the HHI, the more concentrated the market.

We calculated HHI using *bid availability* or the capacity each generator offered, every 5 minutes. Unlike installed capacity or output measures, bid availability accounts for outages, fuel availability and bidding behaviour and provides a dynamic assessment of the levels of concentration in the market based on changing market conditions.

### 3.1.1 Ownership in each region is concentrated

A few large participants control a significant proportion of generation in each region of the NEM. The two largest participants in each region account for over half of total capacity (figure 3.1) and two thirds of total output (figure 3.2), except in South Australia which is slightly less concentrated. The most concentrated regions are Tasmania and Queensland. The state government owned Hydro Tasmania is the only generator in Tasmania. In Queensland, the two largest generators are Stanwell and CS Energy (state government owned). Together they account for 66 per cent of capacity and 74 per cent of output.

New South Wales (NSW), Victoria and South Australia are also concentrated. The three largest participants account for over 75 per cent of capacity and 80 per cent of output in each of these regions.[11] The three largest participants by output in each region are:

- AGL Energy, Origin Energy and EnergyAustralia in NSW
- AGL Energy, EnergyAustralia and Alinta Energy in Victoria
- AGL Energy, Origin Energy and Engie in South Australia.

In fact, AGL Energy accounts for a significant portion of *total* NEM capacity and output—around 20 per cent and 25 per cent respectively. While there are more participants in the NEM than in an individual region, even in a connected NEM-wide market, a few large participants still hold a considerable market position.

Snowy Hydro accounts for a relatively small share of output in NSW and Victoria, but it accounts for the third largest share of capacity in both regions (figure 3.1). This is because its fleet comprises hydroelectric generators with limited water availability and peaking gas plant, which typically operate less frequently. Snowy Hydro therefore provides competitive constraint and competition at peak times. We discuss the concentrated ownership of fast response flexible generation in section 3.1.2.

While some consolidation has occurred over the past decade, concentration in the NEM has not changed significantly in recent years, despite some plant retirements:

- The Queensland Government restructured its three generators into two in 2011.[12]
- In Victoria, AGL Energy acquired full control of Loy Yang A in 2012 and Engie exited the region when it closed the Hazelwood power station and sold Loy Yang B in 2017.
- In South Australia, Alinta Energy exited the region in 2016 when it closed the Northern and Playford power stations.
- The Tasmanian Government transferred Aurora Energy's generation assets to Hydro Tasmania in 2013. Hydro Tasmania now controls all generation in Tasmania.

11 In NSW AGL Energy, Origin Energy and EnergyAustralia control 83 per cent of output. In Victoria AGL Energy, EnergyAustralia and Alinta Energy control 89 per cent of output. In South Australia AGL Energy, Origin Energy and Engie control 82 per cent of output.

12 On 1 July 2011, Tarong Energy became a wholly-owned subsidiary of Stanwell Corporation.

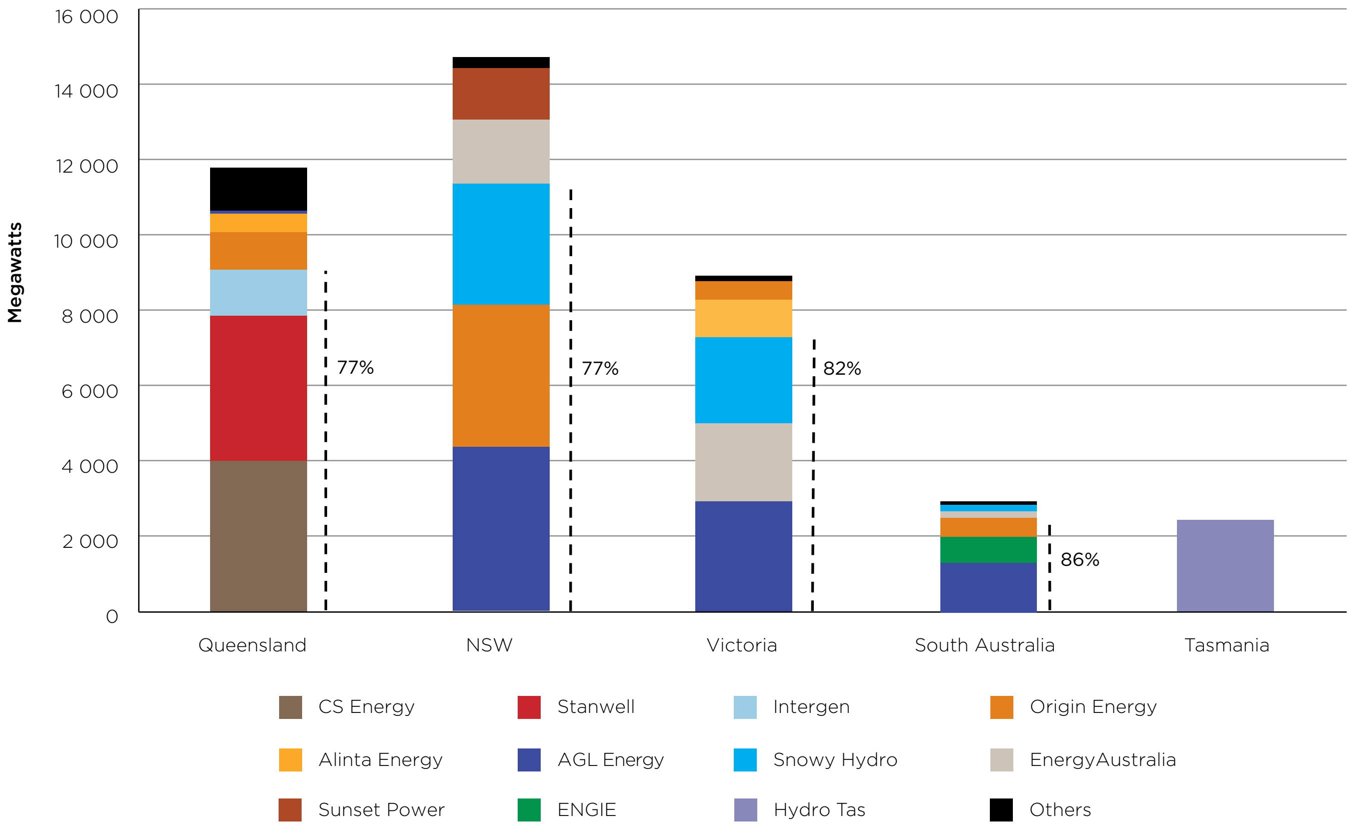
AGL Energy increased its ownership of generation assets across the NEM in 2014 by purchasing the Bayswater and Liddell coal-fired power stations from the NSW Government. In addition to acquiring existing plants, AGL Energy, Origin Energy and EnergyAustralia control nearly 40 per cent of all new capacity since 2013–14, either through direct build or by entering into power purchase agreements (PPA) with power station owners.[13] This new capacity has been almost exclusively wind and solar.

As well as using market share, we used the Herfindahl–Hirschman Index (HHI) to measure market concentration (box 3.1). Our HHI analysis uses annual average real time bid availability to measure concentration. Our regional HHI analysis does not account for competition provided by imports from other regions and therefore overstates the risks of uncompetitive outcomes.

The US Federal Energy Regulatory Commission merger policy thresholds broadly categorise a HHI below 1000 as not concentrated, a HHI of 1000 to 1800 as moderately concentrated, and a HHI above 1800 as highly concentrated.[14] The Australian Competition and Consumer Commission (ACCC) merger guidelines indicate the ACCC is less likely to identify horizontal competition concerns when the post-merger HHI is less than 2000.[15] We have not determined our own HHI concentration thresholds, but use HHI to compare the degree of concentration over time and between regions.

The average HHI by availability is over 2000 for each region of the NEM, with no significant variation in recent years (figure 3.3). But there is significant variation from the average when examining individual dispatch intervals. The lowest and highest single HHI value for any mainland region in 2017–18 was 1058 and 3192 respectively, both in South Australia (figure 3.4).[16] This result shows market concentration is variable and influenced by factors including plant outages, fuel availability and bidding behaviour in response to different levels of demand and prices.

**Figure 3.1 Market share by capacity, January 2018**




Notes: Capacity figures refer to summer capacity at 31 January 2018. Capacity for intermittent generators is adjusted for an average contribution factor. Interconnector capacity is not included. Trading rights for each generator are attributed to the organisation that has control over the generation output. In the case of generators with power purchasing agreements (PPA), the trading rights are attributed to the organisation that receives the energy under the PPA.

Source: AEMO data, AER analysis.

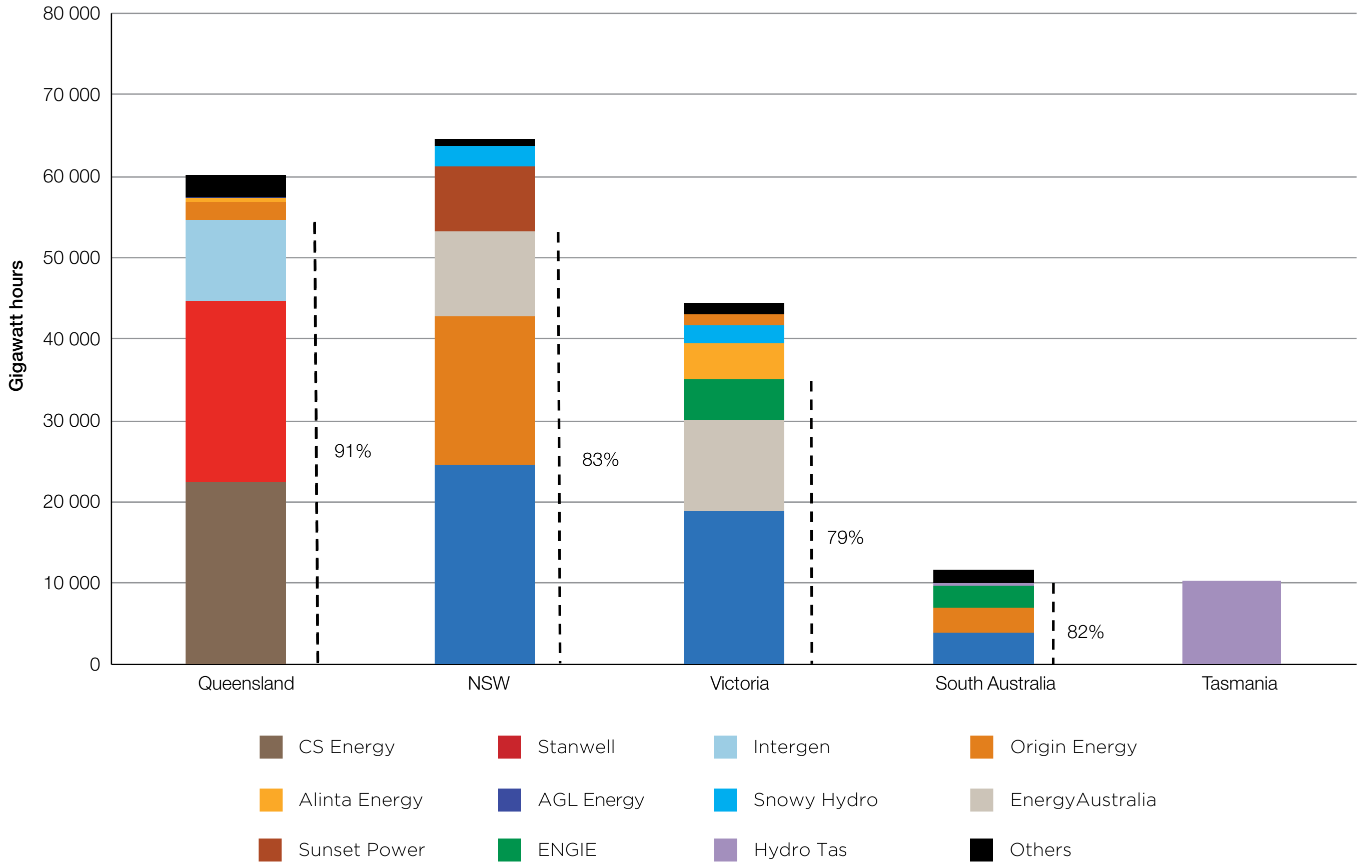
13 AEMO Generation information, AER analysis. As at November 2018. Trading rights for each generator are attributed to the organisation that has control over the generation output. In case of generators with PPAs, the trading rights are attributed to the organisation that receives the energy under the PPA.

14 United States Federal Energy Regulatory Commission (FERC), *Merger Policy Statement*, December 1996, p. 62. The market concentration thresholds used by FERC are based on the market concentration thresholds established by the Department of Justice/Federal Trade Commission Merger Guidelines.

15 ACCC, *Merger Guidelines*, November 2008 (updated 2017), p. 35.

16 HHI was calculated using market share of bid availability at 5 minute intervals, by trading rights.

## Figure 3.2 Market share by output, 2017–18




Notes: Annual output (energy dispatched) by trading rights in each NEM region, include scheduled and semi-scheduled generation. These are attributed to the organisation that has control over output, including PPAs. Interconnector flows are not included. In Victoria, Alinta Energy purchased Loy Yang B from Engie in January 2018. Output from Loy Yang B prior to the sale is attributed to Engie, output after the sale is attributed to Alinta Energy.

Source: AEMO data, AER analysis.

## Figure 3.3 Average bid availability HHI

| | 2013–14 | 2014–15 | 2015–16 | 2016–17 | 2017–18 |
|---|---|---|---|---|---|
| Queensland | 2245 | 2182 | 2199 | 2297 | 2371 |
| NSW | 2089 | 2264 | 2313 | 2430 | 2272 |
| Victoria | 2300 | 2246 | 2266 | 2296 | 2393 |
| South Australia | 2226 | 2140 | 2270 | 2482 | 2210 |
| Tasmania | 10000 | 10000 | 10000 | 10000 | 10000 |
| NEM | 913 | 1061 | 1123 | 1168 | 1135 |

Note: HHI is calculated using market share of bid availability in each region, by trading rights using all 5 minute dispatch intervals.

Source: AEMO data, AER analysis.

**Figure 3.4 Variability in bid availability HHI, 2017–18**

| | Minimum | Average | Maximum |
|---|---|---|---|
| Queensland | 2 052 | 2 371 | 3 015 |
| NSW | 1 984 | 2 272 | 2 810 |
| Victoria | 2 022 | 2 393 | 3 086 |
| South Australia | 1 508 | 2 210 | 3 192 |
| Tasmania | 10 000 | 10 000 | 10 000 |

Note: HHI is calculated using market share of bid availability in each region, by trading rights using all 5 minute dispatch intervals.

Source: AEMO data, AER analysis.

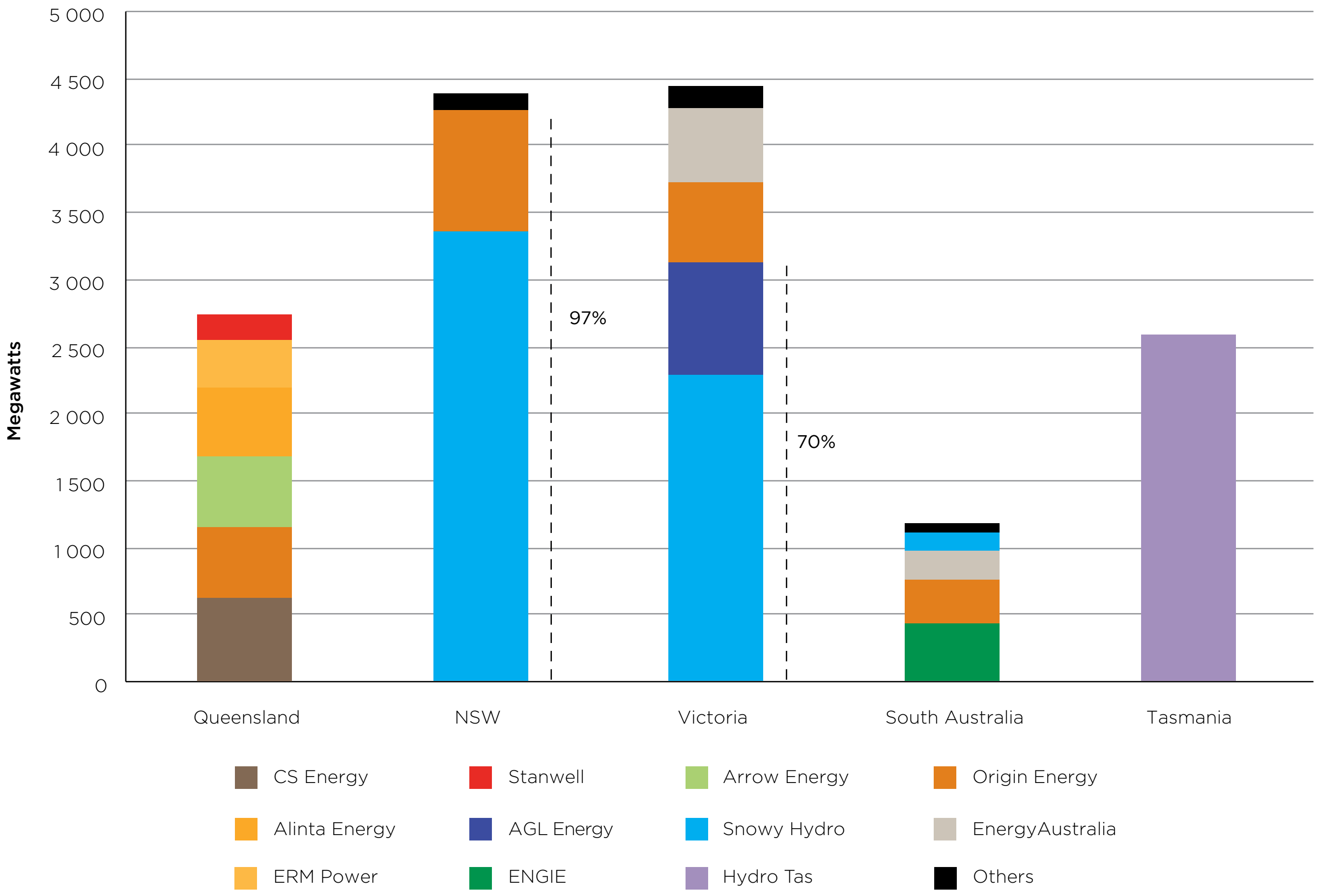
### 3.1.2 Fast response 'flexible' generation ownership is also concentrated

A few participants control significant flexible generation capacity in NSW, Victoria and Tasmania.

As stated earlier, concentration is highest in NSW and Victoria because the capacity of Snowy Hydro accounts for the vast majority of flexible capacity (figure 3.5). The other providers in those regions are AGL Energy, EnergyAustralia and Origin Energy. Ownership of flexible generation is more diverse in Queensland and South Australia, with five key participants in each region. Hydro Tasmania is the only provider of generation in Tasmania, flexible or otherwise.

The need for fast response generation is likely to grow in response to the increasing penetration of intermittent generation (section 2.1.1). There are proposals for additional flexible capacity (section 5.1.4), the largest being Snowy 2.0 (up to 2000 MW) and Tasmania's Battery of the Nation (up to 2500 MW). We will monitor developments in the demand and supply of flexible capacity and any possible implications for competition.

**Figure 3.5 Providers of flexible generation capacity by region, 2017–18**




Notes: Installed capacity of flexible generation by trading rights in each NEM region. These are attributed to the organisation that has control over output, including PPAs, except Origin Energy's long term PPAs over Braemar 1 (owned by Alinta Energy) and Braemar 2 (owned by Arrow Energy) in Queensland. Flexible generation includes open cycle gas turbines, diesel reciprocating engines, hydroelectric generators (gravity, pump storage, run of river) and battery storage. Temporary diesel generators belonging to SA Power Networks and the portion of Hornsdale power reserve reserved for emergency are not included as they are not active market participants.

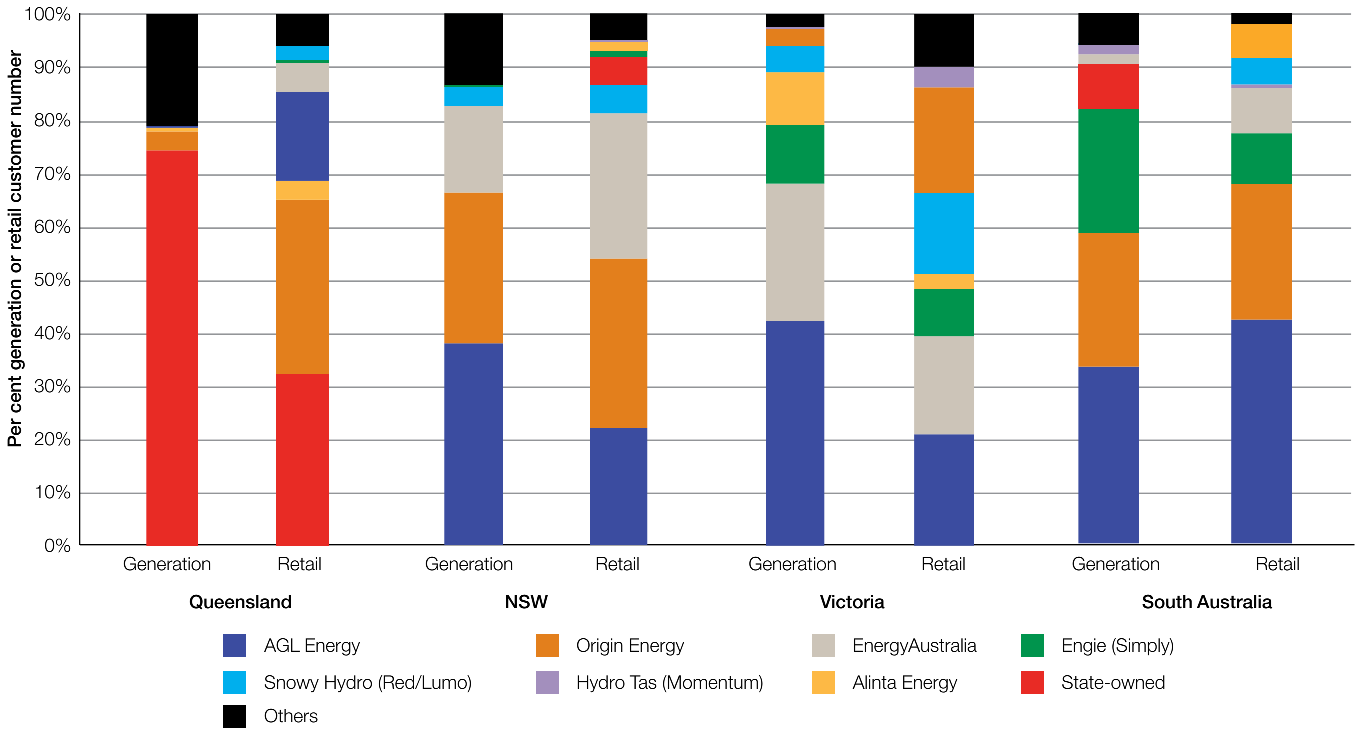
Source: AEMO registration and exemption list, accessed August 2018.

### 3.1.3 Vertical integration is a key feature of the NEM

Vertical integration occurs when a market participant combines generation and retail operations. It is a key feature of the Australian electricity market. Figure 3.6 shows participants' share of generation output against their share of small retail customers. This measure of vertical integration does have some limitations as it doesn't account for large customers or load. However, it does provide some indication of the extent of vertical integration in the NEM:

- In NSW, four vertically integrated participants accounted for 87 per cent of small retail customers and 86 per cent of generation output.
- In Victoria, six vertically integrated participants accounted for 88 per cent of small customer numbers and 97 per cent of generation output.
- In South Australia, four vertically integrated participants accounted for 86 per cent of small customers and 84 per cent of generation output.
- In Queensland, the state government owns the retailer, which supplies electricity at regulated prices to customers in rural and regional Queensland, and two generation companies.

**Figure 3.6 Vertical integration in the NEM, 2017–18**




Notes: The black segments represent non-vertically integrated participants. Generation share is based on 2017–18 annual output (energy dispatched) by trading rights, includes scheduled and semi-scheduled generation. Shares are attributed to the organisation that has control over output, including PPAs. Interconnector flows are not included. Retail share for Queensland, NSW and South Australia is based on residential and small business customer numbers at June 2018. Retail share for Victoria is based on residential and small business customer numbers at June 2017.

Sources: AEMO, AER and Essential Services Commission (Victoria) data, AER analysis.

The degree of vertical integration in the NEM has increased over the past five years. AGL Energy, Origin Energy and EnergyAustralia who supply around 70 per cent of retail electricity customers[17] expanded their share of total generation output from 37 per cent in 2013–14 to 50 per cent in 2017–18. Engie was the last merchant generator south of Queensland. When it closed Hazelwood power station and sold Loy Yang B to a vertically integrated participant, this signalled the end of the independent generator business model in Australia.

The trend towards increased vertical integration reflects the natural internal hedge that vertical integration provides against spot price volatility. It also has the advantage of lower transaction costs, reduced counter party risk and lower financing costs when looking to expand. Vertical integration can affect incentives to exercise market power as well as contract market liquidity (sections 3.4.1 and 6.1.1).

## 3.2 Flows between regions provide some competitive pressure

Each region in the NEM is connected by high voltage transmission lines that enable energy to flow between neighbouring regions (box 3.2). Trade between regions over the interconnectors provides some competitive constraint on participants within a region.

17 Based on residential and small business customer numbers in Queensland, NSW and South Australia at June 2018, and Victoria at June 2017.

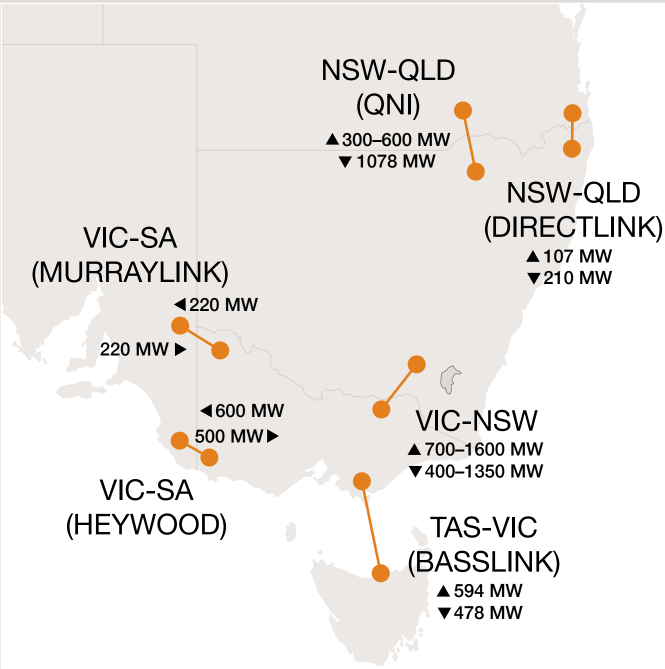
## Box 3.2 Interconnectors in the NEM

Transmission interconnectors enable energy transfers between the national electricity market's (NEM) five regions (figure 3.7). Interconnectors deliver energy from lower price regions to higher price regions. They also increase the reliability and security of the power system by enabling demand in one region to be met by generation from an adjacent region.

The ability of generators to supply energy to other regions is limited by the capacity of the transmission network. This capacity can change depending on the direction of flow, outages on the network or other physical constraints and limits the Australian Energy Market Operator imposes to manage system security.

An interconnector is constrained when the flow across it reaches its technical limit. When an interconnector is constrained, cheaper sources of generation in one region cannot replace more expensive generation in another, effectively separating those regions into separate markets.

**Figure 3.7 Interconnectors in the NEM**




Source: AEMO.

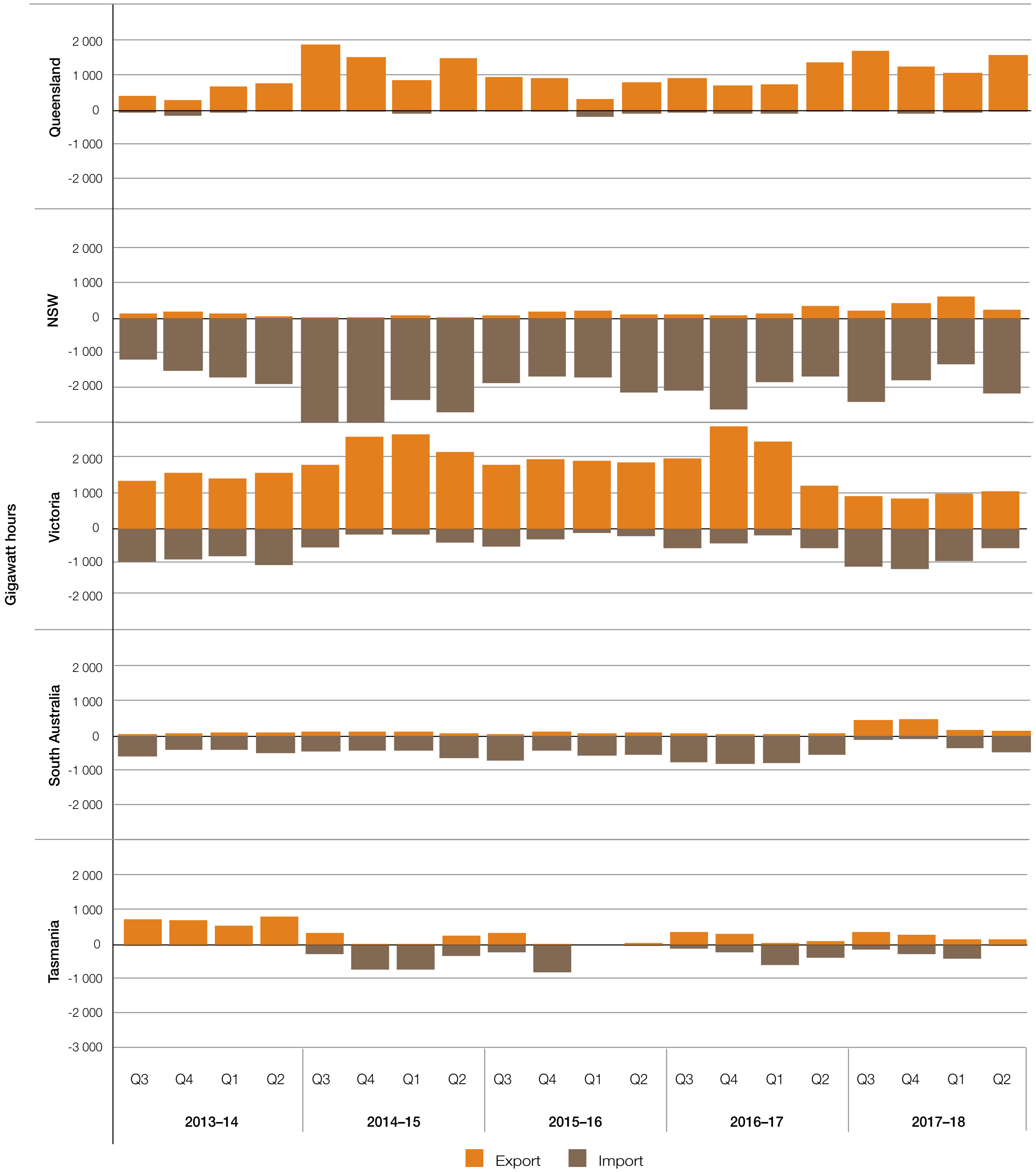
### 3.2.1 Trade between regions can provide competitive pressure

Interconnector flows show there is trade between regions (figure 3.8). Subject to physical limitations, energy typically flows from regions with lower prices to regions with higher prices. In 2017–18, for example, Queensland had the lowest prices in the NEM and was a net exporter to NSW, providing some competitive constraint in NSW. When energy flows freely between regions, the prices in those regions tend to be aligned.

In an efficient market, as prices change, flows change to meet market needs. Over the past five years Victoria and Queensland were the principal exporters in the NEM due to abundant low priced generation from brown coal in Victoria and low fuel costs and surplus capacity in Queensland. NSW and South Australia have typically been net importers due to their dependence on higher priced fuels.

In 2017–18 flows between regions changed, largely as a result of Hazelwood power station in Victoria closing. Reduced production of low cost energy from brown coal resulted in lower exports from Victoria and higher prices. Exports from Queensland increased as the Queensland black coal generators' output became more competitive relative to Victoria. In 2017–18, Queensland overtook Victoria as the highest exporting region in the NEM.

## Figure 3.8 Regional interconnector flows—exports and imports




Source: AEMO data, AER analysis.

### 3.2.2 But competition between regions is limited by interconnector capacity

While inter-regional trade provides competition between neighbouring regions, the amount of competition is limited by the physical capacity of the interconnectors between regions.

Price separation between regions generally occurs when there is not enough interconnector capacity to equalise the spot price between a higher priced and a lower priced region. Prices in the importing region tend to be higher than prices in the exporting region. Several factors can affect interconnector constraints and price alignment, including network outages, and upgrades and limitations put in place to manage the technical operation of the grid and maintain system security. When the interconnectors between adjacent regions are constrained and inter-regional competition is limited, the risk of uncompetitive outcomes due to market concentration in a region increases.

Conversely, when interconnectors are not constrained, prices across regions tend to align (altered only by network losses). This means price alignment rates can be used as an indicator of inter-regional competition. Average price alignment rates across the mainland NEM regions over the past five years have been variable—as low as 24 per cent in quarter four 2016 to as high as 75 per cent in quarter three 2017 (figure 3.9).

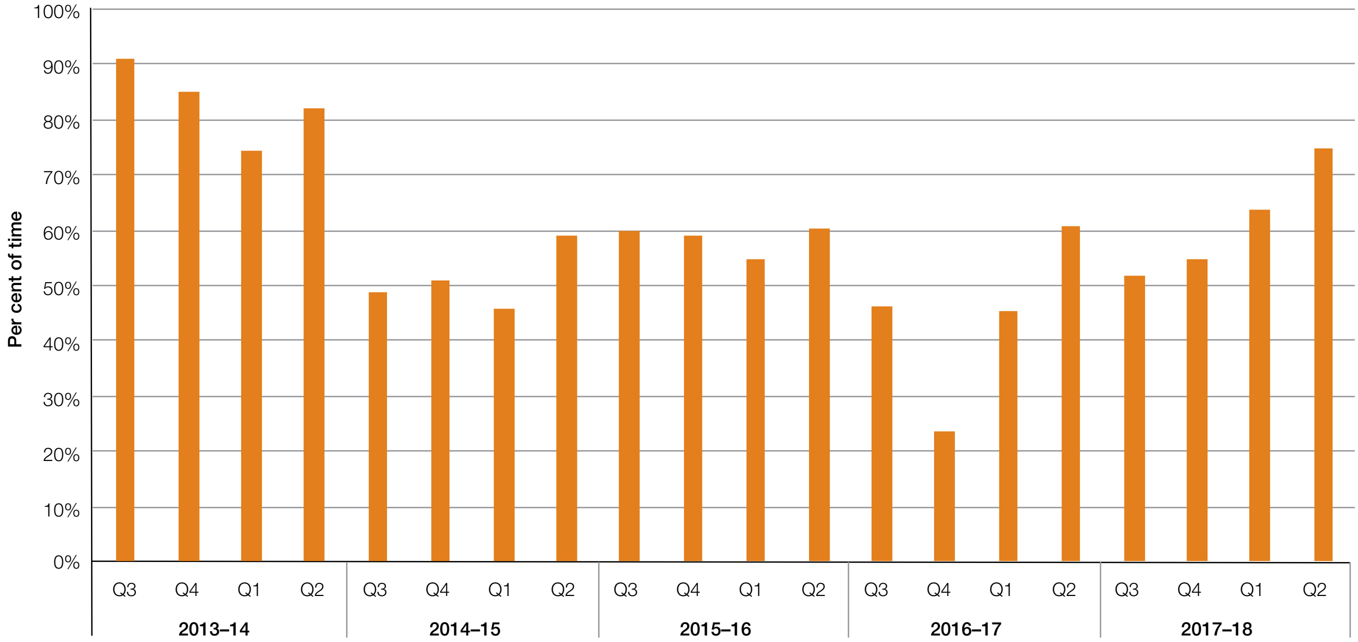
Interpreting alignment rates as an overall indicator of competition between regions requires care. The alignment rates between South Australia and Victoria improved when the Hazelwood power station closed, for example, but the higher alignment rates between the regions did not indicate increased competition. Rather, when Hazelwood closed in March 2017, less energy was available to share between Victoria and South Australia, and as a result the Heywood interconnector operated at its technical limit less frequently (the step down in the yellow line in figure 3.10). Since Hazelwood closed, Queensland, NSW and Victoria have each been price aligned with another region over 95 per cent of the time (figure 3.10). South Australia has been price aligned with Victoria 90 per cent of the time.

Less interconnected regions may face less competitive pressure from inter-regional trade than more interconnected regions. Regions with only one neighbour are more likely to reach their total import limits (and prices move out of alignment) than more interconnected regions. South Australia, which is connected only to Victoria, reached its total importing limit (and prices separated) 28 per cent of the time on average in 2016–17. Tasmania reached its import limit 47 per cent of the time in the three years between 2014 and 2017 due to a major outage on the Basslink interconnector in those years and a lack of interconnection with other regions. NSW and Victoria on the other hand, are interconnected with more than one region and rarely reached their import limits (figure 3.10).

While interconnectors facilitate inter-regional competition, in considering future interconnector planning and investment, we should recognise that consumers ultimately pay the bill. To minimise the risk in over-investment (where consumers pay more than necessary) or under-investment (consumers experience lower reliability or higher than necessary wholesale prices), interconnector investment decisions currently undergo a rigorous cost-benefit analysis.

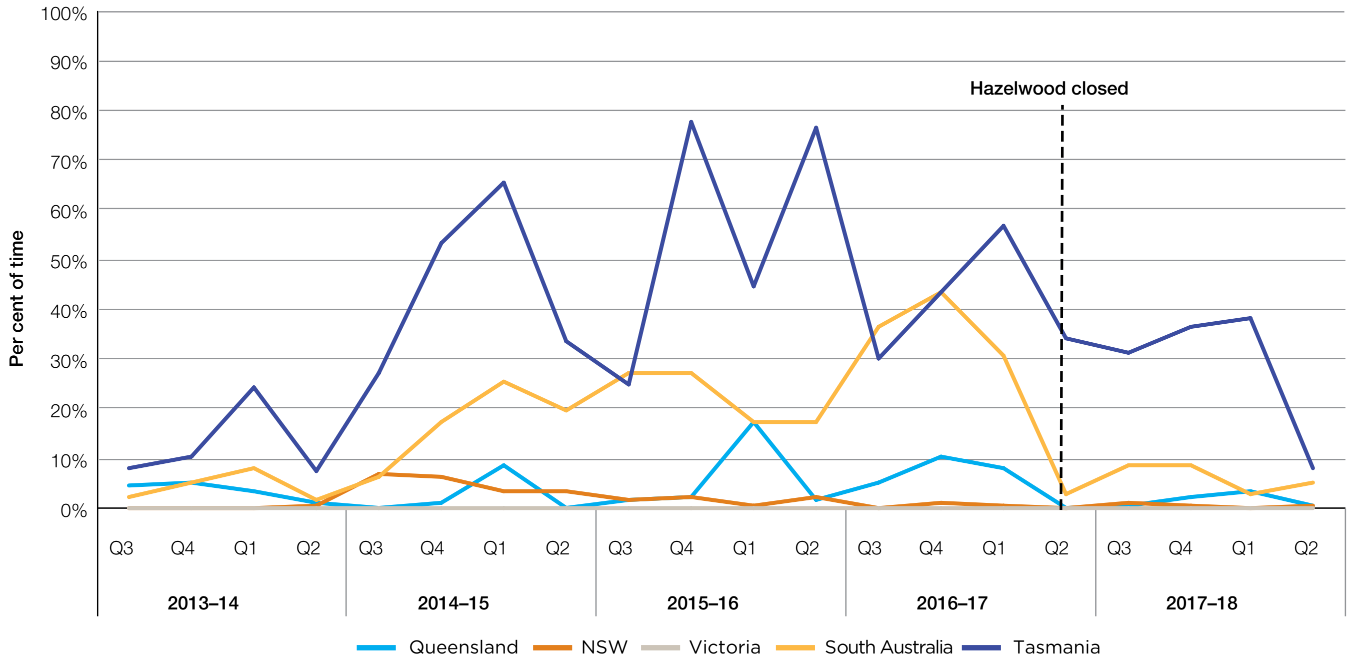
When the same large participants are present on both sides of an interconnector, competition from inter-regional trade may also be limited. AGL Energy, for example, accounts for 30–40 per cent of output in South Australia, Victoria and NSW. When the interconnectors between Victoria and South Australia are unconstrained, it is unlikely AGL Energy's generators in Victoria would actively compete against its generators in South Australia.

**Figure 3.9 Price alignment across mainland regions of the NEM**




Note: Based on 5 minute interconnector flows and limits.
Source: AEMO data, AER analysis.

**Figure 3.10 Percentage of time regions reach their total import limit**




Note: Based on 5 minute interconnector flows and limits.
Sources: AEMO data, AER analysis.

## 3.3 A few large participants are needed to meet demand, even with imports

In most regions, the output of a few large participants is necessary to meet demand for a significant proportion of the time, even accounting for the availability of imports. At these times, the large participants are considered ‘pivotal’ to meeting demand and may have an increased ability to exercise market power.

We quantify when the largest participants are pivotal to meeting demand in a region using residual supply index (RSI, box 3.3). RSI provides an understanding of whether the output of certain participants is required to meet demand. But a limitation of RSI analysis is its focus on whether a participant is able to raise prices rather than whether it is profitable for it to do so. Many factors can influence a participant’s incentives to exercise market power, including the extent to which it is vertically integrated and its contract position (section 3.4).

We calculated RSI-1, RSI-2 and RSI-3 for each mainland NEM region—for every trading interval in the past five years. Then we measured the percentage of time those RSI values fell below one—that is, when some generation from the one, two or three pivotal participants was needed to meet demand (figures 3.11–3.13).

The findings suggest:

- In *Queensland*, the largest participant (either Stanwell or CS Energy) is needed to meet demand around 20 per cent of the time. When both state owned generators, Stanwell and CS Energy, are considered together (RSI-2), some of their generation is needed to meet demand 100 per cent of the time. This implies the Queensland market may be susceptible to uncompetitive outcomes.
- In *NSW*, the largest participant is needed to meet demand around 3 per cent of the time (or around 10 days per year). More significantly, the two largest participants in NSW are needed to meet demand 80 per cent of the time. This makes the NSW market more susceptible to uncompetitive outcomes than markets with lower RSI values. Some output from one of the three largest participants is always needed to meet demand. The participants needed to meet demand in NSW are mostly likely to be AGL Energy, Origin Energy and Snowy Hydro, in that order.[18]
- In *Victoria*, the largest participant is needed to meet demand around 3 per cent of the time. Since the closure of Hazelwood power station, the two largest participants are pivotal more often (figure 3.12). Some generation from the two largest participants is now needed to meet demand 75 per cent of the time, up from 50 per cent before the closure. The three largest participants are always needed to meet demand. The pivotal participants in Victoria are mostly likely to be AGL Energy, EnergyAustralia and Snowy Hydro, in that order.[19]
- In *South Australia*, output from the largest participant was rarely required to meet demand in 2017–18. This was an improvement on the two years prior when it was needed around 4 per cent of the time. The two largest participants were needed to meet demand around 15 per cent of the time and the three largest around 70 per cent of the time. The largest participant(s) were less pivotal in 2017–18, in part because Engie brought Pelican Point’s second unit back online. The pivotal participants in South Australia are mostly likely to be AGL Energy, Engie and Origin Energy, in that order.[20]
- In *Tasmania*, Hydro Tasmania is always needed to meet demand.

18 AER, RSI analysis.

19 AER, RSI analysis.

20 AER, RSI analysis.

## Box 3.3 Measuring competition using residual supply index

Residual supply index (RSI) measures the extent to which one or more participants is 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other participants. In these circumstances, the participant must be dispatched (at least partly) to meet demand.

The RSI-1 measures the ratio of demand that can be met by all but the largest participant in a region.

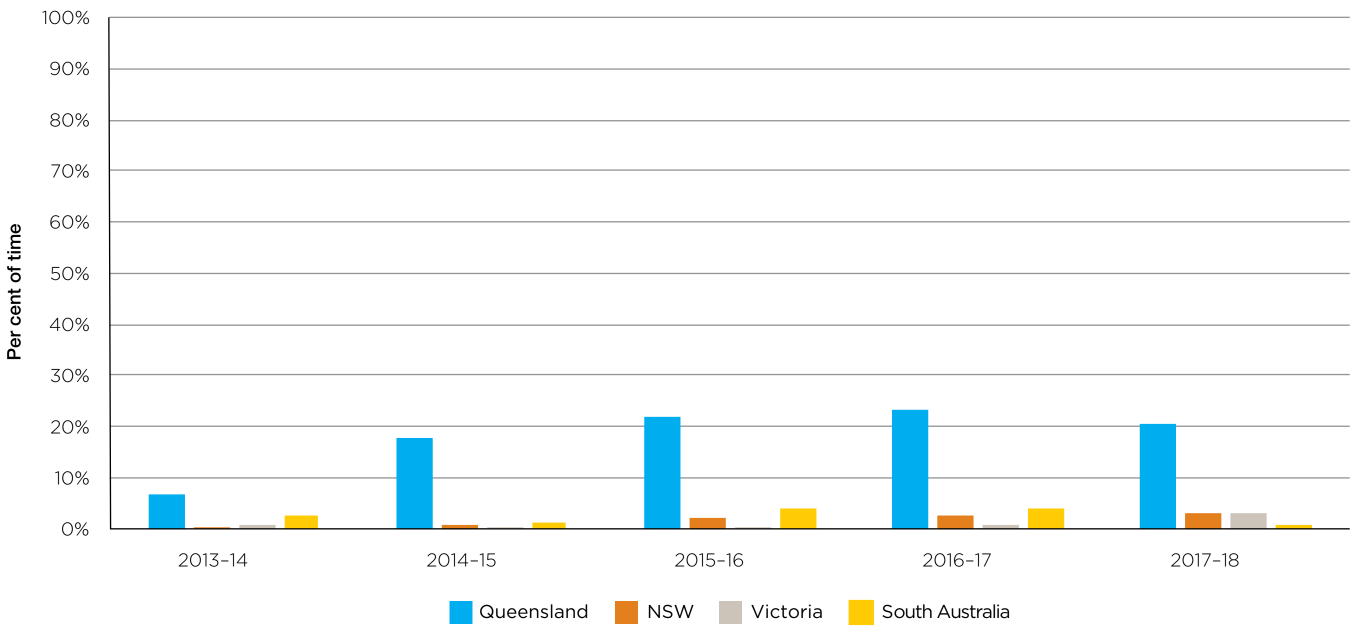
$$\text{RSI–1} = \frac{\text{total availability—largest participant's availability}}{\text{demand}}$$

An RSI-1 greater than one means demand can be fully met without dispatching the largest participant. An RSI-1 below one means the largest generator becomes pivotal to meeting demand. Various factors may cause the RSI to deteriorate, including a rise in demand, a decrease in available generation capacity, or an increase in the proportion of available capacity supplied by the largest participant.

RSI-2 or RSI-3 measures the ratio of demand that can be met by all but the two largest or three largest participants in a region. It is easier for one pivotal participant to exercise market power than two or three participants. But, RSI-2 and RSI-3 are still useful measures because they indicate the potential risk of coordinated effects among two or three participants. The fewer participants required to meet demand, the greater the risk these participants could implicitly or explicitly coordinate pricing or output decisions.

RSI analysis does not consider market features such as transmission constraints or ramp rate limitations.

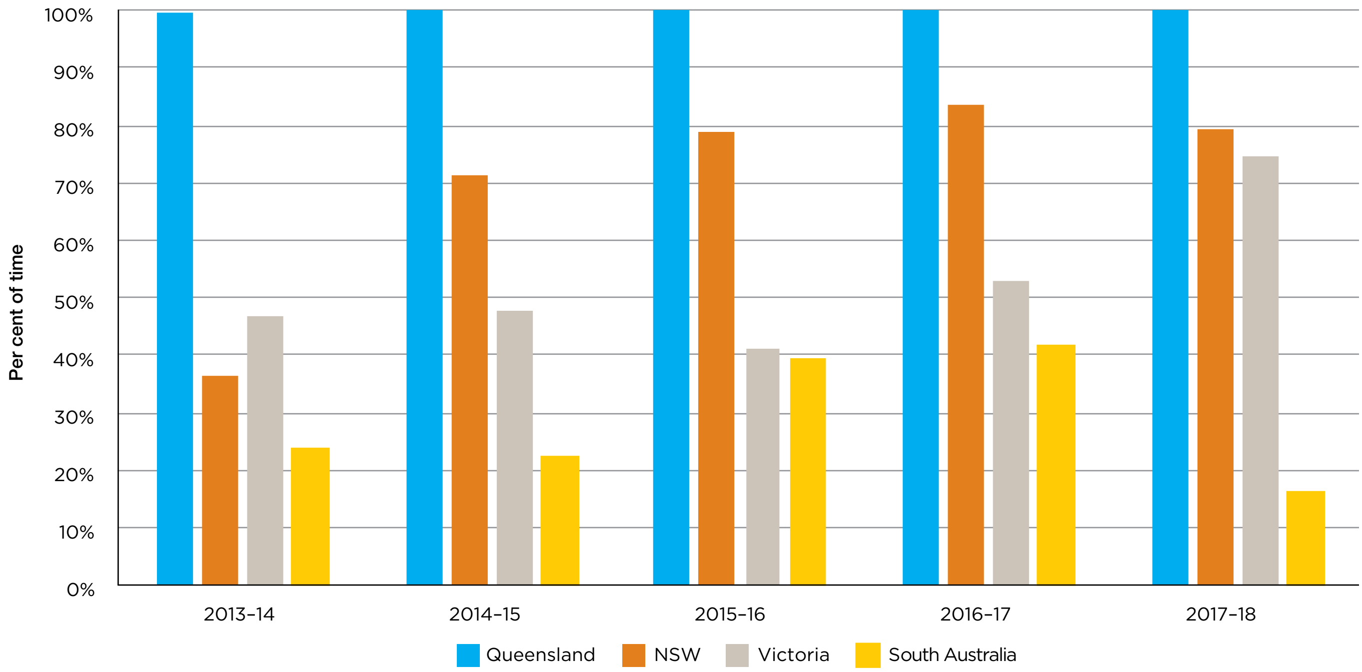
**Figure 3.11 Percentage of time some generation from the largest participant is needed to meet demand (RSI-1 below 1)**




Notes: By trading rights. Based on half hourly bid availability, includes maximum possible imports as available capacity. If an interconnector is forced to export, it is treated as additional demand in the region.

Source: AEMO data, AER analysis.

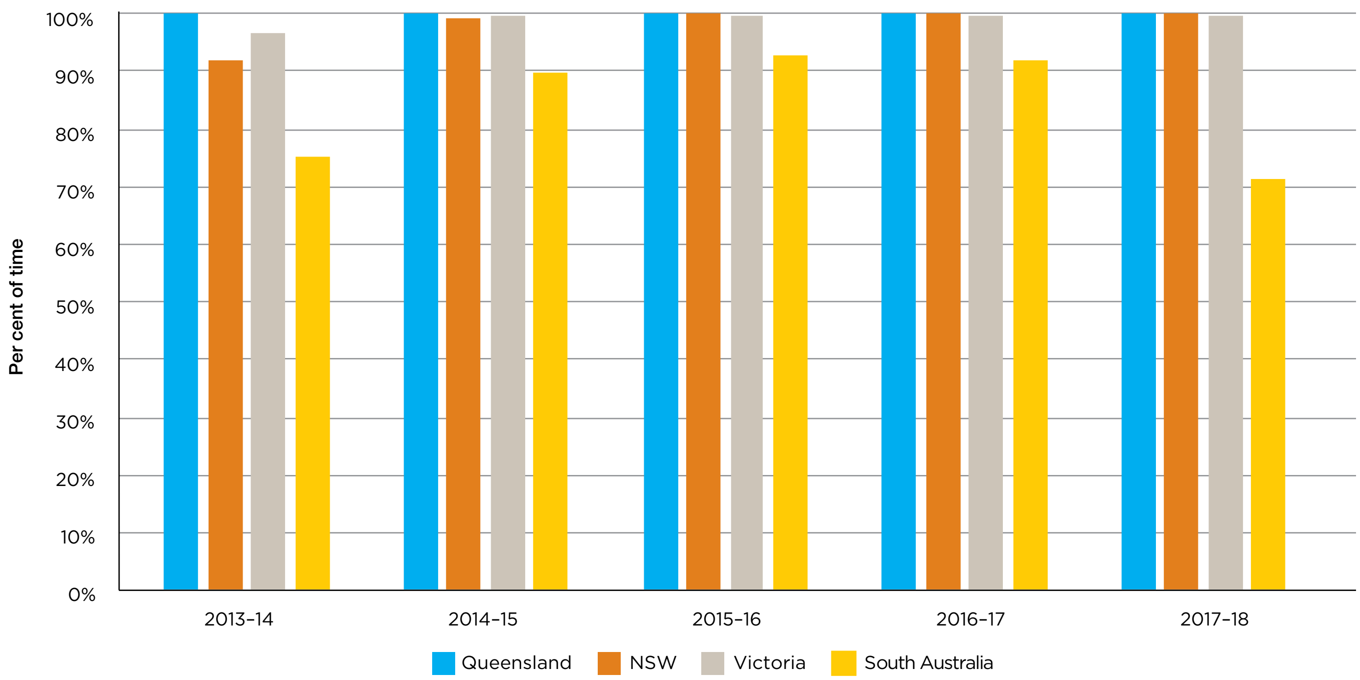
Figure 3.12 Percentage of time some generation from the two largest participants is needed to meet demand (RSI-2 below 1)




Notes: By trading rights. Based on half hourly bid availability, includes maximum possible imports as available capacity. If interconnector is forced to export, it is treated as additional demand in the region.

Source: AEMO data, AER analysis.

Figure 3.13 Percentage of time some generation from the three largest participants is needed to meet demand (RSI-3 below 1)




Notes: By trading rights. Based on half hourly bid availability, includes maximum possible imports as available capacity. If interconnector is forced to export, it is treated as additional demand in the region.

Source: AEMO data, AER analysis.

## 3.4 A participant may not have an incentive to exercise market power

A participant with the ability to exercise market power may not have an incentive to exercise that power. A participant's exposure to spot prices and actual or threatened government direction will affect its incentives to exercise market power.

### 3.4.1 A participant's exposure to spot prices impacts its incentive to exercise market power

A participant's incentives to exercise market power are influenced by the extent to which it is exposed to spot prices. Vertical integration (section 3.1.3) and contracting (section 3.5) reduce a participant's exposure to spot prices. Reduced exposure to spot prices, also reduces the profitability (and potentially raises the risk) of any economic or physical withholding (see box 4.1 for an explanation of withholding).

A participant that is fully contracted with very limited immediate exposure to spot prices is unlikely to profit significantly from a successful withholding strategy. While this participant will receive higher spot market revenue, it will also be required to pay the counterparty to its contract the difference between the spot price and the contract strike price. A withholding strategy could also be risky as the participant may price themselves out of the market and still be required to pay its counterparty. Similarly, if this participant is vertically integrated such that its generation exactly matched its load, then higher spot revenues for its wholesale business would be offset by higher costs for its retail arm. In the long term, however, higher spot prices could potentially be passed on to retail customers through renegotiated retail contracts or forward contracts could be renegotiated with a higher strike price.

We haven't assessed the extent to which participants are exposed to spot prices and how this might affect their incentives to exercise market power. While we have some information on the extent participants are vertically integrated, we do not have access to information on their contract positions. The ACCC and the Australian Energy Market Commission (AEMC) have made recommendations to improve transparency for over the counter (OTC) transactions (chapter 7).[21]

### 3.4.2 A participant may not exercise market power, as a result of government regulation or direction

A participant may not exercise market power due to government intervention or the threat of government intervention. Government intervention has affected state owned generators in Tasmania and Queensland.

In light of its monopoly position, the Tasmanian Government requires Hydro Tasmania to offer wholesale contracts to retailers at regulated prices (box 3.4). This arrangement limits Hydro Tasmania's incentive to exercise market power by increasing wholesale prices in the Tasmanian market because it must still meet obligations under the regulated contracts.

In Queensland, the two government owned participants (Stanwell and CS Energy) can exercise market power, due to their dominant market position but recent directions from the Queensland Government have limited their price spiking behaviour (section 4.2.1). Over the past five years rebidding resulted in price spikes and volatility. But this behaviour was reduced by an AEMC rule change[22] and effectively stopped in mid-2017 when the Queensland Government instructed Stanwell to put downward pressure on spot prices.[23] The ACCC recommended changes to address this problem, including that the Queensland Government should divide its generation assets into three generation portfolios to reduce market concentration.[24]

21 ACCC, *Retail electricity pricing inquiry—final report*, recommendation 6, July 2018, p. xviii.

22 AEMC, *Bidding in good faith—final rule determination*, 10 December 2015.

23 Acting Minister for Energy, Biofuels and Water Supply, Palaszczuk Government acting on electricity prices–Media release, July 2017.

24 ACCC, *Retail electricity pricing inquiry—final report*, July 2018, p. 93.

### Box 3.4 Contract pricing arrangement in Tasmania

In 2012, the Electricity Supply Industry Expert Panel concluded its review into the electricity supply industry in Tasmania. Among its recommendations, it proposed separating Hydro Tasmania's physical generation operations from its financial trading functions and transferring these trading functions to three specialised 'gentraders'.[25]

The Tasmanian Government chose instead to regulate wholesale contracts. Currently, the regulated contract price is linked to the Victorian price (as a competitive price) then adjusted to account for the supply–demand balance. If Tasmania is undersupplied, prices will be higher than in Victoria and vice versa. The Tasmanian Government has committed that by July 2021 it will remove the link to Victorian prices when setting the Tasmanian wholesale electricity price.[26]

Every week Hydro Tasmania calculates the regulated contract price. Retailers then nominate the volume of product they want to buy. Hydro Tasmania agrees to meet the request in full or else the available contracts are rationed. Rationing occurs when the regulated cost is below Victorian prices and is determined by existing market share. A retailer with 60 per cent market share gets 60 per cent of the ration. To prevent retailers potentially arbitraging prices with Victoria, Hydro Tasmania is only obliged to sell up to total demand in Tasmania.

## 3.5 Contract markets need to be liquid to support an efficient market

The NEM was designed with a contract market operating in conjunction with the spot market, so participants can efficiently hedge against volatile prices (box 3.5). To enable participants to easily buy and sell contracts to manage their risk, contract markets must be liquid. However, public data suggests trade in contract markets has fallen in recent years and the market is not liquid in South Australia.

As well as their role as a risk management tool for generators and retailers, contracts underpin investment signals in the NEM.

There has been a downward trend in the volume of contracts traded in recent years (section 6.1.1). But it is difficult to quantify how *liquidity* (the ease of buying and selling) in the contract markets has changed over time. Contract markets are complex and participants' trading positions are commercially sensitive.

There is limited public information available on the contracting arrangements in the NEM. The Australian Securities Exchange (ASX) publishes some information on trading including the price and volumes traded, but not the parties to transactions (because it is an anonymous platform). Information about OTC contract trading is currently only available publicly through the Australian Financial Markets Association (AFMA) voluntary surveys. AFMA aggregates and analyses data submitted to it by some market participant organisations.[27] AFMA has stated most OTC trades would be covered by the survey, but as it is a survey of selected participants it may not include all trades. The AFMA data includes information on volumes traded, but not the prices or parties to those transactions.

We examined the liquidity of contracts traded on the ASX using available public information[28] and found:

- forward contract markets are liquid only out to about two and a half years
- the contract market is not liquid in South Australia compared with other regions.

We assessed liquidity based on changes in the number of open contracts (changes in open interest) in baseload futures on the ASX. Regular changes in open interest show participants can open or close positions easily and indicate a liquid market. Products are listed for trade on the ASX four years before the period of the contract. But participants generally only start trading contracts approximately two and a half years before the trading period. There is regular trade in Queensland, NSW and Victoria and minimal trading in South Australia (figure 3.14). The AEMC cited the lack of liquidity in South Australia as a concern in its 2018 retail competition report.

Contract markets have been closely examined in several other market reviews this year including by the AEMC[29] and the ACCC Retail Electricity Pricing Inquiry.[30] Both addressed the need for greater transparency of outcomes

25 Tasmanian Government Electricity Supply Industry Expert Panel, *An independent review of the Tasmanian electricity supply industry*, March 2012, p. vi.

26 Guy Barnett Tasmanian Minister for Energy, Government gets to work on Tasmania First energy policy, media statement, 23 March 2018.

27 Participants for 2015–16 and 2016–17 were AGL Energy Limited, Alinta Energy, ENGIE, Ergon Energy Queensland Pty Ltd, ERM Power Limited, Hydro Tasmania, InterGen (Australia) Pty Ltd, Macquarie Group Limited, Origin Energy, Snowy Hydro Limited, Stanwell Corporation Limited, Westpac Banking Corporation.

28 The AER's information gathering powers to carry out wholesale market monitoring functions are limited. We must first use publicly available information. (Section 18D(1)(a), National Electricity Law)).

29 AEMC, *Retail energy competition review—final report*, June 2018.

30 ACCC, *Retail electricity pricing inquiry—final report*, June 2018.

in the contracts market (chapter 7). Both also documented particular concern with the contract market in South Australia. The AEMC found limited access to competitively priced risk management products creates barriers to entry and expansion in South Australia.[31]

### Box 3.5 Contract markets

Given spot prices can rise as high as $14 500 per megawatt hour (MWh) or fall as low as –$1000 per MWh, most market participants manage at least some of their exposure to price risk by entering into hedge contracts (also called forward contracts or derivatives). Hedge contracts lock in firm prices for electricity they intend to buy or sell in the future. Alongside generators and retailers, participants in electricity contract markets include financial intermediaries and speculators. Contract prices tend to reflect market expectations of future wholesale prices for the period covered by the relevant product.

Wholesale market participants trade hedge products in two distinct ways:

- *over the counter (OTC)*—this involves direct contracting between counterparties often assisted by a broker
- *exchange traded*—electricity futures products are traded on the Australian Securities Exchange (ASX).

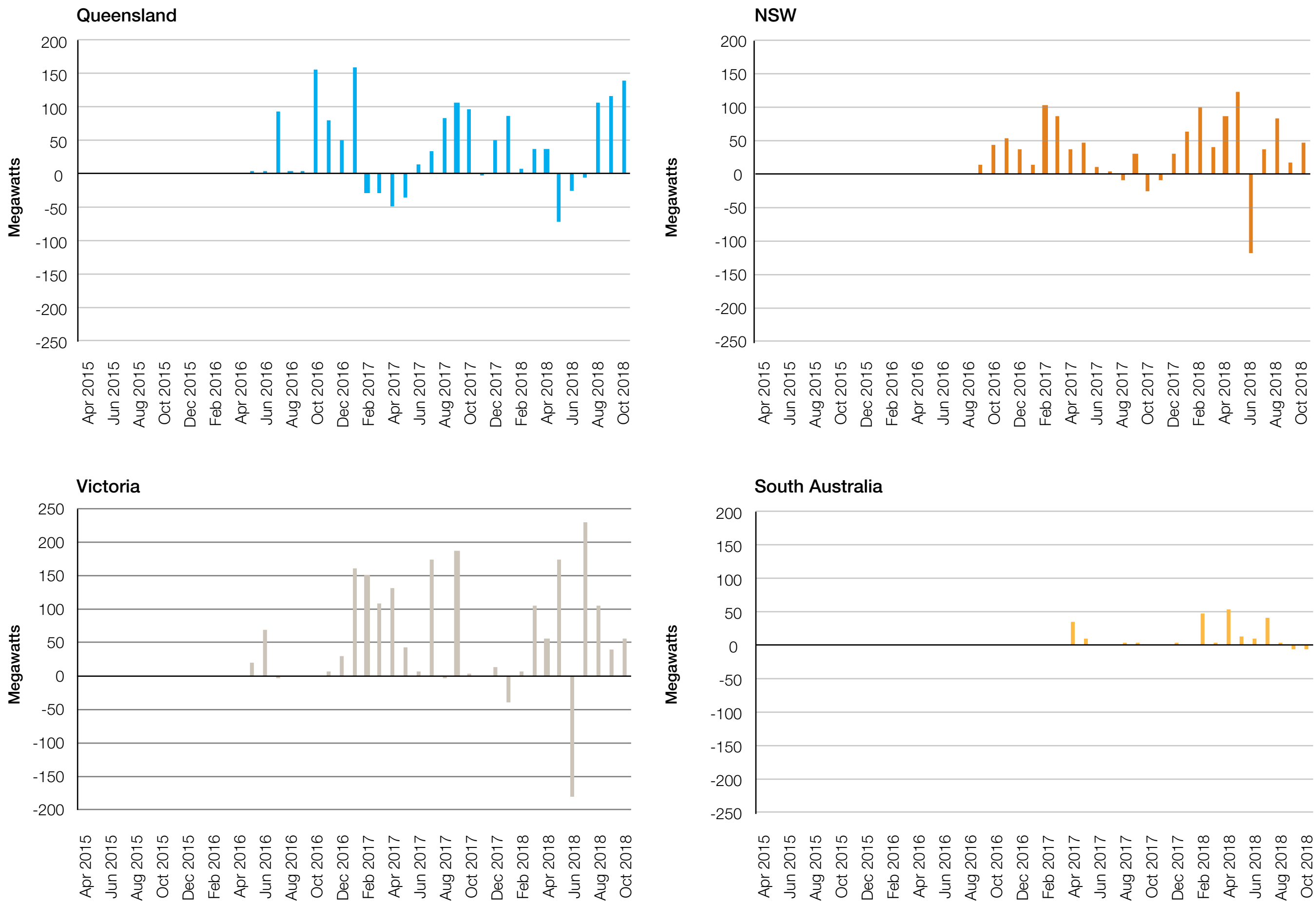
There are a range of derivatives products. The ASX products are standardised to promote trading, while OTC products are more flexible and can be sculpted to suit the requirements of the counterparties.There are a number of products typically traded:

- *Futures* are a type of ASX contract allowing a party to lock in a fixed price to buy or sell a given quantity of electricity over a specified time in the future. Each contract relates to a nominated time of day in a particular region. Available products include quarterly base contracts (covering all trading intervals) and peak contracts (covering specified times of generally high energy demand). Futures can also be traded as calendar or financial year strips covering all four quarters of a year. In OTC markets, futures are known as swaps or contracts for difference.
- *Options* are a type of contract giving the holder the right—without obligation—to enter a contract at an agreed price, volume and term in the future. The buyer pays a premium for this added flexibility.
- *Caps* are contracts setting an upper limit on the price a holder will pay for electricity in the future, while floors are contracts setting a lower price limit. Caps can be traded either as futures or options.

As well as being a risk management tool for generators and retailers, contract markets underpin investment signals in the national electricity market.

31 AEMC, *Retail energy competition review—final report*, June 2018, p. 37.

**Figure 3.14 Monthly change in open interest for base futures, Q1 2019**




Note: Large spikes in May 2018 are due to contracts being converted to other types of contracts.

Source: ASX.

## 3.6 There is limited market based demand response in the NEM, but its influence in the market may grow

Demand response is a form of demand side participation in the NEM. In the context of the wholesale market demand response can help participants manage their market positions, as an alternative to new capacity, and to manage prices and supply in tight market conditions. It can also participate in ancillary services markets to maintain grid frequency within its operational limits. Demand response can potentially limit the potential for generators to exploit market power, but currently provides little competitive pressure in the NEM.

Our enquiries with market participants indicated an interest in developing demand side participation and the potential role it could play in the NEM. However, they also noted a limited uptake of demand side products, which if anything had reduced recently. For summer 2017–18, AEMO estimated there was only 207 MW of expected demand response to different wholesale price levels.[32] In some cases, participants suggested the reliability and emergency reserve trader (RERT) mechanism is crowding out demand for these products (section 6.1.4). Less spot price volatility has also reduced the need for demand response products.

Recent market investigations such as the Finkel review[33] and the ACCC Retail Electricity Pricing Inquiry[34] found the NEM lacked the mechanisms and sufficient incentives for encouraging the growth of demand response. The AEMC considered wholesale demand response as part of its Reliability Frameworks Review[35] and it is currently the subject of several rule changes (chapter 7).

32 AEMO, *Demand side participation*, accessed 7 September 2018. In the event a Lack of Reserve notice was issued, this value increased to 278 MW. These values don't include demand response procured by AEMO through the RERT process.

33 Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*, June 2017.

34 ACCC, *Retail electricity pricing inquiry—final report*, June 2018.

35 AEMC, *Reliability frameworks review—final report*, July 2018.

# 4. Do participants exercise market power?

## Key points

- While participants do exercise market power from time to time, often this is only transient (sections 4.2.1 and 4.3). However, there are some market outcomes that we are monitoring closely to see whether they are sustained and undermining effective competition.
- Electricity dispatch price offers across the national electricity market (NEM) increased over the past five years. Contributing factors include rising fuel costs, changing generation mix and physical issues. However, trends in Queensland and New South Wales (NSW) cannot be explained by these factors alone, particularly an increase in fuel costs. We will continue to monitor behaviour in both these regions closely in 2019.
- We analysed the reason for short term price spikes including rebidding, withholding and ramp rates. Participants appeared to have exercised market power at times in the past five years, but it has not been sustained. Opportunistic rebidding by some Queensland generators caused periods of spot price volatility between 2013 and 2016, but this behaviour has declined significantly more recently.
- In South Australia, frequency control ancillary services (FCAS) costs increased significantly over the past five years. This result reflects participants exercising their market power in response to increased local regulation requirements. However, these issues are unlikely to persist, because new entrants have joined the market and the requirement for additional local services has been removed.

A participant may have an ability, and even an incentive, to exercise market power. But that does not mean they will do so in a way that harms effective competition.

Participants can exercise market power in several ways (box 4.1). We analysed participant conduct over the past five years to determine whether these behaviours were a sustained feature in the market and whether they contributed significantly to recent price increases or market volatility. We assessed longer term trends in participants' bidding conduct. We also considered within day conduct–how participants responded to certain circumstances, such as when a unit unexpectedly trips or a demand forecast is high on a hot day.

The factors we must have regard to under the National Electricity Law suggest we should consider the extent to which market power is sustained (section 1.2.1). That is, a few isolated instances of transient market power alone are not sufficient to conclude competition in the NEM is not effective. For this reason, we focused on areas where behaviour is more likely to have significantly increased average prices and considered whether it is likely to be sustained.

This chapter explores the likelihood that participants exercised market power to increase prices:

- Section 4.1 highlights longer term trends in participants' energy offers and the likelihood that changes are due to an exercise of market power.
- Section 4.2 considers whether participants engaged in short term strategies to spike energy spot prices.
- Section 4.3 highlights issues in the South Australian FCAS markets.

### Box 4.1 How do participants exercise market power in the NEM?

A range of conduct is typically associated with the exercise of market power in energy markets. Participants can use strategies within a trading day to spike prices or engage in longer term strategies, including:

- reducing the amount of capacity offered to the market or not offering capacity at all. This physical withholding of capacity can create an artificial shortage, pushing up prices and leading to higher revenues for the participant's remaining generation fleet. This is referred to as physical withholding.
- raising the price of output above marginal costs. For example by shifting capacity to extremely high prices. This is referred to as economic withholding.
- rebidding capacity from low to high prices close to dispatch. This type of behaviour can limit the ability of other participants to respond to price signals competitively.
- minimising the rate at which a unit can be ramped down (which may differ from its technical capability) at times of high prices to continue generating, in so doing displacing lower priced generation.

Participants may also reprice capacity over a longer period to slightly higher prices, to drive average prices higher (without necessarily rebidding within the day).

Some behaviours may appear to be a potential exercise of market power, but are in fact an efficient response to changing market conditions or a plant's technical requirements. Rebidding, for example, can promote efficient market outcomes and can be beneficial for competition (box 4.3).

## 4.1 Participant offers in all regions have increased, but in NSW and Queensland, offers may be above costs

Over the past five years, many participants have increased the prices at which they are willing to supply electricity, with less capacity offered below $50 per megawatt hour (MWh) and more between $50 and $150 per MWh. The result is higher average prices. Repricing capacity among NSW black coal generators in particular affected prices significantly across the NEM, and are therefore a focus of our review.

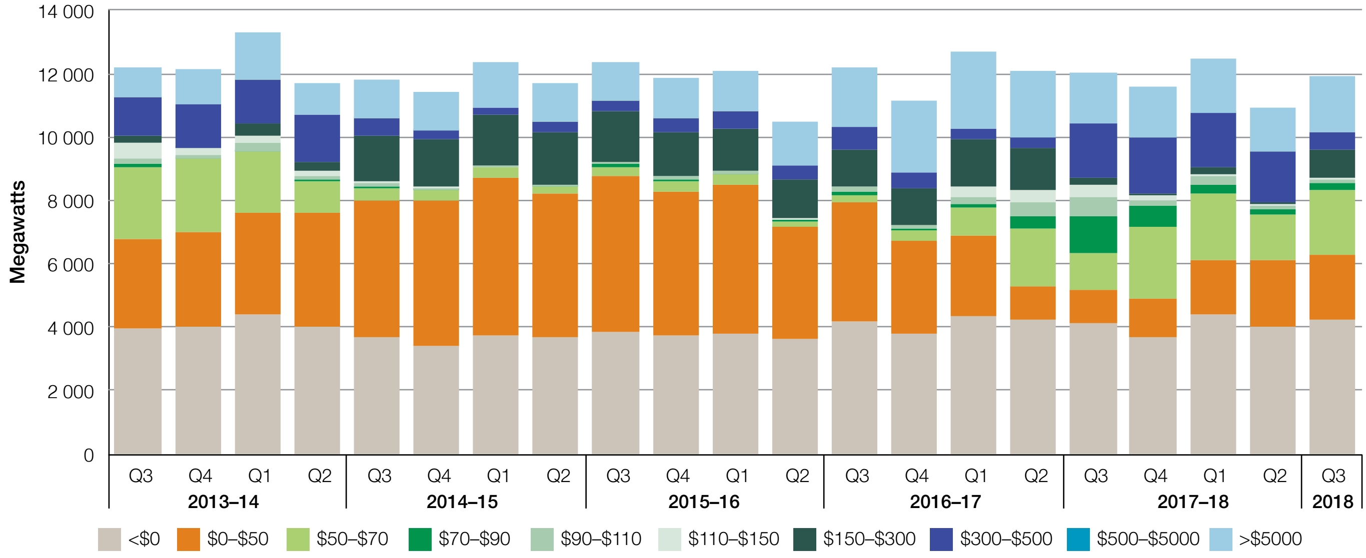
The dispatch price for each 5 minute dispatch interval is set by the marginal generator (the last generator dispatched to provide the last megawatt needed to meet demand). Every 30 minutes, the dispatch prices are averaged to determine the spot price. All participants dispatched will receive the spot price regardless of the price of their dispatch offers (box 2.1 has more information on how prices are set in the NEM). Black coal generators in NSW have a significant role in setting the price in all mainland NEM regions, setting the price between 28–54 per cent of the time in 2017–18.

The drivers of changes in offers vary between regions. Increased costs are one reason for the change in offers. The cost of coal and gas, the key fuel inputs for electricity generation, have increased over the past five years (section 2.3). But these increases alone may not account for all of the increase in offer prices from all participants, particularly among black coal generators in NSW and Queensland.

### 4.1.1 In NSW increased fuel costs and fuel supply issues drove offers higher, but may not explain all of the increase

Since 2015, participants in NSW have reduced the amount of capacity offered at less than $50 per MWh (figure 4.1). From 2016, capacity priced between $50 and $150 per MWh increased, while capacity priced between $150 and $300 per MWh was replaced by capacity priced between $300 and $500 per MWh. In 2018 this trend reversed, with more capacity priced between $0 and $50 per MWh. And, in quarter three capacity priced between $300 and $500 per MWh has been replaced by capacity priced between $150 and $300 per MWh. Black coal, gas and hydroelectricity participants all increased their offers.

**Figure 4.1 NSW offered capacity, by price thresholds**




Source: AEMO data, AER analysis.

The international spot price for thermal coal has increased considerably in recent years (section 2.3). However, most generators do not pay this price for all their coal supply. Generators typically source coal under a range of short and long term contracts. Generally, prices negotiated under short term contracts are likely to align more closely with the prevailing international coal spot price. Generators may also be exposed to rising coal prices under long term contracts, if prices under those contracts are benchmarked against international coal prices or if contract renegotiations coincide with rising coal prices.

Our earlier review into the NSW electricity market[36] found NSW generators' coal costs were increasing, particularly under short term contracts. In June 2018 the Australian Competition and Consumer Commission (ACCC) reported updated data on the weighted average fuel costs of all NSW and Queensland generators (figure 4.5). NSW generators coal costs increased 73 per cent between 2015 and quarter one 2018.[37] But, both our earlier review and the ACCC's review confirmed the increased coal costs did not fully account for the increase in NSW coal participants' offers.

As noted above, the dispatch price in the NEM is set by the marginal unit, that is the last one AEMO calls on to balance supply and demand. Figure 4.2 shows a monthly average of NSW dispatch prices when these prices are set by a marginal NSW coal unit. It compares these prices against an international reference price for spot thermal coal in Newcastle (converted to $AUD per MWh).[38] In an environment of rising coal prices, the international spot price can be used as a proxy for a generator's *maximum* marginal cost of coal.[39] However, this price is unlikely to be the marginal cost of coal for all generators all of the time.

From late 2016 through to 2017, the price at which coal generators were setting the price diverged quite significantly from the international costs of coal. Our earlier review highlighted issues that could have contributed to this divergence. In addition to higher fuel costs, generators were concerned about managing fuel stockpiles with all NSW black coal generators experiencing problems with coal supply. Some black coal generators sought to limit dispatch by offering electricity at higher prices, to ensure sufficient coal would be available during the peak 2017–18 summer period.

The ACCC found the overall divergence between NSW black coal offer prices and their fuel costs was due to a lack of competitive constraint on NSW black coal generators, partly because of the closure of Hazelwood power station in Victoria.[40] We also reported we were concerned NSW coal generators appeared to be facing less competitive constraint and this may have contributed to their higher priced offers. [41]

36 AER, Electricity wholesale performance monitoring—NSW electricity market advice, December 2017.

37 ACCC, *Retail electricity pricing inquiry—final report*, July 2018, p. 67.

38 The globalCOAL Newcastle coal price index is a reference price for spot thermal coal at Newcastle Port in NSW. The globalCOAL methodology is available at www.globalcoal.com.

39 This analysis does not account for a generator's other variable costs.

40 ACCC, *Retail electricity pricing inquiry—final report*, July 2018, p. 69.

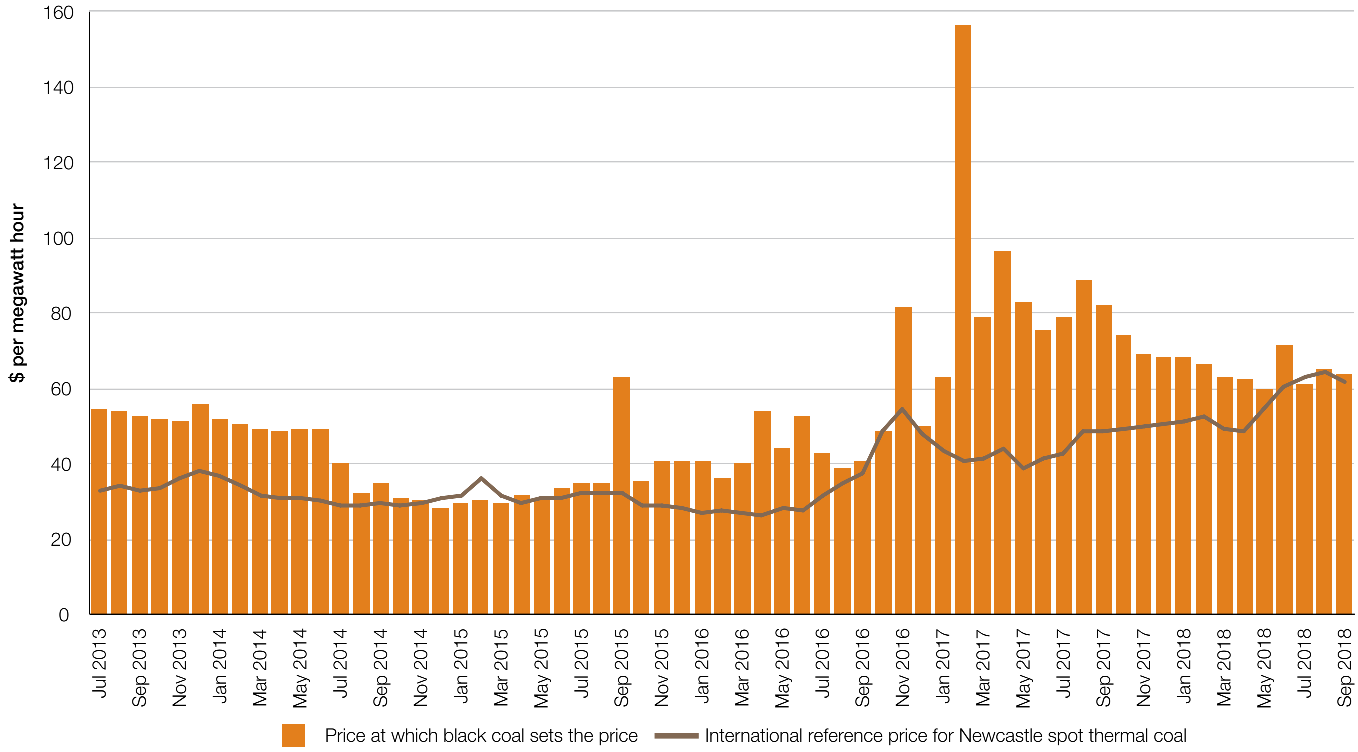
41 AER, Electricity wholesale performance monitoring—NSW electricity market advice, December 2017, p. 21.

The average price at which black coal generators set price has fallen from its peak in late 2017, but still remains higher than historical levels. During this review, NSW black coal generators confirmed they have recovered from the stockpile and supply concerns that existed in 2017. The recovery of stockpiles coincided with NSW black coal participants offering more capacity at slightly lower prices. However, international coal prices continue to increase the cost of coal for generators where cheaper non-price linked legacy contracts are not in place. We will continue to monitor the offers of NSW coal generators and may request additional information on their costs in 2019 if we remain concerned.

We also considered whether there was evidence that NSW black coal participants were 'shadow pricing' gas participants' offers. Shadow pricing occurs when pricing of one commodity is just below the pricing of another commodity, irrespective of the cost of the commodity.

We did not identify a strong correlation between price set by NSW black coal and price set by gas (figure 4.3). Carbon pricing was in place from 2012–13 and 2013–14, which made the price set by coal generation roughly the same as gas, as intended. When carbon pricing was removed, the price set by coal and gas generation diverged. In many instances, black coal did not shadow the increase in the price at which gas generators set the price– for example, in July 2016 and July 2018. But at other times the price set by black coal was just below that of gas, particularly during the period of coal supply concerns in 2017. Since coal supply concerns eased, this gap increased to similar levels as in 2015 (at around $20–$30 per MWh). This outcome suggests no long term shadowing of gas prices by black coal.

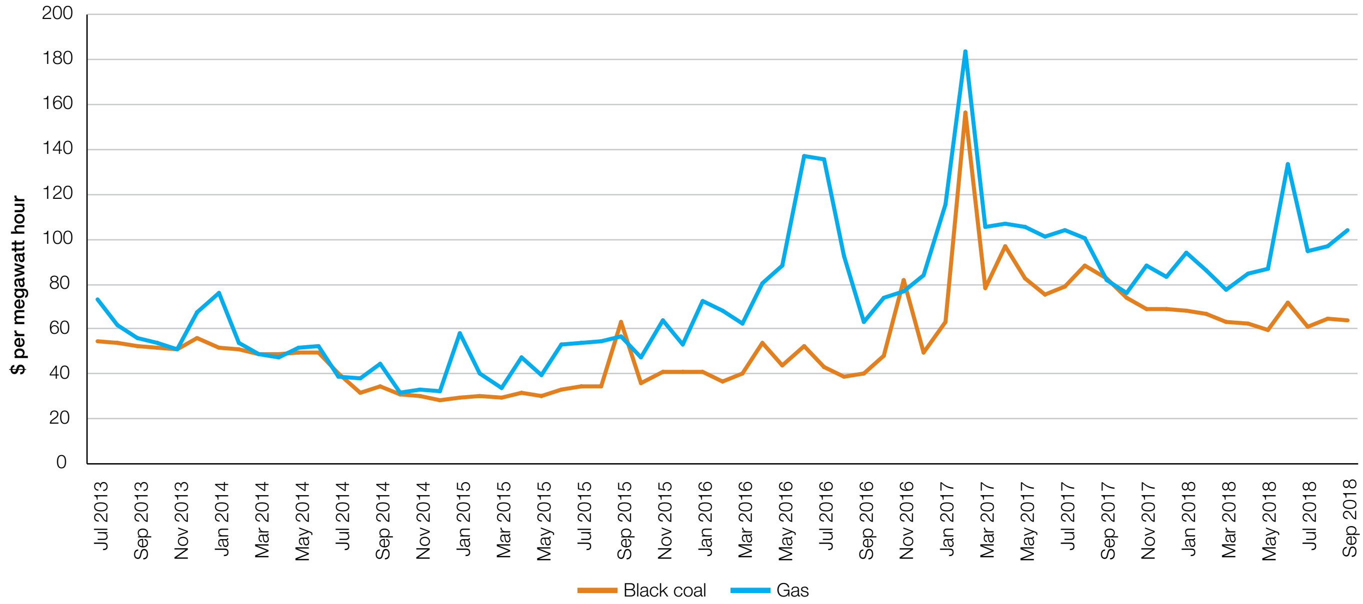
**Figure 4.2 International reference price for Newcastle spot thermal coal and the average monthly price when a NSW black coal unit is marginal and sets the price**




Note: Cost of coal derived from Newcastle USD/tonne converted to AUD per MWh with RBA exchange rate, and average heat rate for coal.

Sources: AEMO, globalCOAL data, AER analysis.

Figure 4.3 Average monthly price when the fuel type is setting price




Sources: AEMO data, AER analysis.

### 4.1.2 In Queensland offers have increased in line with NSW, even though their costs are lower

In Queensland offer strategies have changed since 2013, resulting in less price volatility but higher average prices (figure 4.4). Since 2013 capacity offered below $0 per MWh has increased, while capacity priced between $0 and $50 per MWh declined. Capacity offered between $50 and $300 per MWh also fell between 2014 and 2017 (the green sections in figure 4.4). These factors, combined with late rebidding, saw volatile prices in Queensland during this period, with prices jumping from below $50 per MWh to above $300 per MWh. Recently, capacity offered between $50 and $300 per MWh increased.

Rebidding was an issue in Queensland in 2014 and 2015, but it was largely resolved by a rule change (section 4.2.1) and more recently by government intervention. In mid-2017 the Queensland Government directed one of its government owned generation businesses to bring down the spot price (section 3.4.2).

The offer strategy in Queensland is similar to that of NSW since mid-2016 (figure 4.1 shows NSW offers). Both states have a similar combination of generation types; black coal is the major fuel source. Black coal typically competes in between the lower fuel cost renewable and brown coal generation and the higher fuel cost gas generation to set prices in the NEM.

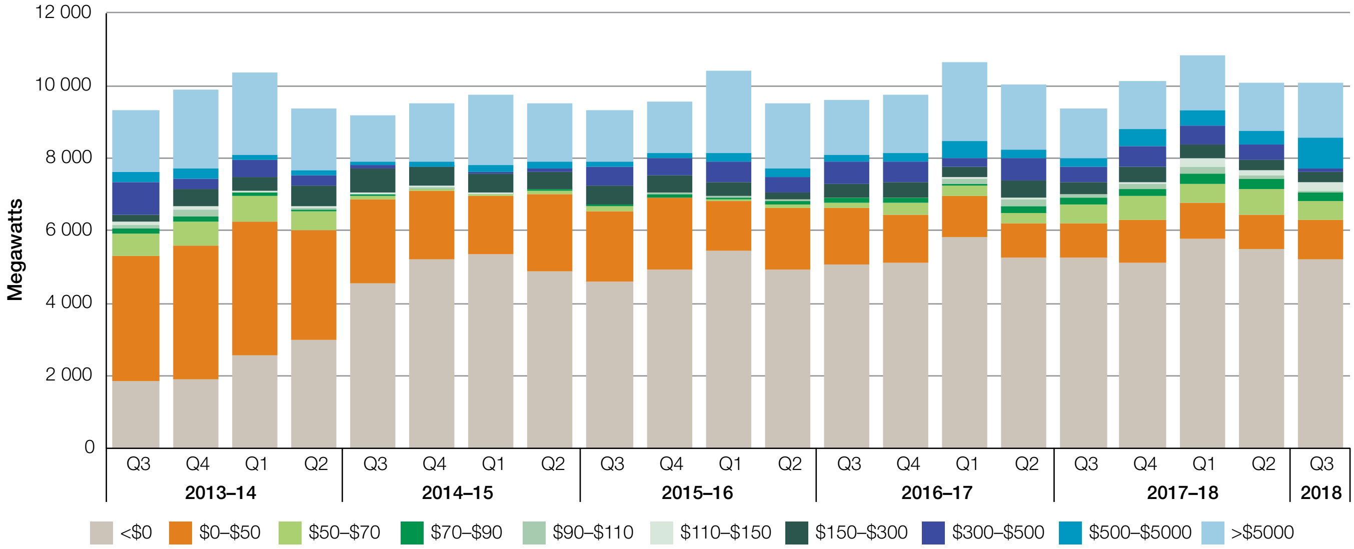
However, Queensland generators' black coal comes from different sources to NSW generators' black coal, so it will not necessarily have the same costs or be subject to the same supply issues. The ACCC found between 2015 and quarter one 2018, the cost of black coal in NSW increased by 73 per cent (from $40 to $69 per tonne). Yet in the same period, the cost of black coal in Queensland declined by 5 per cent (from $36 to $34 per tonne).[42] Nevertheless Queensland black coal participant's offers changed, with capacity priced between $0 and $50 per MWh decreasing and capacity priced between $50 and $150 per MWh increasing.

This suggests that when NSW experienced coal supply issues and NSW coal participants offered capacity at higher prices (section 2.2–2.3), Queensland participants also repriced capacity. The price at which both NSW and Queensland black coal generation set price were very similar (figure 4.6), despite the cost differences (figure 4.5). This result may indicate Queensland participants were shadow pricing to maximise profits by offering at or just below their nearest competitor, NSW black coal. It may also be that Queensland black coal generators are exposed at the margins to international coal prices. This could affect their offers and the price at which they set coal.[43] We will continue to monitor Queensland coal generators' offers and may request additional information on their costs in 2019 if we remain concerned.

42 ACCC, *Retail electricity pricing inquiry—final report*, July 2018, p. 67.

43 For example, we understand Stanwell have agreements for the Stanwell power station, which include an options to receive additional coal, which could be used for export (Stanwell, Annual report 2015-16, 2016). This may increase the opportunity cost of coal for electricity generation.

## Figure 4.4 Queensland offered capacity by price thresholds



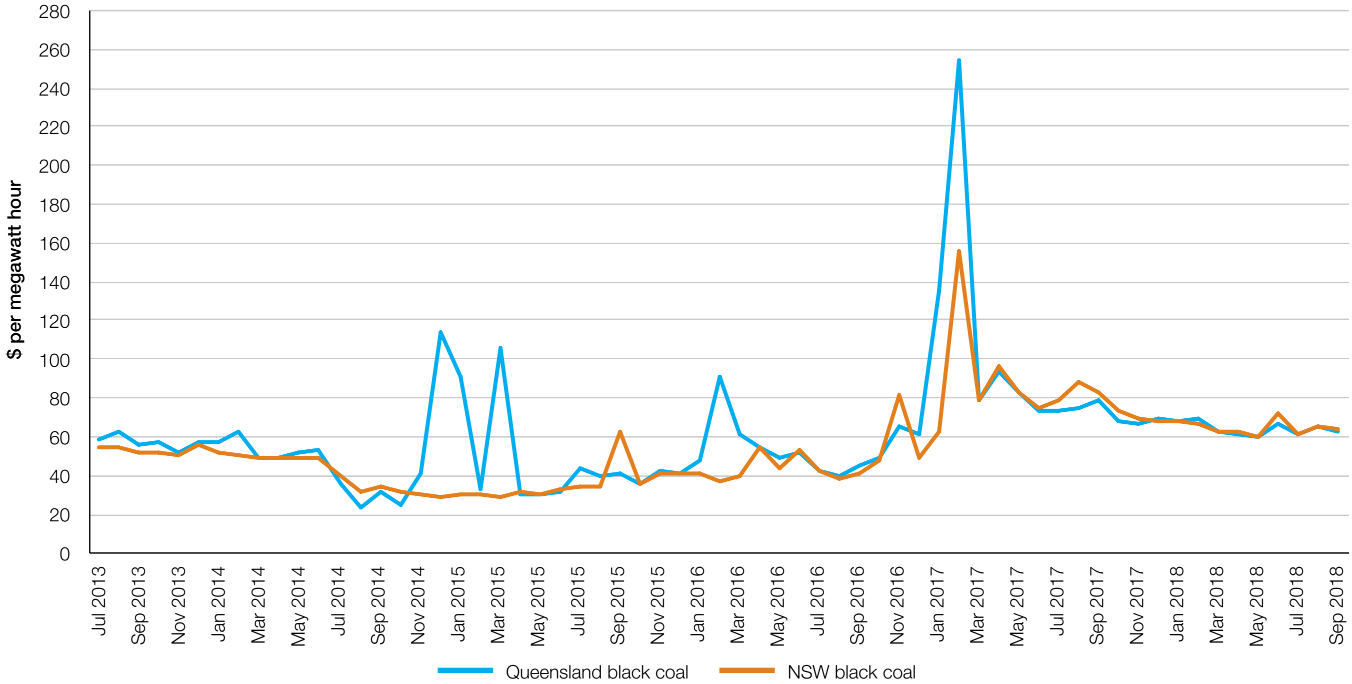

Source: AEMO data, AER analysis.

## Figure 4.5 Annual weighted average black coal generator's fuel costs ($ per tonne)

| | 2015 | 2016 | 2017 | Q1 2018 | Change from 2015 to Q1 2018 |
|---|---|---|---|---|---|
| NSW | 40 | 45 | 58 | 69 | 73% |
| Queensland | 36 | 36 | 35 | 34 | -5% |

Source: ACCC *Retail electricity pricing inquiry—final report*, July 2018, p. 67.

## Figure 4.6 Average monthly price when Queensland and NSW black coal generators are setting the price




Source: AEMO data, AER analysis.

### 4.1.3 Recent price rises in Victoria are attributable to less low cost capacity and higher priced imports from NSW

Price increases in Victoria were due to the removal of low fuel cost capacity after the Hazelwood power station closed, and the increased reliance on higher cost generation from NSW. Offers from remaining generators were relatively stable following the closure of Hazelwood, but prices were higher.

The station's closure in March 2017 reduced Victoria's available capacity by 1600 megawatts (MW) and, from quarter two 2017, capacity offered at prices below $50 per MWh declined. Since then, capacity offered between $70 and $300 per MWh has increased (figure 4.7). Victoria also imports more energy from NSW. Our Hazelwood report provides further information and analysis about the closure and its impacts.[44]

### 4.1.4 In South Australia changes in offers are mainly affected by wind availability and gas prices

Changes in average offers in South Australia over the past five years reflect a changing generation mix and higher gas costs. South Australia's generation mix leaves it susceptible to volatile price outcomes (figure 4.8).

Capacity priced between $0 and $50 per MWh has virtually disappeared since Northern power station shut down in quarter one 2016. South Australia's market is now comprised of a mix of low priced renewable participants, storage and much higher priced gas generation.

Wind generation is generally offered into the market at prices below $0 per MWh and generators receive renewable energy certificates for every megawatt produced. Gas generation is offered in at higher prices because fuel cost is higher (section 2.3). The result is much capacity priced at less than $0 per MWh, and little capacity priced between $0 and $70 per MWh.

Because South Australia has a high penetration of wind, changes in offers are related to the level of wind in the quarter, rather than a change in participant behaviour. Quarter three 2018 was much windier than quarter two, increasing offers below $0 per MWh, for example (figure 4.8).

Since Hazelwood power station closed, South Australia can no longer import cheap energy from Victoria; energy now flows from NSW. So South Australian prices are increasingly set by black coal from NSW, local gas generation and gas from Victoria, all of which now set prices at higher levels than Hazelwood.

### 4.1.5 Changes in prices in Tasmania in recent years were largely driven by physical issues

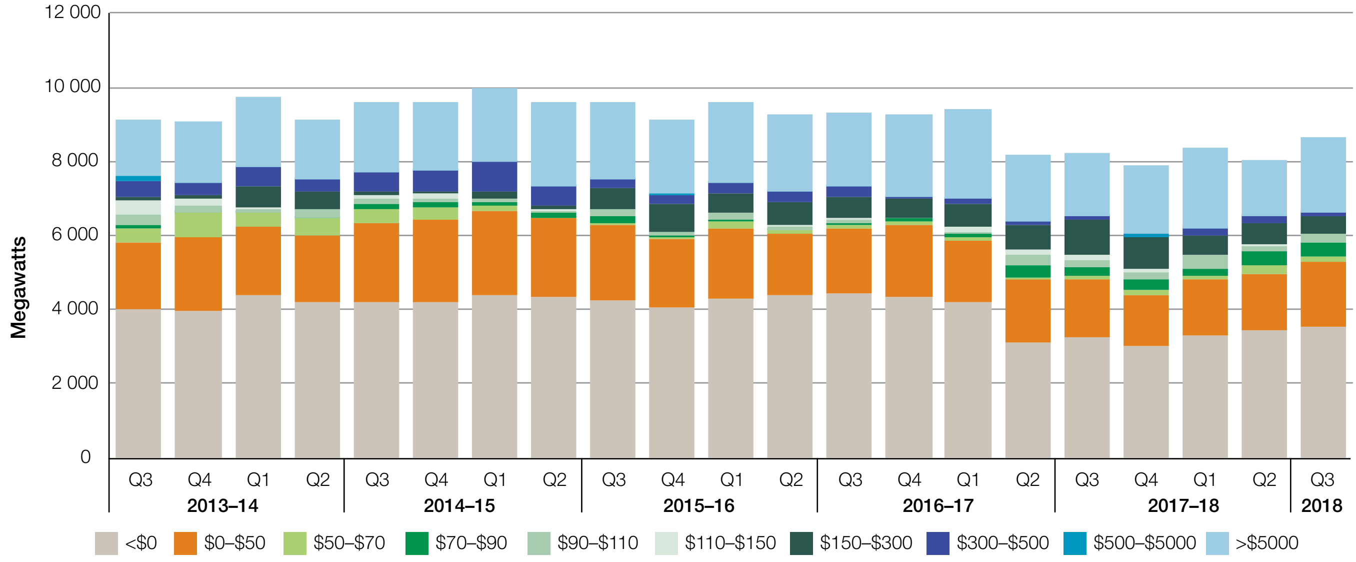
Hydro Tasmania is the only participant in Tasmania and most of its portfolio consists of hydroelectric generation. Offers can change significantly depending on the value of water, which in turn can be affected by factors like dam levels, forecast rainfalls and interconnector capability. The prices at which Hydro Tasmania may offer wholesale contracts are regulated, which may limit Hydro Tasmania's incentives to exercise market power (section 3.4.2).

Tasmania is also connected to the mainland by one interconnector, Basslink. An unexpected outage in December 2015 meant Tasmania had to supply its own generation. Figure 4.9 shows how this affected offers, with a reduction in capacity priced below $50 per MWh and an increase in capacity priced between $50 and $300 per MWh. Basslink came back on line in late May 2016 but since then has experienced further outages that affected offers.

Quarter three 2018 has seen the most capacity offered below zero in the past five years, and capacity between $0 and $50 per MWh increased.

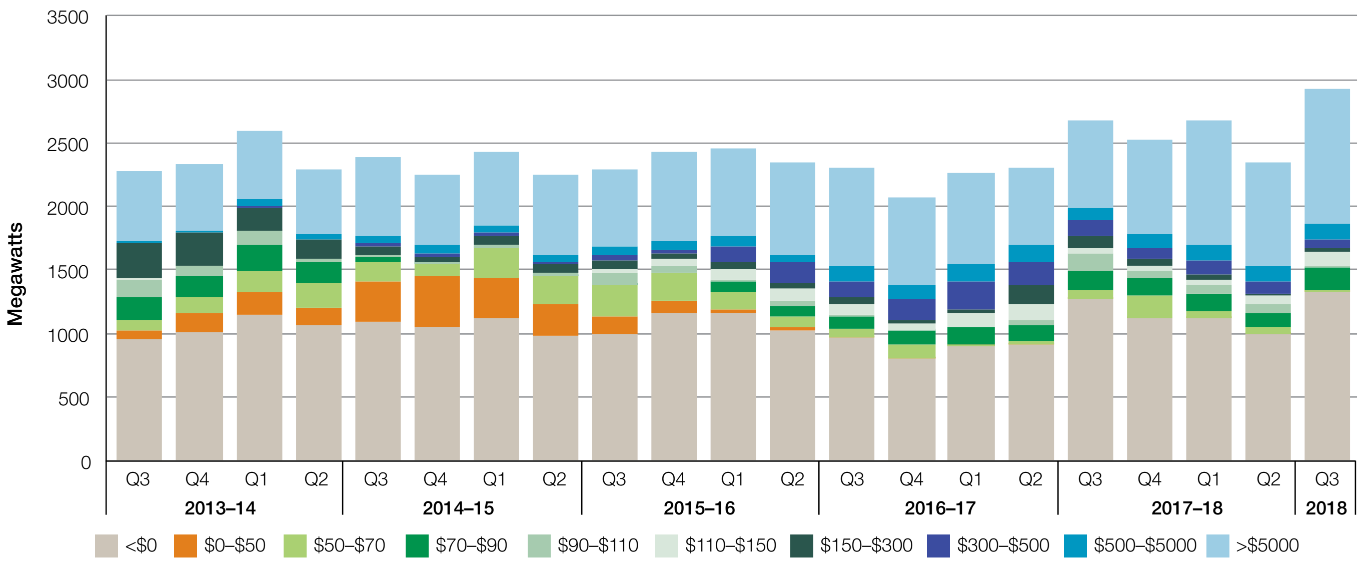
44 AER, *Electricity wholesale performance monitoring—Hazelwood advice*, March 2018.

Figure 4.7 Victoria offered capacity by price thresholds



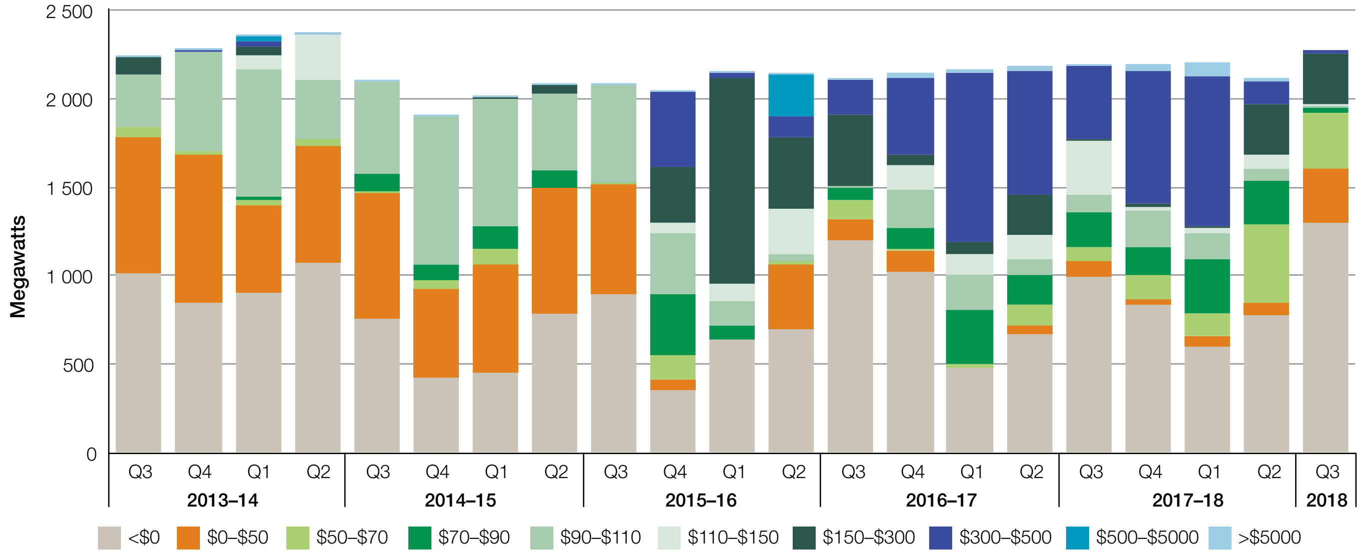

Source: AEMO data, AER analysis.

Figure 4.8 South Australia offered capacity by price thresholds




Source: AEMO data, AER analysis.

Figure 4.9 Tasmania offered capacity by price thresholds




Source: AEMO data, AER analysis.

## 4.2 While there have been issues in the past, behaviour that drives price spikes has reduced in recent years

Price spikes have not been a significant driver of recent price increases, with the number of price spikes falling substantially since mid-2017 (section 2.2.3). There have been fewer price spikes in Queensland and South Australia in particular.

In the past five years, four reasons accounted for 75 per cent of breaches: generator rebidding, generator availability, inaccurate demand forecasts and generator ramp rates (box 4.2).

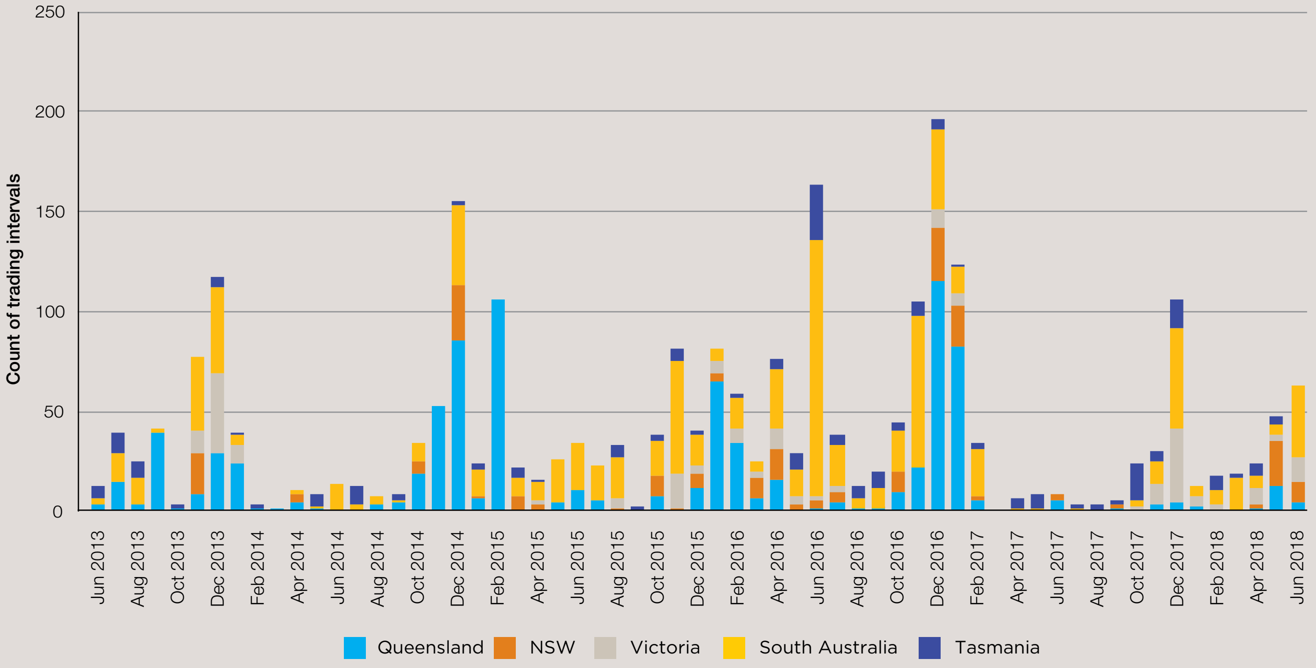
### Box 4.2 Factors contributing to price spikes

The National Electricity Rules (the Rules) require us to analyse why prices vary from forecast and publish this information weekly. We do in-depth analysis when the spot price exceeds the reporting thresholds (when spot prices are above $250 per megawatt hour (MWh) and are more than three times the weekly volume weighted average (VWA) price and we assign reasons why the price differed from forecast. We track 13 reasons that contribute to spot prices varying from forecast and use these in the following analysis. Also under the Rules, if the spot price exceeds $5000 per MWh, we must write a report explaining why it occurred and must include whether rebidding contributed.

Not captured in the weekly analysis is when forecast high prices eventuate. When the Basslink interconnector was unavailable in 2016, prices in Tasmania were forecast to be high and high prices eventuated, for example. These are not considered short term influences in our analysis.

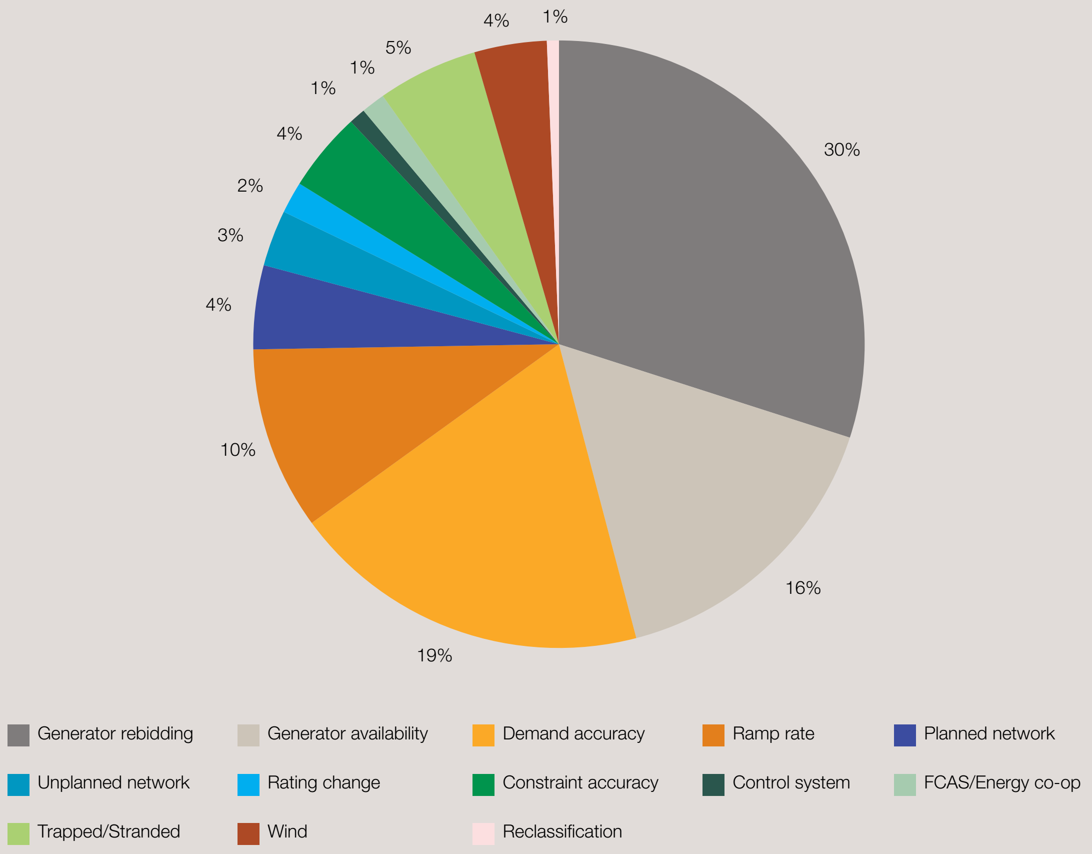
Figure 4.10 highlights how often our reporting threshold was breached in each region. Until mid-2017, most occurrences were in Queensland and South Australia. Since then, breaches have reduced significantly.

**Figure 4.10 Count of spot price above the AER weekly reporting threshold (>$250 per MWh and >3 times the weekly VWA price) by region**




Source: AER

**Figure 4.11 Reasons contributing to the price exceeding the threshold**




Source: AER.

### 4.2.1 Rebidding in Queensland was an issue in the past, but has reduced in recent years

Rebidding is a mechanism that allows participants to change their offers. It can promote efficiency in dispatch, but may also compromise competitive outcomes (box 4.3).

In Queensland, participants have previously taken advantage of the concentrated market and rebid large volumes of capacity from low to very high prices late in the trading interval, spiking prices. The strategy was typically used on days of high temperatures and high demand, and occurred most often during summer between 2013 and 2016.[45] Rebidding late in a trading interval gives other participants little time to provide a competitive response, resulting in a high price. This can undermine the effectiveness of competition in the market. Since the Queensland Government direction to Stanwell in July 2017 (section 3.4.2), price volatility due to generator rebidding has declined and there have been very few high prices despite record demand (figure 4.12).

A shift of rebids from 45 minutes to 10 minutes before the end of the trading interval, for example, severely limits opportunities for a competitive response. The Australian Energy Market Commission (AEMC) changed the rules regarding rebidding in 2016 to deter this behaviour and provide more efficient prices. The rule change defined a 'late rebidding period' as 15 minutes before a trading interval starts and the period of the trading interval itself (that is 45 minutes before the end of the trading interval). If a rebid is made within this late rebidding period, then the participant must keep contemporaneous records, which we can request to ensure the rebid was not false or misleading.

Analysis of the timing of late rebids over the past five years by Queensland participants each month shows rebids made 10 minutes before dispatch were at their highest in summer 2014 (figure 4.13). Late rebidding declined after the AEMC began the rule change process in 2014.

In other regions, the number of late rebids did not change materially (appendix A). In 2018 the AEMC found late or other rebidding was not a significant factor driving volatility in the NEM.[46]

#### Box 4.3 Rebidding in the NEM

The efficient and secure operation of the national electricity market (NEM) depends on instantaneously matching electricity supply and demand. At the same time, the NEM is a dynamic market, where participants can adjust their offers through rebidding to reflect changing events such as technical limitations of units, or in response to changing market conditions.

Participants offer their availability to the market in up to 10 price bands. The price of these bands cannot change during a trading day but the amount of capacity in each band can. Offers can be made from months in advance up to just before dispatch. Other parameters can also be rebid, such as ramp rates. Annually, participants submit millions of rebids.

In the short term, rebidding promotes efficient dispatch because it allows the market to respond dynamically to changing conditions and better information. Rebidding allows participants to respond to changes in price, market conditions, or bidding strategies of competitors at short notice and in turn create efficient price outcomes. A participant may respond to a higher than expected demand forecast, for example, by offering additional capacity to the market.

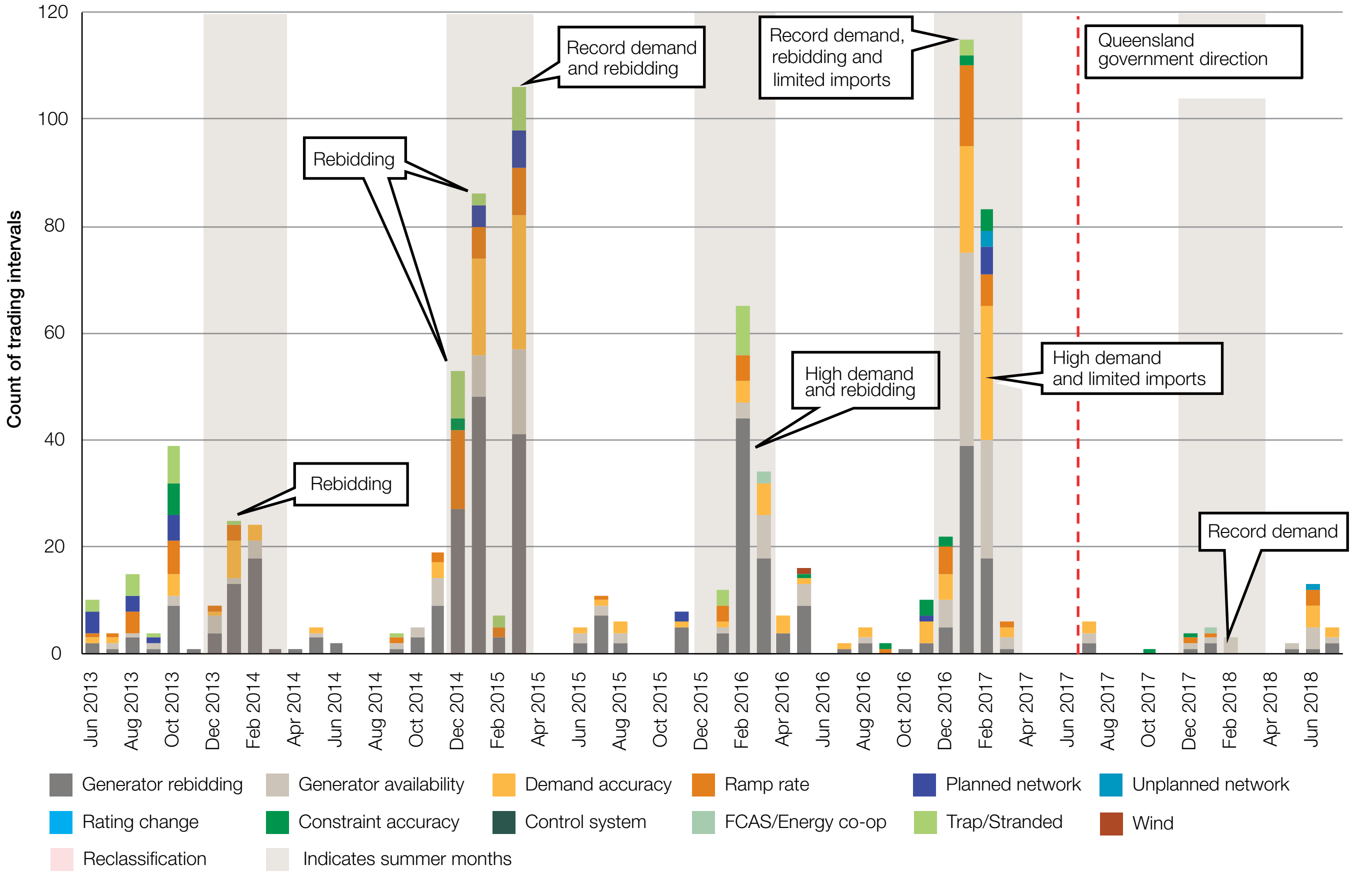
Over the long term, rebidding also indirectly supports efficient investment decisions. Efficient wholesale prices provide the best signal for investment, both in terms of the quantity and type of generation capacity, and the demand response needed over time.

But, some rebidding can be detrimental to competition and efficiency. Rebidding just before dispatch that is not in response to a genuine change in market conditions, for example, can limit the ability of other participants to provide a competitive response and therefore lead to inefficient outcomes. The National Electricity Rules prohibit participants from making false or misleading offers.

45 AER, *State of the energy market 2015*, December 2015.

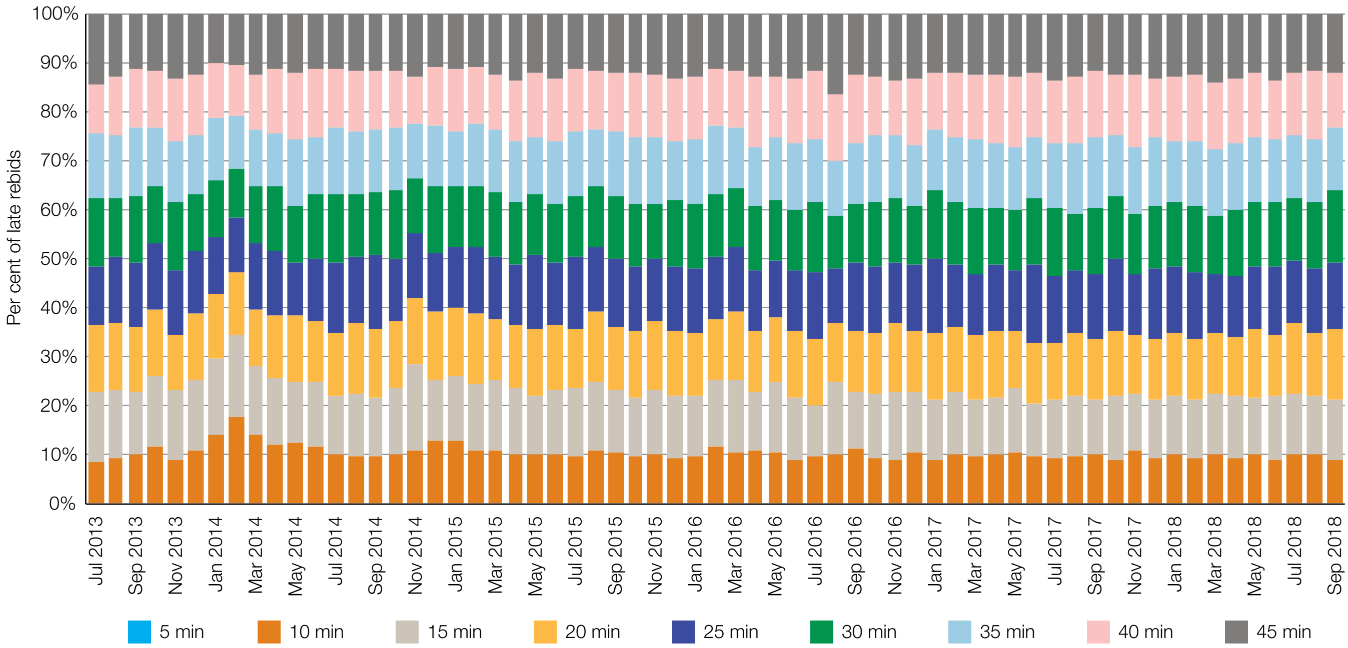
46 AEMC, Gaming in rebidding assessment (Grattan Response), 2018.

## Figure 4.12 Queensland high price events and drivers




Source: AER.

## Figure 4.13 Timing of rebids in the late rebidding period in Queensland




Source: AEMO data, AER analysis.

### 4.2.2 Technical issues explain price spikes caused by generator availability

Generator availability contributed to 16 per cent of the high prices over the past five years (box 4.2). These issues related mainly to technical reasons like unplanned outages and adjustments in response to weather conditions, rather than an attempt to exercise market power.

However, deliberate withholding of capacity (physical withholding) can create artificial shortages and spike prices that compromise competitive and efficient dispatch. The circumstances in which physical withholding is likely to be a profitable strategy are limited, because participants are paid only for electricity they generate.

Over the past five years, when prices spiked due to generator availability, in most circumstances legitimate reasons (outages) led to participants becoming unavailable. Analysis of reasons for physical withholding is in appendix A.

### 4.2.3 Bidding ramp rates below technical capability is likely contributing to price spikes

Over the past five years, ramp rates contributed to 10 per cent of the analysed high prices. Ramp rates are specified by participants as a component of the offers they make to the market and determine how quickly a generator can be ramped up or down by the Australian Energy Market Operator (AEMO) every 5 minutes.

It is possible that, at times, participants use ramp rates to achieve commercial outcomes that can lead to inefficiencies in the wholesale market. The lower the ramp rate is, the slower it can take AEMO to dispatch a unit to another level. A low ramp up rate might mean a generator that has low priced capacity could take longer than necessary to be fully dispatched and in that time more expensive capacity was dispatched in its place. A low ramp down rate might mean a generator that has capacity priced high and is being dispatched would take longer than necessary to have their dispatch reduced and in that time lower priced capacity is not being dispatched.

We raised concerns in 2013 that generators were offering or rebidding their ramp rates to very low levels (to the allowed minimum) and submitted a rule change proposal requiring participants to always submit ramp rates that reflect their generators technical capability at the time. Our proposal would have essentially required generators to provide a ramp rate to AEMO that is the maximum the generator can safely attain at that time. The AEMC's preferred rule requires generators to submit a minimum ramp rate that is the lower of 3 MW per minute for each aggregated unit or 3 per cent of their maximum capacity, except where they can demonstrate that a lower ramp rate is required for technical or safety reasons.[47] This requirement means that some generators' offers after the rule change would have included ramp rates that allow AEMO to dispatch more capacity than previous but still not near what is technically possible. As a result, ramp rates are still contributing to high prices.

### 4.2.4 Demand forecasting inaccuracies also contribute to price spikes, but AEMO is working on improving its processes

Demand forecasting inaccuracy is another factor contributing to price spikes (box 4.2).

The reliability of demand forecasts is important. AEMO provides a range of long, medium and short term demand forecasts. Market participants and AEMO rely on short and medium term demand forecasts for price forecasts and operational decisions, while long term demand forecasts help businesses make investment decisions. Inaccuracies in demand forecasts can result in inefficient market outcomes and compromised pricing signals that may ultimately affect investment decisions.

Accurately forecasting demand is a complex and difficult task, with many factors informing any forecast. Forecasting demand is likely to become even more complex as the market evolves, for example with greater penetration of rooftop solar photovoltaic installations and other generation or load that does not provide AEMO with their forecasts output or consumption. Demand response participants do not currently have the same obligations for bidding and rebidding as scheduled generators, despite their potential effect, and this situation can reduce the accuracy of AEMO's demand forecasting. Forecasting techniques will need to be agile and responsive to accommodate these challenges.

Given forecasts are based on incomplete information and assumptions, it is not unexpected that demand forecasts will be inaccurate at times. However, evidence suggests there are occasions when demand inaccuracies are a high proportion of actual demand. In summer 2017–18 in Victoria, for example, the highest over and under forecast four hours ahead were around 1500 MW, which equates to around 17 and 30 per cent of demand respectively, or the largest generator in Victoria.

An over forecast of demand can result in participants incurring unnecessary fuel costs and other commitment costs it cannot recover. AEMO also may have taken interventions that were not necessary, such as enacting the reliability and emergency reserve trader mechanism. Conversely, under forecasting demand may leave generation short of fuel, because generators did not account for higher levels of generation. Or, there may not be enough generation

47 AEMC, Generator ramp rates and dispatch inflexibility in bidding, 2015.

committed to coming on, creating a short term supply and demand imbalance.[48]

The AEMC also identified problems with demand forecasting in its Reliability Frameworks Review.[49] It recommended AEMO develop new guidelines for its forecasting methodologies and we monitor AEMO's deviations from its forecasts. AEMO acknowledged its forecasting process must be improved and is currently revising its approach and techniques.[50]

## 4.3 Participant bidding contributed to increased local FCAS costs in South Australia, but this is unlikely to be sustained

In South Australia, costs of FCAS increased significantly over the past five years, as a result of local FCAS providers taking advantage of an increased need for local requirements. This situation is unlikely to sustain given more recent market developments.

Regions at the ends of the NEM can separate from the rest of the NEM if there is a problem with the interconnectors connecting it to neighbouring regions. At these times, the separated region has no access to FCAS from other regions and must source FCAS locally (section 2.4).

AEMO introduced a 35 MW local regulation requirement in October 2015 to maintain system security if the Heywood interconnector between South Australia and Victoria was lost (the 35 MW requirement). Before this requirement, FCAS regulation prices were almost always low, so few participants offered regulation services in South Australia. But from October 2015 to December 2017, the spot price for regulation services in South Australia exceeded $5000 per MW 19 times (sometimes over several days).

While not true in every situation where the 35 MW requirement was invoked, our analysis of these events found there was always enough FCAS offered, but participants either:

- collectively offered less than 35 MW of FCAS at prices below $5000 per MW a day ahead
- rebid from low to high prices during the day so there was less than 35 MW of low priced capacity available, which meant high price FCAS was needed.

More information on these events is in appendix A.

Only a few thermal participants were able to provide FCAS in South Australia over this period, so these participants had market power when AEMO sourced FCAS locally.

Initially, only three generators (from three companies) could provide FCAS in South Australia over this period: Northern (Alinta Energy), Pelican Point (Engie) and Torrens Island (AGL Energy). The market responded to the high prices, with Origin Energy registering the Quarantine and Osborne units to provide regulation services during 2016. But Northern power station exited the market in May 2016 and high prices continued. Further capacity entered the market with the South Australian Government investing in the Hornsdale Power Reserve, which provided FCAS in December 2017. Supported by funding from the Australian Renewable Energy Agency, the Hornsdale wind farm started providing services in March 2018 (figure 4.14). This change increased the number of participants and supply of FCAS in South Australia and coincided with a reduction in the number of high price events. There has only been one event since (on 8 July 2018), which was caused by different factors than the previous 19 events.[51]

AEMO removed the 35 MW requirement in October 2018, because participants can now provide enough FCAS locally, as a result of the synchronous generation requirements. Given these developments, it is unlikely the issues in South Australian regulation FCAS markets experienced in recent years will be sustained.

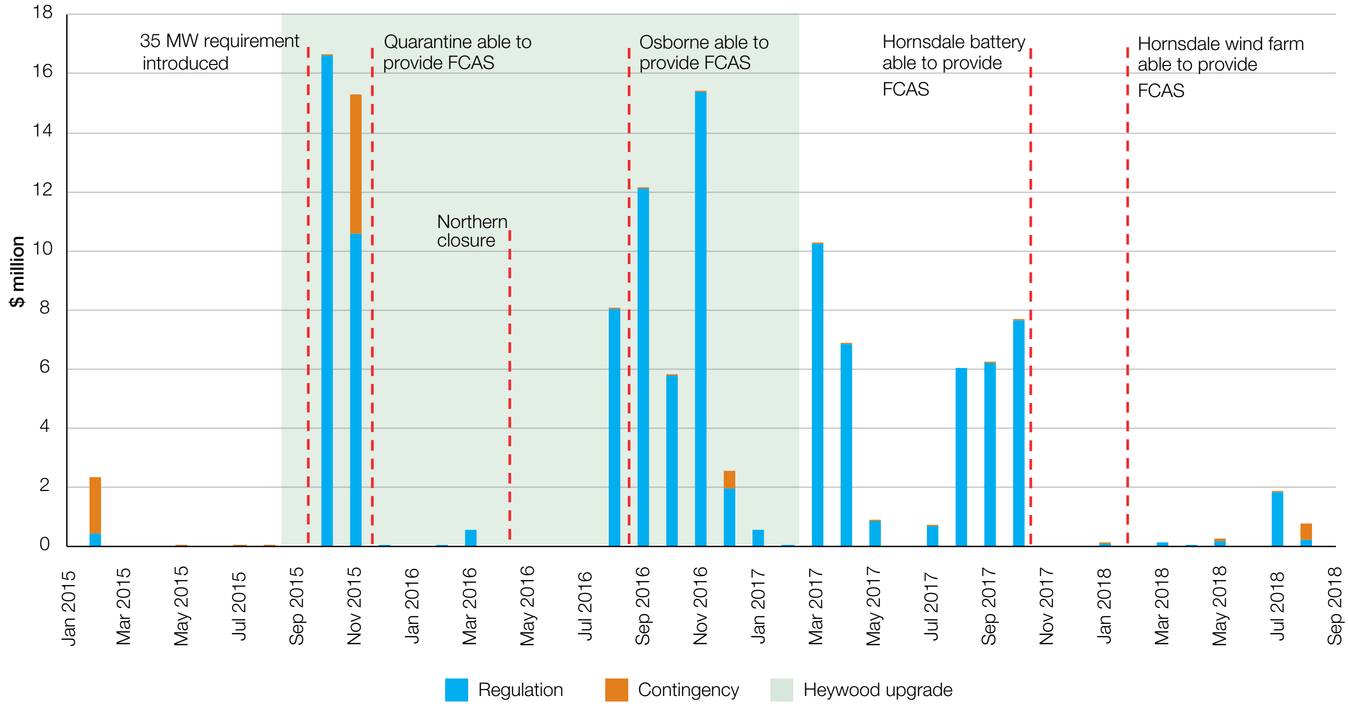
48 For example, on 18 January 2018, when prices exceeded $5000/MWh in Victoria, demand forecasts issued four hours previous underestimated demand by up to 638 MW.

49 AEMC, *Reliability Frameworks Review—Final report*, July 2018.

50 AEMO, *Observations: Operational and market challenges to reliability and security in the NEM*, March 2018.

51 The 8 July 2018 FCAS event was due to a combination of the 35 MW requirement and a special pricing arrangement introduced as a result of market intervention.

**Figure 4.14 FCAS costs and events in South Australia, 2015–2018**




Sources: AEMO data, AER analysis.

# 5. Prospects for new investment

## Key points

- Significant coal capacity has exited the market and, while there has been new entry, supply and demand conditions have tightened in recent years.
- This new entry has been in wind and large scale solar, driven by the renewable energy target (RET), recent high electricity prices, and the declining cost of wind and solar technology.
- Price signals for new entry that does not rely on additional funding (for example, through the RET) to be viable appear to be emerging, particularly for wind and large scale solar.

Understanding entry and exit in the national electricity market (NEM) is important to assessing the market's performance over time. An efficient wholesale electricity market typically requires a mix of demand and supply side options. Market led entry and exit promotes dynamic efficiency by ensuring energy is delivered at least cost over time. The threat of potential new entry is also an important feature of effectively competitive markets, because it counters participants' ability to exercise sustained market power.

This chapter discusses investment conditions in the NEM and the extent to which the market supports efficient entry and exit:

- Section 5.1 shows significant coal capacity has exited the market and, despite some new entry, supply and demand conditions have tightened.
- Section 5.2 reveals price signals for new entry may be emerging, particularly for large scale solar and wind.
- Section 5.3 finds our results are largely consistent with what we are observing in the market.

## 5.1 Supply and demand conditions have tightened

For much of the past decade, the NEM was characterised by low wholesale prices. These low prices were due to an oversupply of generation capacity and low fuel costs. This oversupply peaked in 2014 following six years of declining electricity consumption.[52]

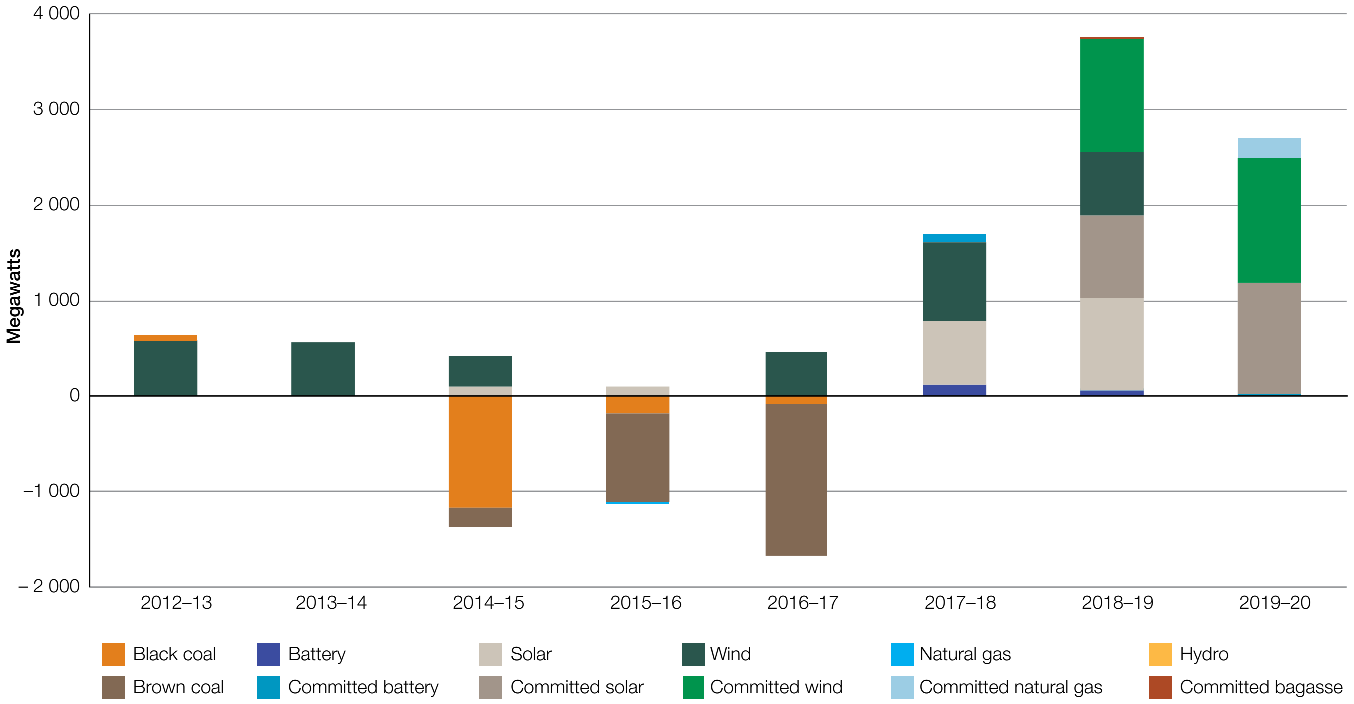
Since 2014–15 demand has stopped declining, and eight coal generators, totalling nearly 4000 MW of capacity, have exited the market (figure 5.1). Many of these generators had reached the end of their economic life. Over the same period, around 5300 MW of new wind and solar capacity has entered the market. But this investment hasn't been sufficient to offset the impact of coal generator exits. Wind and solar have lower average availabilities than the coal plant that exited, so it has not been a like-for-like replacement. There has also not been significant investment in related 'firming' capacity provided by flexible generation technologies (section 2.1).[53]

As a result, supply and demand conditions have tightened across the market in recent years. This, combined with high fuel prices and increased generation from higher cost sources, has led to increased prices across the NEM. While prices have eased in most regions in 2018, they still remain high by historical standards.

52 AEMO's 2014 Electricity Statement of Opportunities (ESOO) reported that no new capacity was required in any NEM region for 10 years, and that there was potentially over 7650 MW of surplus capacity across the NEM.

53 Firming technologies are those that can be called upon to generate electricity at any time. These technologies can be used to 'firm' the supply from intermittent generation.

**Figure 5.1 New and committed investment and withdrawn capacity in the NEM**




Notes: Additional and withdrawn capacity presented captures scheduled and semi-scheduled generators only, capacity from non-scheduled generators is not included. Additional capacity includes new generators entering the market and capacity added to existing generators in upgrades. Shifting generators from non-scheduled to scheduled category is not considered as additional capacity. Withdrawn capacity includes retired generators and reduced capacity from existing generators.

Source: AEMO data, AER analysis.

### 5.1.1 Significant coal capacity has exited the market

The exit of coal fired generators in the NEM has been driven by a range of factors, including generation oversupply, ageing plant and declining demand.

The most recent low cost generator to exit the market was Hazelwood power station, a 1600 MW generator located in Victoria. Before it closed in March 2017, it was a large presence in the market, representing around 15 per cent of installed capacity and supplying 20 per cent of electricity in Victoria. Its exit had a significant effect on prices, particularly due to its large capacity, low fuel cost, and central location.[54]

The next coal fired generator scheduled to exit the NEM is the 1800 MW Liddell power station in New South Wales (NSW), in 2022 when it will be 50 years old. Liddell represents about 11 per cent of installed capacity in NSW, and it supplied around 13 per cent of the state's electricity in 2017–18. The new requirement of three years notice prior to scheduled and semi-scheduled generator exits,[55] and the age of other coal fired generators in the NEM, means it is unlikely another coal fired generator will exit before Liddell.

### 5.1.2 Most new entry in recent years has been in renewables

In recent years, almost all investment in new capacity has been in renewables, namely wind and solar. Since 2014–15, around 3400 MW of wind and around 1850 MW of large scale solar capacity has entered the NEM. As noted in section 2.1, there has also been significant investment in rooftop solar over the past five years.

There is significant future investment in wind and solar generation, supported by the RET and emissions reduction initiatives (figure 5.1). At the time of writing, there is 2040 MW of committed large scale solar projects and 2489 MW of wind.[56]

Under the RET, generators create large scale generation certificates (LGCs) for each megawatt hour of electricity generated from renewable energy sources. They can then sell or transfer their LGCs to entities (mainly retailers) who are required to obtain and surrender a number of these certificates in proportion to the electricity they acquire in a year.

54 Our report explores the effect of the Hazelwood power station's exit, particularly on the Victorian and South Australian markets.

55 https://www.aemc.gov.au/rule-changes/generator-three-year-notice-closure.

56 AEMO, Generation information page. http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information, accessed 23 November 2018.

Looking forward, the Clean Energy Regulator's October 2018 LGC market update indicates the value of LGCs has fallen significantly.[57] Market participants indicated some wind and solar investments attributed no value to the LGCs. This suggests the current high prices mean wind and solar investments may no longer require the support of mechanisms like the RET to be commercially viable.

### 5.1.3 There are challenges associated with the changing generation mix

The changing generation mix has led to an increased focus on power system security and reliability (box 5.1).

While conditions have tightened in recent years, there is still sufficient capacity in the NEM to meet current expected demand and the Australian Energy Market Commission (AEMC) does not expect the reliability standard to be breached in the medium term.[58] However, the Finkel review and the Australian Energy Market Operator (AEMO) have pointed to a need for additional generation capacity in the longer term.[59]

Separately, the changing generation mix means the system is facing increasing security challenges. The retirement of older coal fired generators, combined with the surge in variable renewable generation investment, has created challenges in managing the security of the power system. In addition to providing energy, older coal fired generators play a critical role in supplying ancillary services that help maintain system frequency within standards. They also provide other characteristics necessary for maintaining power system security.

To maintain system security and a reliable operating state AEMO has increasingly used its directions powers to keep certain generators operating. The high proportion of solar and wind generation in South Australia, for example, means AEMO at times has to limit wind generation and direct on gas generators to maintain the power system in a secure state.[60] This intervention has occurred more frequently since late 2017, with AEMO now intervening in around 30 per cent of dispatch intervals in South Australia.

A range of reform processes are underway to address some of these issues (chapter 7).

### 5.1.4 Investment in flexible gas capacity has been low recently, but storage is starting to emerge

With the rise in more intermittent generation and the exit of large thermal capacity, there may be an increased need for flexible generation or storage that is able to effectively contribute to maintaining power system security.

After the NEM started in 1998, significant new flexible capacity entered the market, including 16 open cycle gas turbine (OCGT) generators. The last new OCGT generator commissioned in the NEM was Origin Energy's Mortlake 550 MW generator in Victoria in 2011.

Currently, there is only 232 MW of committed new flexible capacity for the NEM. This includes AGL Energy's 210 MW Barker Inlet reciprocating gas power station, which is replacing part of the Torrens Island A gas fired boiler generator. This low level of investment persists despite AEMO assessing a need for reliability and emergency reserve trader (RERT) capacity over two consecutive summers.

The role of storage in a market transitioning to an increased penetration of intermittent renewables is starting to grow. There has been some investment in battery scale storage in the NEM, supported by Australian Renewable Energy Agency (ARENA) trials. In December 2017, the Hornsdale Power Reserve began operating as the first grid-scale lithium ion battery storage facility, at 100 MW capacity. Of its total capacity, 70 MW is reserved for power system reliability, while the remaining 30 MW is operated commercially by storing energy from the NEM and selling it into the market. The Hornsdale Power Reserve also participates in the frequency control ancillary services (FCAS) markets (see section 4.3). Since then, AEMO reports 107 MW (75 MW in Victoria, 30 MW in South Australia and 2 MW in Queensland) of new battery storage have commenced or been committed.

57 Clean Energy Regulator, *Large scale generation certificate market update—October 2018*.

58 AEMC, *Frequency control frameworks review—Final report*, 26 July 2018.

59 Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*. June 2017; AEMO, 2018 Electricity statement of opportunities, August 2018.

60 AEMO, *Observations: Operational and market challenges to reliability and security in the NEM*, March 2018, pp 8, 25.

### Box 5.1 Power system security and reliability[61]

The power system is secure if it is able to operate within defined technical limits (such as frequency, voltage and current flow limits) and maintain supply to customers even if there is an incident such as an unplanned network or generator outage. The Australian Energy Market Operator is responsible for maintaining and improving power system security.

The power system is reliable when there is enough generation and network capacity to supply customers with the energy they demand. A range of factors affect the reliability of the power system including: the investment, retirement and operational decisions of market participants; the reliability of the distribution and transmission networks; and whether the power system is in a secure operating state. The reliability standard currently requires there be sufficient generation and transmission interconnection so that 99.998 per cent of annual demand is expected to be supplied. This means an average customer may not have their electricity requirements met for about 10.5 minutes per year and the power system will still be considered reliable.

## 5.2 Price signals for new entry appear to be emerging

As highlighted in the previous section, there has recently been considerable investment in wind and large scale solar, and more is committed. However, much of this was supported by schemes such as the RET. It is important to assess whether, in the absence of these subsidies, signals for new entry are emerging and for what technologies.

### 5.2.1 We modelled incentives for new entry to assess the performance of the market

In an efficient, competitive market, with low or no barriers to entry and exit, we expect prices to move broadly in line with underlying costs. In this market, if prices (and therefore, revenue) are persistently higher than underlying costs, investors will see an opportunity and enter the market. To the extent this new entry is lower cost, then this should bring prices down. Alternatively, if prices persist below underlying costs, it will eventually become unprofitable for high cost firms to remain in the market, and they will leave. Over time this will cause the price to rise.

An efficient wholesale electricity market involves a dynamic mix of supply and demand side options. In equilibrium, the market should deliver the right mix of generation and prices should adjust so that each of these generation types earns a competitive return on its investment. If we observe that prices are higher than a new entrant's costs for a sustained period and there was no market led investment response, then we might be concerned the market was not performing as intended.

We undertook modelling comparing potential spot revenue to estimated costs of production for new entrants to assess whether current spot prices reflect the underlying costs of new entry.[62]

Investment decisions are unlikely to be made based on spot outcomes alone. In deciding when to invest, new entrants are likely to take account of range of other factors, with future expected revenues and contract arrangements more likely to drive investment than historic spot prices. Contract arrangements for the sale of electricity, in particular, are important for new entrants (box 3.5). Establishing contracts insures against spot price volatility, and provides revenue certainty, which supports investment. New entrants would also consider other potential sources of revenue, such as the provision of FCAS or other system services (box 2.3).

The National Electricity Law requires us to use public information in the first instance. Unfortunately, there is limited public data on contract prices, particularly for over the counter arrangements. Prices for ASX traded products provide a good indicator of future prices. However, these typically trade only 18 months ahead. While they may not provide a complete picture of investment incentives, we have used spot prices in our analysis as they are publicly available.

To calculate spot revenues we assessed spot prices in 2017–18 and 2014–15 in all regions. We chose the 2014–15 financial year as a comparison point because it marks the financial year before prices across the NEM began rising, it did not include carbon pricing, and it is the period at which oversupply in the market peaked. From the chosen years, we estimated the potential spot revenue a new entrant generator could receive depending on its capacity factor (box 5.2).

61 Adapted from Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*. June 2017; AEMC, Keeping the energy system secure and reliable, viewed October 2018.

62 As required by the National Electricity Law, section 18B(b).

### Box 5.2 What is capacity factor?

The capacity factor is the amount of energy produced by a generator, expressed as a proportion of its maximum possible production over a given period.

Capacity factor is significant in our calculations as the fixed costs associated with generation are allocated across each megawatt hour of energy produced. This means a small change in capacity factor can have a significant impact on cost estimates. The higher the capacity factor, the lower the levelised cost per megawatt hour becomes. This means, at higher capacity factors, less revenue is required per megawatt hour of production to recover those costs

Given the significance of capacity factor, we estimate costs across a range of potential capacity factors, rather than for a single chosen value. This results in a range of possible costs estimates from 0–100 per cent. However, no generator can operate 100 per cent of the time. Accordingly, we truncated our calculations at certain capacity factors, partly based on the current capability observed for each technology type.

Our cost estimates are based on a range of publicly available general information on costs and include both high and low cost scenarios for a range of technologies. New entrants would also consider more site-specific detailed modelling of costs, risk and production not captured in this analysis. As our analysis focuses on new entry, we did not model incumbent generators' costs or potential revenues.

We levelise our cost estimates, meaning that a new entrant generator's lifetime costs are allocated across each megawatt hour of energy its produces over its expected life. This creates a minimum price at which a generator will need to sell its electricity in order to recover its costs.

There are a number of significant limitations of this analysis. We did not model all technologies (including hydroelectricity and storage) and we made some simplifying assumptions, including only modelling costs in 2017 Australian dollars. Our analysis is also retrospective, to see if the investment the market delivered aligned with what might have been expected, based on spot price outcomes alone.

Despite these limitations, we consider the analysis is a helpful tool for understanding how investment price signals are adjusting over time for a range of technologies. It provides a benchmark, which along with a range of other information, we can use to assess how the market is performing over time. More detail on our approach (including its limitations) and detailed findings are set out in the AER *LCOE Modelling Approach, Limitations and Results (December 2018)*.

### 5.2.2 What do our results show?

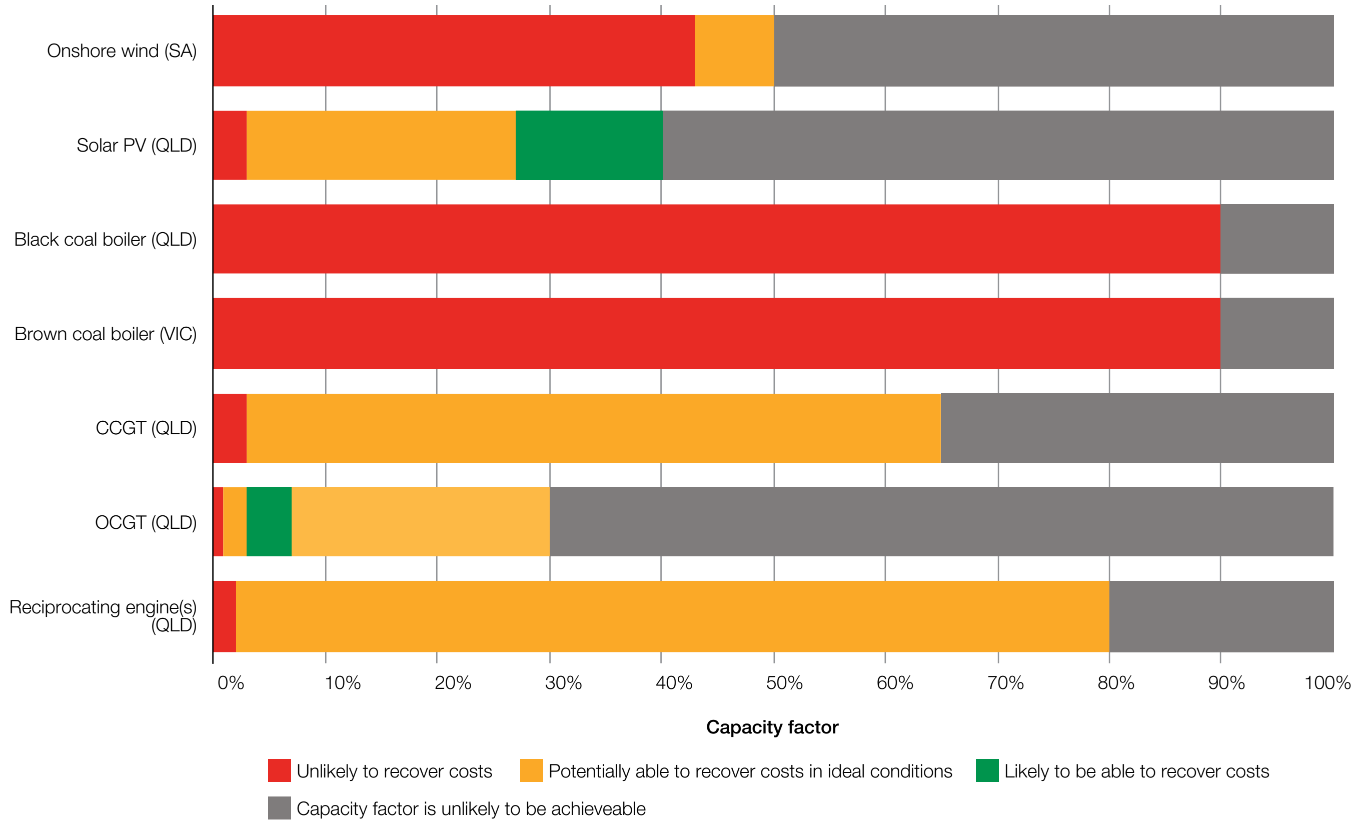
Our findings suggest for some technologies, a potential price signal for new entry is emerging. As noted above, we chose 2014–15 as a comparison year because it is the financial year before prices across the NEM began rising, it did not include carbon pricing, and it is the period at which oversupply in the market peaked. As the prices (and revenue) in the spot market have risen, so too has the likelihood of a new entrant generator recovering its costs.

Figures 5.2 and 5.3 present summary results based on the regions with the highest potential spot revenue for each technology in 2014–15 and 2017–18. In these charts, the colour indicates the likelihood of cost recovery for a new entrant at different capacity factors. Red coloured sections represent capacity factors where a new entrant would be unlikely to recover its costs. Conversely, green coloured sections indicate capacity factors where a new entrant would be more likely to recover its costs (above our modelled high cost scenario). Yellow coloured sections show capacity factors in which a new entrant would potentially be able to recover its costs, in ideal conditions (above our low cost scenario). Grey sections are levels of production at capacity factors that are typically beyond the current capability observed for this technology type.

The modelling suggests while some technologies may have recovered costs in 2014–15, the investment price signals are much stronger in 2017–18, with new entrant wind, large scale solar photovoltaic (PV) and combined cycle gas turbine (CCGT) technologies being the most likely to have recovered their costs.

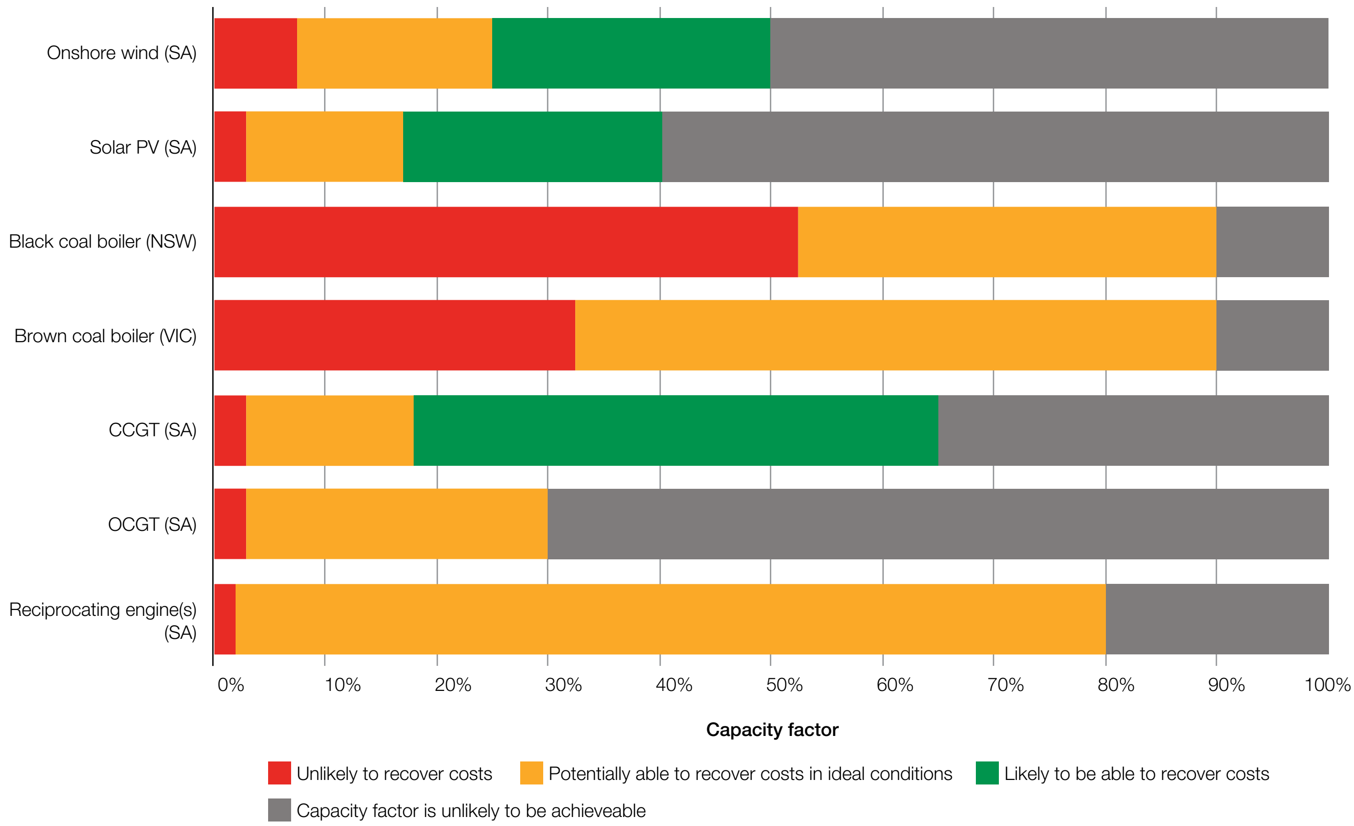
These results suggest an emerging signal for new entry of those technology types (based on spot 2017–18 revenue alone). However, high average spot prices are a relatively recent trend and, as noted above, new entrants will take into account a range of factors in deciding whether to invest.

**Figure 5.2 Likelihood for new entrant cost recovery for 2014–15 by technology type**




Source: AER, *LCOE Modelling approach limitations and results*, 2018.

**Figure 5.3 Likelihood for new entrant cost recovery for 2017–18 by technology type**




Source: AER, *LCOE Modelling approach limitations and results*, 2018.

Our results also enable us to make some observations about the price signals for investment for different technologies. There is an emerging price signal for investment in large scale solar, for example, even without support like the RET. The price signal for investment in solar is stronger in 2017–18 than in 2014–15. While the higher prices observed in 2017–18 contributed to this finding, new entrant solar costs are also falling.

Large scale solar is a developing technology and has seen rapid cost reductions in recent years. The International Renewable Energy Agency (IRENA) reported utility-scale solar photovoltaic (PV) costs globally fell by 40–75 per cent between 2010 and 2017, for example. In Australian-only costs, the same report quoted a 44 per cent reduction in commercial solar PV costs (up to 500 kW system size) between 2014 and 2017.[63] Similarly, ARENA also reported a 40 per cent drop in the total project costs for large scale solar projects applying for funding between 2014 and 2016.[64]

There is also an emerging price signal for investment in wind, even without the support of the RET. Like solar, this price signal for investment was stronger in 2017–18 than in 2014–15. Recent high average prices contributed to this finding. In addition, while more mature than solar, wind has also benefited from rapid reductions in costs in recent years. IRENA reported levelised costs of onshore wind projects globally fell by nearly 50 per cent, for example, and Australia has benefited from these cost reductions.[65]

Our analysis suggests the flexible, firming technologies we modelled (such as OCGT) could possibly recover their costs in a best case scenario, but the investment signal is not as strong as for other technologies. This has important implications, as there will be a greater need for these forms of firming generation as we shift to a generation mix that relies increasingly on intermittent generation sources.

The key reason for this need, as noted in section 2.2, is that while we have seen a general uplift in prices NEM-wide, we are not seeing the price spikes that support the low capacity factors that technologies such as OCGT operate within. Under our analysis, this has changed the shape of the revenue curve, reducing the potential spot revenue a generator could earn by operating at low capacity factors.

The trend to a general uplift in prices without high volatility also improves the signals for investment in some technologies that operate at higher capacity factors. For this reason, we see a potential price signal emerging for CCGT plant. However, this signal may not be sustained given the expected influx of new renewable generation capacity. Our results suggest that investment signals for new coal technologies also improved somewhat, but based on current prices and cost estimates were not as strong as CCGT, wind or solar technologies.

## 5.3 Our results are largely consistent with what we are observing in the market

Our findings on the price signals for investment for various technologies are generally consistent with what we are observing in the market and what we understand from our enquiries.

As noted earlier, there is significant investment in wind and solar on the horizon. Australia is particularly well suited to wind and solar due to our abundance of sunshine and strong winds, the absence of harsh winters, and a seasonal peak in summer when solar is most effective. Wind and solar are also modular and not subject to significant economies of scale, which facilitates investment in these technologies by allowing investors to enter on a small scale without significant capital investment. Further, as noted earlier, there are continuing improvements in technology and significant reductions in cost for wind and solar.

While there hasn't been significant investment in new CCGT capacity, previously mothballed units have returned to service. Engie returned the second unit of its South Australian Pelican Point plant to service in mid-2017 after withdrawing it from service in April 2015. There is no further generation investment in CCGT committed. However, this might not be unexpected, as the recent price signals we have observed might not be sustained as the market transformation continues.

Our enquiries also confirmed the investment environment for new coal fired generation is challenging. Coal fired generators are large units with high fixed costs that need to be recovered over many years. The shift towards more use of lower cost but intermittent generation indicates a greater need for plant that can operate flexibly. Coal fired plant tends to be inflexible, relying on relatively constant high production levels because frequent start-up, shut-down, and ramping leads to increased fuel, maintenance, and operations costs. This inflexibility raises the risk that a new coal plant will be underutilised with increased penetration of intermittent generation. Further, the high emissions profile of coal-fired generators has led to Engie, Origin Energy and AGL Energy

63 IRENA, *Renewable power generation costs in 2017*, January 2018.

64 ARENA, *Large scale solar photovoltaics—competitive round*, https://arena.gov.au/funding/programs/advancing-renewables-program/large-scale-solar-photovoltaics-competitive-round/, accessed 21 November 2018.

65 IRENA, *Renewable power generation costs in 2017*, January 2018.

all signalling their intention not to invest in coal plant in future.[66]

However existing incumbent generators–particularly coal fired generators–can still have significant cost advantages and remain economic in the market because of, for example, sunk capital costs and relatively low fuel costs. This could change if the costs of constructing wind and solar decline more rapidly, or if policies that erode the cost advantage of existing plant (such as emissions pricing) are introduced.

The observations on flexible capacity have perhaps the most significant ramifications for the market. Because renewable generation is intermittent, increased penetration of this type of technology in future may mean that the system requires additional flexible capacity that can respond to the changes in renewable energy output to manage potential reliability and security challenges (section 5.1.3). Both the Finkel review and AEMO have identified a need for flexible generation as the penetration of renewables increases.[67] Our analysis suggests that some fast response flexible technologies, such as OCGT, cannot readily recover their costs at current spot prices.

We note, however, that while we are not seeing the price spikes that many flexible technologies require to be viable, we may see price spikes emerge in future with more intermittent generation. However, AEMO has also noted that the current influx of renewables will reduce wholesale prices in some of the periods that flexible capacity currently operates and that price spikes alone may not be adequate to drive new investment.[68]

Studies are being undertaken to understand the feasibility of a range of proposed flexible capacity projects in the NEM. Notably, both Snowy Hydro and Hydro Tasmania have announced plans to add significant hydroelectric storage capacity to the NEM. Snowy Hydro's proposed Snowy 2.0 expansion would create 2000 MW of pumped hydroelectric storage. Hydro Tasmania's proposed 'Battery of the Nation' project would see a range of expansions and developments (including additional interconnectors between Victoria and Tasmania). At full implementation, this project would add 2500 MW of pumped hydroelectric storage to the NEM.

Given the importance of flexible capacity in the overall generation mix, we will need to monitor the investment trends in these technologies going forward.

66 http://www.engie.com/en/journalists/press-releases/2016-integrated-report/, accessed 5 November 2018; https://www.originenergy.com.au/about/investors-media/media-centre/origin-to-halve-emissions-in-line-with-paris-2c-goal.html, accessed 5 November 2018; https://content.agl.com.au/wp-content/uploads/2017/04/AGL_Greenhouse_Gas_Policy.pdf, accessed 22 November 2018 (conditional upon carbon capture and storage).

67 Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*. June 2017; AEMO, Integrated System Plan. 2018.

68 AEMO, *Observations: Operational and market challenges to reliability and security in the NEM*, p 34.

# 6. Barriers to entry and impediments to efficient price signalling

## Key points

- Market enquiries identified a range of potential barriers to entry and impediments to efficient price signalling in the national electricity market (NEM). A lack of policy consistency is seen as a key barrier to entry in the NEM.
- Notwithstanding these barriers, we expect to see significant investment in some generation technologies, particularly wind and large scale solar. Barriers to entry and impediments to efficient price signalling raise a concern, however, that we may not see the required investment in flexible capacity required to support the increased reliance on intermittent wind and solar generation.

As highlighted in the previous chapter, price signals for new investment appear to be emerging for some technologies. Understanding the nature of barriers to entry and impediments to efficient price signalling helps us assess whether new entry might occur in response to these emerging price signals. For technologies where we do not currently see an investment signal, understanding barriers and impediments to efficient price signalling helps us assess whether we may see investment if these signals emerge.

New entry is also an important feature of effectively competitive markets, because it may constrain participants' ability to exercise sustained market power. It is also important to understand the effect of barriers to entry in this context.

This chapter discusses barriers to entry in the NEM and the extent to which the market supports efficient entry and exit:

- Section 6.1 identifies a range of potential barriers to entry and impediments to efficient price signalling entry in the NEM.
- Section 6.2 explains these barriers to entry are creating a risk that expected new entry may not eventuate for some technologies.

## 6.1 Barriers to entry issues raised during market enquiries

### 6.1.1 Market concentration, vertical integration and contract market liquidity may affect new entrants

Chapter 3 discussed the concentrated nature of the generation sector across the NEM and the extent of vertical integration. Our enquiries suggested that industry structure creates a challenging investment environment, particularly for a new entrant.

To invest, generators require revenue certainty, not only for several years, but well into the future. Participants indicated it is difficult to attract debt finance without long term contracts in place to provide this revenue certainty. To provide revenue certainty, counter parties to these contracts also need to be credit worthy and seeking contracts in large volumes. Participants noted there are few counter parties that meet these criteria. The Australian Competition and Consumer Commission (ACCC) Retail Electricity Pricing Inquiry also identified this as a market failure.[69]

Participants also described difficulty in contracting, even where suitable counter parties exist. Many potential counter parties have already satisfied their obligations through vertical integration and/or contracting, and have no commercial incentive to enter into additional agreements. Some generation-only participants are considering taking on retail customers to provide revenue certainty.[70]

More generally, concerns were raised about liquidity in contract markets and the impacts this was having on investment signals (see section 3.5). Contract markets need to be liquid to support an efficient market.

69 The ACCC's recommendation four proposed the Australian Government enter into low, fixed-price energy offtake agreements for the later years of appropriate new generation projects to deal with this issue.

70 For example, Delta Electricity obtained a retail authorisation in 2017 to provide a natural hedge for its generation business. https://www.aer.gov.au/retail-markets/authorisations/public-register-of-authorised-retailers-authorisation-applications/sunset-power-international-pty-ltd-trading-as-delta-electricity-authorised-electricity-retailer.

There has been a downward trend in the volume of contracts traded in recent years (figure 6.1). There are fewer contracts traded on the over the counter markets compared with the Australian Securities Exchange, especially over the past three years.

The decline in trade across these markets may be at least partly due to increasing levels of intermittent generation (section 2.1). As more dispatchable generators retire and are replaced with intermittent generation, trade in contract markets could decline further. A general easing of demand, and less price volatility in the wholesale market may also have contributed to reduced contracting volumes.

The growth of vertical integration may also have contributed to the decline in trade, because participants have less need to buy and sell contracts to hedge their position. That said, vertically integrated generators are unlikely to have the mix of generation assets in each region to exactly match their retail loads. Consequently, they also trade in the contract markets to reduce their exposure to spot prices. The Finkel review, ACCC and the Australian Energy Market Operator (AEMO) each found liquidity in the contract market is low or has declined.[71] They attributed this outcome, in part, to increased vertical integration.

### 6.1.2 The need for policy consistency

In our enquiries for this review, we heard policy durability was critical if we are to see investment in what can be very high-cost and long-lived assets.

A number of energy market reviews in recent years have identified emissions policy instability as a key impediment to investment in the NEM. Notably, the Finkel review highlighted:

> *The uncertain and changing direction of emissions reduction policy for the electricity sector has compromised the investment environment in the NEM… It is critically important that there is widespread political and community acceptance of the need for a stable policy framework.*[72]

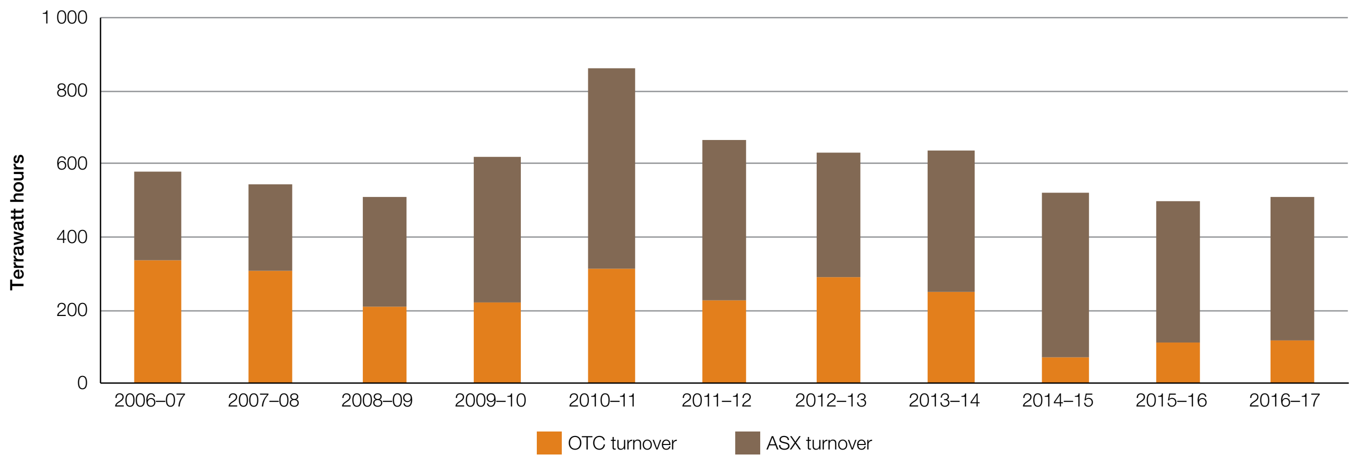
The introduction and subsequent removal of a carbon pricing scheme and changes to the renewable energy target (RET), in particular, have been cited as examples of emissions policy changes that have affected investor confidence.

EnergyAustralia highlighted the importance of credible and durable emissions policy settings:

> *Policy frameworks need to be perceived as credible by investors if they are to achieve efficient and effective outcomes. Even an astutely designed policy with relatively strong incentives for change will struggle to catalyse the required investment unless it is perceived by investors to be politically secure and robust at the outset. This is particularly acute in the case of investments with long time horizons such as those typically required in the NEM.*[73]

In addition to emissions policy consistency, participants identified the need for consistency across other aspect of energy market policy. Initiatives to address reliability or affordability concerns also distort market signals and have an unintended effect on the drivers for future investment. Market participants noted that interventions in the market such as the Queensland Government's directions to Stanwell

**Figure 6.1 Electricity derivative markets turnover (volume)**




Source: AFMA, *the AFMA electricity derivative turnover report,* 2018.

71 Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*. June 2017; ACCC, *Retail electricity pricing inquiry—final report*, June 2018; AEMO, *Observations: Operational and market challenges to reliability and security in the NEM*, March 2018, pp. 51–52.

72 Dr Alan Finkel AO et al, *Independent review into the future security of the national electricity market, blueprint for the future*. June 2017, p. 75.

73 EnergyAustralia, Submission to Finkel review, p. 8.

(section 3.4.2) and South Australian Government's directions following the black system event have disincentivised new entry. These interventions may have short term benefits to the market and consumers, but they may also dampen price signals in the short term and distort the emergence of effective price signals in the medium to longer term.

### 6.1.3 Government ownership as a potential barrier to entry

We also heard government ownership of generation and the potential for further government investment was a barrier to entry.

Historically, government owned utilities ran the entire electricity supply chain in Australia. Currently, the Tasmanian Government owned Hydro Tasmania is the only generator in Tasmania, the Queensland Government owned generators Stanwell and CS Energy control two thirds of Queensland generation capacity, and the Australian Government owns Snowy Hydro.

While government investment may be market driven, our enquiries with market participants indicated it is often not perceived to be the case. Market participants argued when government investment has other drivers, it can be of a different form and scale to private sector investment and can be less predictable. Even a perception that government owned players are investing on a non-commercial basis can contribute to investor uncertainty and be a barrier to private investment.

### 6.1.4 Other market interventions can compromise aspects of market efficiency

Our enquiries highlighted that market participants believe market interventions, particularly the reliability and emergency reserve trader (RERT) mechanism, potentially distort price signals.

The RERT is a type of strategic reserve that allows AEMO to contract for additional capacity to be on stand-by when it forecasts there will not be enough supply to meet demand (box 6.1).

AEMO used the RERT mechanism significantly more in 2017–18 than in previous years. The cost over the 2017–18 summer was $51 million (with more than $50 million of the costs coming from Victoria and being passed on to Victorian electricity customers).

AEMO is facing increasing challenges in operating the power system given the tightened demand–supply balance and the increasing penetration of intermittent generation. It stated it planned more extensively for summer 2017–18 because it was the NEM's first summer after the withdrawal of Hazelwood power station in March 2017, and following load shedding events in summer 2016–17.

During our enquiries, many market participants noted the increased use of the RERT was particularly affecting demand response initiatives in the NEM. It was argued market demand response products are now in direct competition with the RERT. Market participants stated the higher priced RERT mechanism is redirecting customers from existing demand response agreements, rather than creating an incentive for new capacity and security services, or new demand response contracts. Large consumers are declining to continue demand response arrangements in favour of the possibility of securing a more lucrative RERT contract, for example. On the other hand views on the RERT among user representatives were mixed. Some were supportive, describing it as a lower cost solution to an occasional problem. Others were concerned about the reasonableness of the cost of the RERT and indicated a preference to incur the risk associated with the reliability standard as it is currently set.

In March 2018, AEMO submitted two rule change requests seeking broad changes to the RERT. In its assessment, the Australian Energy Market Commission (AEMC) will consider the overall RERT framework and the appropriateness of the reliability standard.[74] The reliability standard reflects a trade-off between the cost of higher reliability, which is borne by consumers through higher prices, and the benefits of fewer blackouts.

In its review of the RERT framework, the AEMC proposed improving the transparency of the RERT framework (procurement, activation and costs).[75] It stated because the reserves are out-of-market, it is important there is transparency in how the RERT is used. We agree increased transparency would be valuable in considering whether or not the RERT is providing the right incentives to deliver efficient market outcomes. Greater transparency would also be useful in assessing whether the costs and payments related to the RERT are at an efficient level.

74 AEMC, *Enhancement to the Reliability and Emergency Reserve Trader rule change,* June 2018.

75 AEMC, *Enhancement to the Reliability and Emergency Reserve Trader—options paper*, 18 October 2018, p. 18.

### Box 6.1 The reliability and emergency reserve trader

The reliability and emergency reserve trader (RERT) mechanism allows the Australian Energy Market Operator (AEMO) to contract for reserves such as generation or demand response that are not otherwise available in the market, when a supply shortfall is forecast. These additional reserves are commonly referred to as 'emergency reserves' or 'strategic reserves' because they may only be used as a last resort to avoid unnecessary blackouts, typically during summer when the demand–supply balance is tight.

Examples of reserve that can be procured for RERT include:

- customer load that can be curtailed and restored on demand, which can be large industrial load or a group of aggregated smaller loads
- generation capacity that is not available to the market that can be brought online.

AEMO can enter into these contracts as far as nine months ahead of the projected shortfall, highlighting the importance of accurate forecasts.

Over the summer of 2017–18, AEMO forecast Lack of Reserve (LOR) conditions 31 times. LOR conditions indicate the system may not have enough spare capacity if a major unexpected event occurs, like the loss of a generator or interconnector.

If the market does not respond to LOR conditions, then AEMO may choose to use reserve contracts through the RERT.[76]

When the RERT is activated AEMO invokes intervention pricing which calculates the price based on what would have happened if AEMO had not intervened and the generators were dispatched according to actual requirements.

## 6.2 Impacts of these barriers to entry and market impediments

These barriers to entry and market impediments affect all potential investment to some extent.

However there is significant investment in new wind and solar generation on the horizon, so it may be that these issues are not currently having as significant an effect on the sector as suggested during our enquiries.

But the significance of these barriers and impediments may also depend on the generation technology involved. To the extent that barriers to entry affect investment in these technologies, the height of these barriers are not sufficient to considerably deter investment, given that we expect to see continued investment in solar and wind. The modular nature of wind and solar investment means these forms of investment are not subject to as significant economies of scale and high sunk costs as some other forms of investment. Technology improvements that are lowering costs are also likely a contributing factor.

For some other technologies, it is not clear what impact these barriers to entry and market impediments will have on investment. Some technologies, such as pumped hydroelectricity, are high cost, long term investments. For these technologies, barriers to entry may act to limit an efficient market response. That said, there are a number of proposals currently under consideration. Given the vital role that these flexible technologies will need to play in the future generation mix, it will be particularly important to monitor whether we are seeing expected investment in flexible capacity, should enduring signals for this investment arise.

While these factors may not be having a significant effect on investment currently, we do consider that a lack of consistent policy signals is one of the biggest threats to competition and efficiency over the long term. Consistent policy supports investor confidence and market led investment in the sector. Achieving this policy environment is a significant challenge, but it is very important if we are to have an effectively competitive wholesale electricity market in future.

76 AEMO, *Summer 2017–18 operations review*, May 2018.

# 7. Where to from here?

### Next steps

- We identified several aspects of the market we will analyse in more depth over the coming year. We will continue to monitor the performance of the wholesale market focusing on investment trends and participant behaviour.
- We will also monitor other aspects of market structure such as concentration, frequency control ancillary services (FCAS) market outcomes, contract markets, and the impact of the reliability and emergency reserve trader (RERT) on investment signals and demand side participation.
- A number of existing policy, review and rule change processes are addressing many of the issues we have identified. We will continue to monitor and contribute to reform processes affecting competition in the wholesale markets.

Throughout this report we identified a number of issues that could affect competition and efficiency in the national electricity market (NEM). This chapter discusses our next steps for some of these issues as well as recommendations and reform processes that are underway to address them.

## Supporting a transforming market

There are a number of processes considering the broader challenges associated with the transformation of the energy sector. The Council of Australian Governments (COAG) Energy Council is developing a Strategic Energy Plan for the NEM in consultation with the Energy Security Board (ESB). The purpose of the plan is to provide clarity of direction to market bodies and market participants in the transitioning energy system. The ESB's *Health of the NEM* report also tracks the performance of the electricity system, as well as opportunities for improvement.

The changing generation mix means the system is facing increasing security challenges. A range of reform processes are underway to address some of these issues. For example, the Australian Energy Market Commission (AEMC) has conducted a review of ancillary services markets and regulatory frameworks that underpin frequency control in the NEM to determine whether they will remain fit for purpose in light of the transforming electricity sector. The frequency control frameworks review 2018[77] recommended three rule change requests to improve information transparency around frequency control issues and existing frequency control markets. The report included a work plan, developed by the AEMC, the Australian Energy Market Operator (AEMO) and the Australian Energy Regulator (AER), detailing actions to address these longer term issues.[78]

The AEMC also recommended an explicit mechanism be developed to appropriately value and incentivise the provision of primary regulating services for frequency. It recommended we submit a rule change request on AEMO monitoring and reporting of frequency performance, and that we monitor and report on frequency control ancillary services (FCAS) market performance. We are currently preparing the rule change request for submission in early 2019.

In the meantime we will continue to monitor these markets and report on issues we identify, including in our weekly reports and FCAS $5000 reports.

## Recommendations regarding market concentration

The Australian Competition and Consumer Commission (ACCC) made a number of recommendations regarding market concentration. Currently any acquisitions of existing generators by incumbents in the NEM that increase market concentration will be subject to ACCC review through their normal mergers and acquisitions review process. The ACCC, in its Retail Electricity Pricing Inquiry, recommended further interventions to address concentration in generation markets. Specifically:[79]

- A prohibition on 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 1).
- The Queensland Government should divide its generation assets into three generation portfolios to reduce market concentration in Queensland, with each portfolio separately owned and operated (recommendation 2).

Before the ACCC made its recommendations, the Queensland Government announced it was creating a new publicly owned 'CleanCo' renewable energy generator. It stated CleanCo would have a commercial mandate to increase competition to the energy market at peak demand

77 AEMC, *Frequency control Frameworks Review—Final Report*, July 2018.

78 AEMC, *Frequency control Frameworks Review—Final Report*, July 2018, table 4.1.

79 ACCC, *Retail Electricity Pricing Inquiry—Final Report*, June 2018, pp. 9, 91 and 93.

times when wholesale electricity prices were highest.[80] However, the ACCC considered competition would be better served by three portfolios of a similar size and each with a mix of generation assets. Further the ACCC suggested the Queensland Government should sell two of these portfolios. The Queensland Government has indicated that it does not intend to sell its generation assets[81] and it has also proceeded to establish CleanCo as originally intended.[82]

## Ongoing monitoring of participant conduct

Our analysis of participant bidding behaviour identified issues requiring ongoing monitoring. We will continue to monitor trends in offers of black coal participants in Queensland and NSW in 2019, and may request further information from those participants.

In August 2018 the Treasurer directed the ACCC to hold a public inquiry to monitor the prices, profits and margins in the supply of electricity in the NEM.[83] The inquiry will provide its first report by 31 March 2019, and at least every six months after that until 2025. The ACCC recently released its initial discussion paper seeking submissions on its approach to this task.[84] We will work with the ACCC in 2019 to minimise duplication between our respective wholesale market monitoring roles.

## Investment conditions and barriers to entry

The ACCC also made recommendations regarding investment in the NEM. In particular, it recommended, where private sector banks are unwilling to finance generation projects (due to uncertainty about the future of an industrial or manufacturing business), the Australian Government provide the lacking financial support.[85] The ACCC recommended the government guarantee offtake from a new generation asset (or group of assets) in the later years of the project (say years 6–10 or 6–15) at a low fixed price sufficient to enable the project to meet financing requirements. The Australian Government is looking at options beyond the ACCC's recommendation, focusing on attracting new investment in firm or firmed generation.[86]

We will continue to monitor investment trends and incentives in the NEM, including the potential impact of policy consistency, investment in 'flexible' generation capacity and the impact of proposed reforms in the sector.

## Addressing concerns regarding liquidity in contract markets

Contract markets have also been closely examined in several other market reviews this year including by the AEMC Retail Competition Review and the ACCC Retail Electricity Pricing Inquiry. Both addressed the need for greater transparency in the contracts market to provide better information about market liquidity and forward prices to market participants and regulators.

The ACCC considered the lack of transparency in the over the counter (OTC) market impedes the transmission of price signals and introduces uncertainty for participants and policy makers. It recommended OTC trades should be reported to a repository that we administer and publicly disclose without revealing the parties involved.[87] It noted New Zealand market participants are required to publish contract information on a publicly accessible website.

The AEMC recommended industry make data on OTC electricity contracts available to reveal the total wholesale cost of energy and improve the ability of policy and regulatory agencies to understand the market.[88]

Both reviews also documented particular concern with the contract market in South Australia. The ACCC found in certain regions of the NEM, particularly South Australia, the level of liquidity and the advantages enjoyed by vertically integrated retailers make it difficult for new entrants and smaller retailers to compete effectively in the retail market. The ACCC recommended the AEMC should introduce market making obligations in South Australia to improve trading activity.

The COAG Energy Council has asked the ESB to provide advice on the ACCC's recommendations regarding the contract markets. In September 2018, the ESB issued two consultation papers, one on OTC transparency in the NEM and the other on market making requirements. Its final advice is due in December 2018.

80 Queensland Treasury, https://www.treasury.qld.gov.au/growing-queensland/queenslands-new-cleanco/. Accessed 29 November 2018.

81 Queensland Government, *Asset sales for Queensland on the books under LNP plan,* Media statement, Minister for Natural Resources, Mines and Energy, Dr Anthony Lynham, 11 July 2018.

82 Queensland Government, *CleanCo to make power bills cheaper,* Joint media statement, 30 August 2018.

83 Treasury, *Driving power prices down*, Joint media release, Treasurer and Minister for the Environment and Energy, 23 August 2018.

84 ACCC, *Inquiry into Electricity supply in Australia—Discussion Paper*, 21 November 2018.

85 ACCC, *Retail Electricity Pricing Inquiry—final report,* June 2018, recommendation 4, p. 100.

86 Australian Government Department of the Environment and Energy, Underwriting new generation investments—public consultation paper, October 2018.

87 ACCC, *Retail Electricity Pricing Inquiry—final report,* June 2018, recommendation 6, p. 122.

88 AEMC, *Retail Competition Review—Final Report*, June 2018, pp. 36–37.

We will continue to monitor and contribute to reform processes affecting the contract markets.

## Review of the RERT mechanism and improvements to demand forecasting

The AEMC is currently reviewing the overall RERT framework through its assessment of AEMO's enhancement to the RERT rule change request.[89] As part of the rule change request the AEMC is also considering the appropriateness of the reliability standard.[90] The reliability standard (0.002 per cent unserved energy) is important because the RERT can be triggered and procured if AEMO forecasts the standard will be breached. The draft determination is due on 31 January 2019.

The AEMC has also made a number of recommendations to improve the demand information available to the market, including additional monitoring by us and increased transparency around AEMO's approach to forecasting.[91] The AEMC recommended we submit two rules change requests to require:

- AEMO to prepare a new guideline to develop its forecasting methodologies
- us to produce a quarterly report on the difference between forecast and actual values in the projected assessments of system adequacy (PASA) and pre-dispatch forecast processes.

We are currently drafting the two rule change requests to implement the AEMC's recommendations. AEMO is also currently revising its demand forecasting approach.[92]

## Supporting demand side participation

The AEMC has conducted several reviews to ensure the energy framework allows for the efficient use of demand response. The Reliability Frameworks Review considered whether a new mechanism is needed to allow aggregators to offer demand response directly into the wholesale electricity market.[93] The final report for this review recommended integrating more demand response in the wholesale market by:

- introducing a voluntary, contracts-based short term forward market
- changing the rules to allow consumers to engage multiple retailers/aggregators[94]
- changing the rules to recognise demand response providers on equal footing with generators in the NEM.

The ACCC's Retail Electricity Pricing Inquiry also recommended the AEMC develop a wholesale demand response mechanism that allows third parties to offer demand response directly into the market.[95]

The AEMC subsequently received three rule change requests in response to the last of these recommendations.[96] On 15 November 2018 it published a consultation paper to consider issues raised by the rule change requests with submissions due by 21 December 2018.[97]

We will monitor the effect of proposed changes to integrate more demand response into the market and participants' reactions to any developments, undertaking further analysis where needed. We will also monitor the impact of AEMO's RERT management on market driven demand side participation.

89 AEMC, Enhancement to the Reliability and Emergency Reserve Trader. The draft determination was published in October 2018. The final is due in December 2018.

90 The AEMC requested advice from the Reliability Panel on the appropriateness of the reliability standard; Reliability Panel Advice, 4 October 2018.

91 AEMC, *Reliability frameworks review—final report*, July 2018, p. iii.

92 AEMO, *Observations: Operational and market challenges to reliability and security in the NEM*, March 2018.

93 AEMC, *Reliability frameworks review—final report*, July 2018, p. 45.

94 The AEMC recommended that, subject to the outcomes of relevant trials, AEMO should develop a rule change request to implement multiple trading relationships.

95 ACCC, *Retail electricity pricing inquiry—final report*, June 2018, Recommendation 21, p. 205.

96 Rule requests were received from the Public Interest Advocacy Centre (PIAC), Total Environment Centre (TEC) and The Australia Institute (TAI), as well as from the Australian Energy Council (AEC) and the South Australian Government.

97 AEMC, *Wholesale demand response mechanisms—Consultation paper*, 15 November 2018.

# Appendix A–Additional analysis of participant conduct

## Late rebidding

We looked at the amount of late rebidding in all NEM regions and whether the timing of rebids in the late period had changed (figures A.1 and A.2). Figure A.1 confirms late rebidding is a feature mainly in Queensland and figure A.2 shows on average the timing of late rebids is evenly dispersed over the training intervals in the late rebidding period.

## Physical withholding

When participants rebid, the National Electricity Rules require they provide a code that helps describe why they have rebid. The codes are:

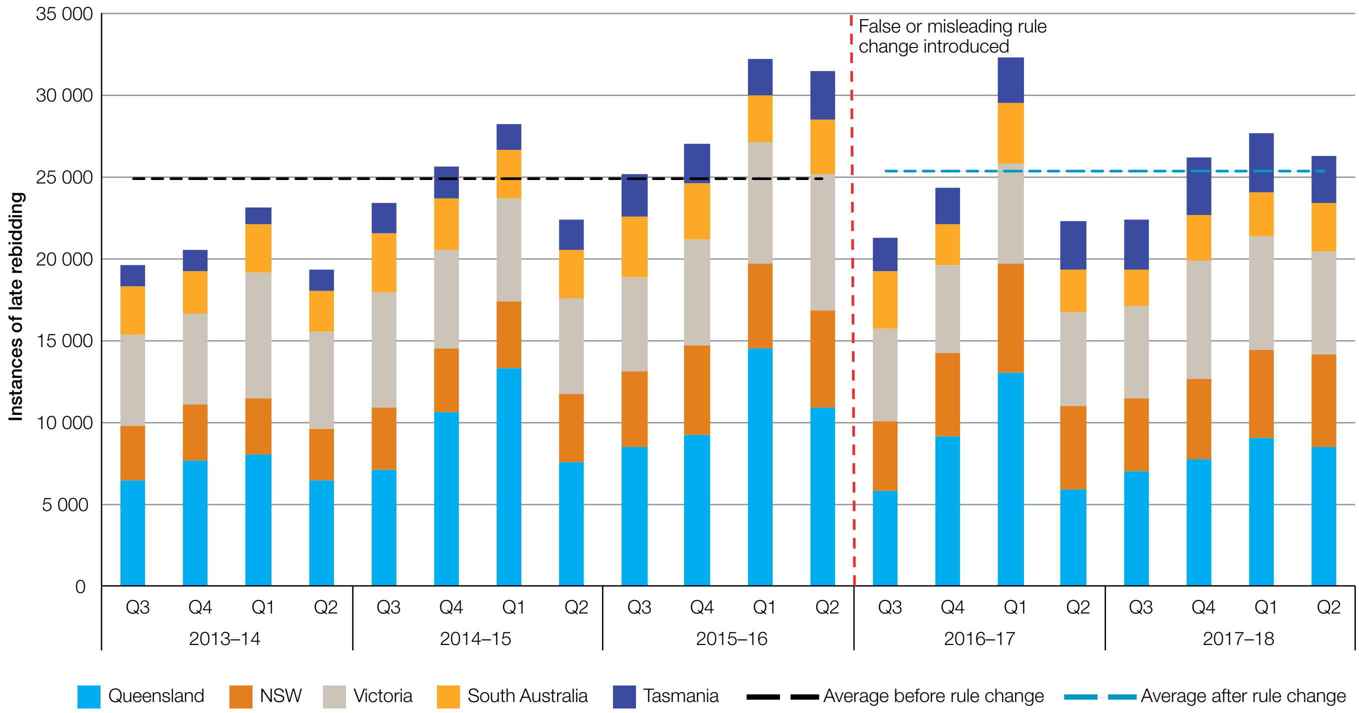
- P for plant issues (for example, unexpected breakdown)
- A for AEMO (Price, demand, direction etc)
- E for error (used if their previous rebid was erroneous)
- F for financial reasons (uneconomic dispatch)

Figure A.3 shows the count by code when they rebid their plant unavailable during a trading day, where we could determine it. Most of the time generators rebid because of plant issues.

In Victoria, the increase in the AEMO category in the last two quarters is due to rebids for Bairnsdale power station. Bairnsdale is an 80 MW gas fired power station owned by Alinta Enegry. A majority of these rebids contained the reason “price different from forecast”.

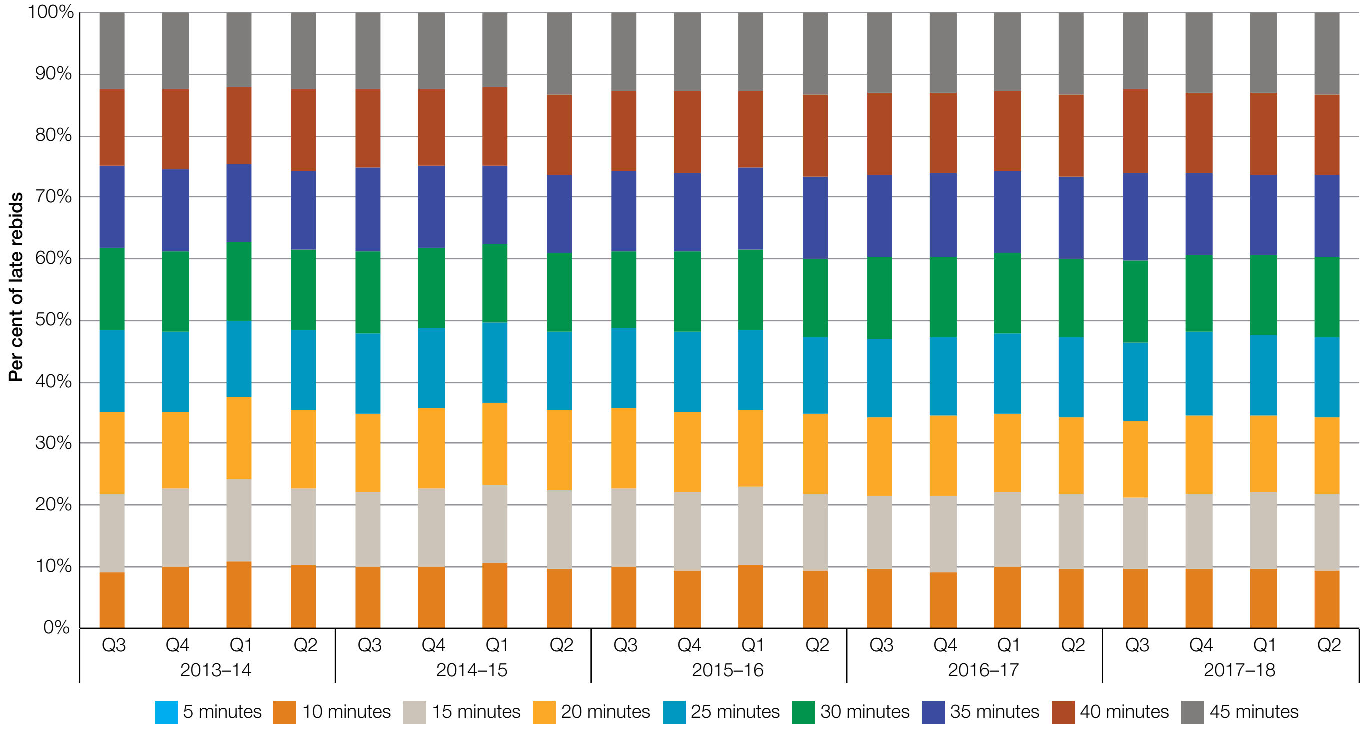
In South Australia, the increase in the plant category from quarter four 2017 relates the Hornsdale battery rebidding to reflect the state of charge of the battery.

**Figure A.1 Late rebidding before and after the rule change for the NEM**



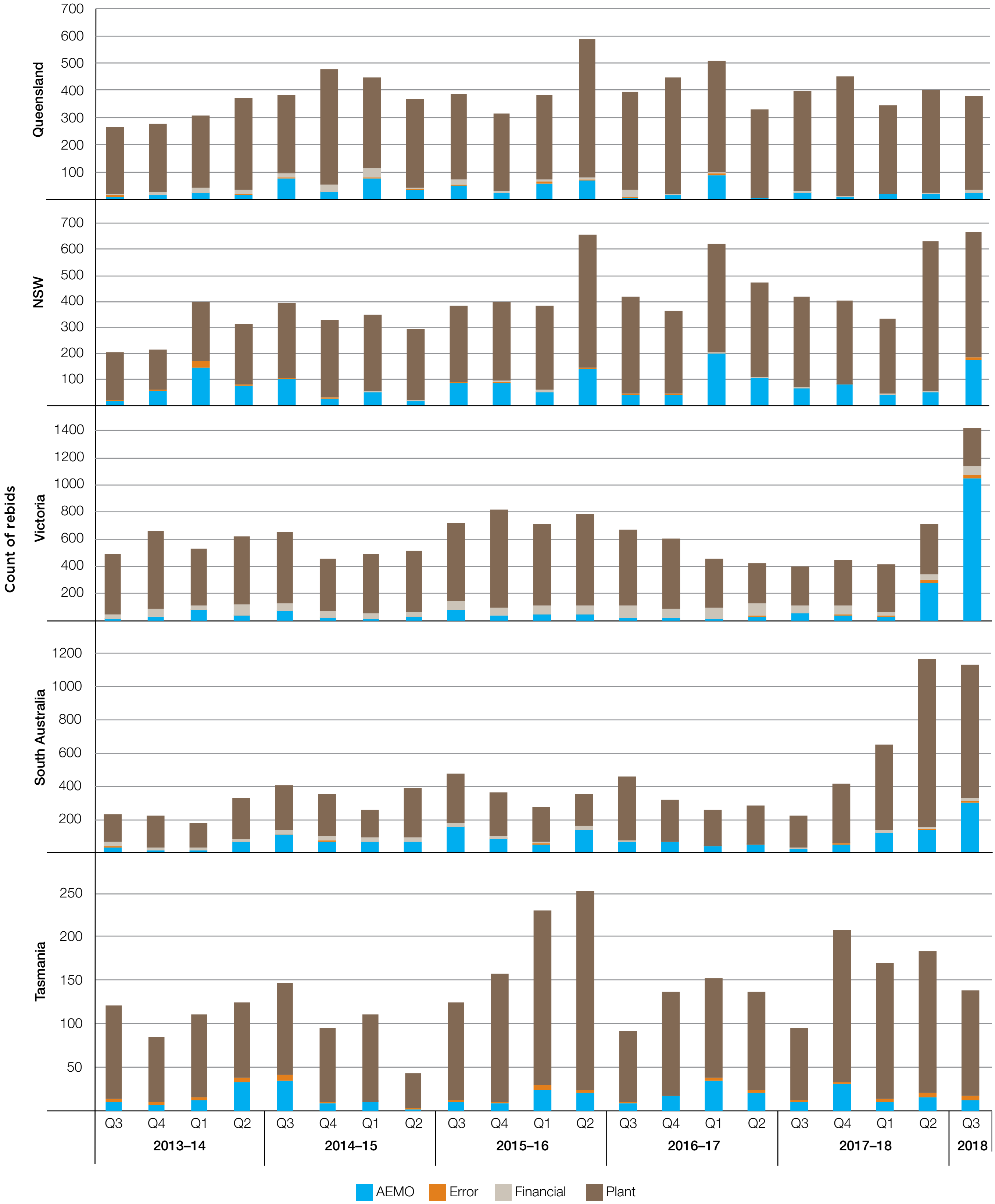

Source: AER.

**Figure A.2 Timing of late rebids for the NEM**




Source: AER.

**Figure A.3 Reasons for rebidding generation plant unavailable**




Source: AER.

### Figure A.4 FCAS reasons for $5000 prices in South Australia 2016–2018

| Date | Outage | Days of outage | Reason for high prices–rebidding, and or set up day ahead | Cumulative price threshold breach? | FCAS price | Energy price |
|---|---|---|---|---|---|---|
| 11, 12-Oct-15 | planned | 2 days | Planned Heywood interconnector outage. Rebidding of capacity from low to high prices by AGL Energy left less than 35 MW priced less than $5000/MW. | yes | Reached $13 100/MW for 92 consecutive dispatch intervals on 11 and 12 October (from 8.25pm 11/10/2015 to 4.00am 12/10/2015). Reached $12 400/MW for 38 consecutive dispatch intervals from 1.10pm to 4.15pm on 25 October. | Spot price remained below $250/MWh. |
| 25-Oct-15 | planned | 1 day | Planned Heywood interconnector outage. Rebidding of capacity from low to high prices by AGL Energy and Alinta Energy left less than 35 MW priced less than $5000/MW. | yes | Reached $12 400/MW for 38 consecutive dispatch intervals from 1.10pm to 4.15pm. | Spot price ranged between -$40/MWh–25/MWh during the affected period. |
| 1-Nov-15 | unplanned | 1 day | The Heywood interconnector failure was the primary factor for the high prices. There was no significant rebidding that contributed to the high FCAS prices in South Australia, because although a number of generators rebid after the separation, these rebids increased the amount of low priced FCAS capacity. | yes | Prices for all services were between $9000/MW and $13 800/MW for 8 consecutive dispatch intervals from 10.00pm to 10.35pm. | 10.30pm spot price reached $1821/MWh. |
| 26-Mar-16 | unplanned | 1 day | Unplanned outage of a circuit breaker at the South Morang Terminal Station. Only 10 MW of capacity was priced less than $5000/MW was offered (day ahead), for each of the regulation FCAS when the outage occurred. There was no significant rebidding. | no | Exceeded $12 400/MW for 7 consecutive dispatch intervals from 2.20am to 2.50am. | Approximately $65/MWh during this time |
| 11-Aug-16 | planned | 3 days | Planned network outage. Rebidding of 5 MW of capacity by Origin Energy in both regulation services into high price bands left only 34MW of capacity priced less than $5000/MW. | yes | Exceeded $10 000/MW for 107 (lower) and 92 (raise) 90 dispatch intervals from 10.35am to 7.25pm. | Ranged from $45–300/MWh during this time. |
| 1-Sep-16 | planned | 1 day | Planned network outage. Rebidding of 4 MW of capacity by AGL Energy in both regulation services into high price bands left only 34MW of capacity priced less than $5000/MW. | yes | Approximately $10 000/MW for 111 consecutive dispatch intervals from 7.25am to 4.35pm | Remained below $163/MWh during this time. |
| 16-Sep-16 | planned | 1 day | Planned network outage. Rebidding by Origin Energy in both regulation services into higher price bands left only 34MW of capacity priced less than $5000/MW. | no | Exceeded $9000/MW for 53 dispatch intervals (all dispatch intervals from 11.05am to 3.25pm and 5 dispatch intervals from 7.40am to 8.40am). | Ranged from $28–135/MWh during this time. |
| 18-Oct-16 | planned | 5 days | Planned outage on the Heywood interconnector and technical difficulties at Pelican Point (Engie) in the morning and Quarantine (Origin Energy) in the evening led to a reduction (rebidding) in low-priced services available. | no | Exceeded $11 000/MW (7.05am to 8.20am) and $12 000/MW (7.05pm to 10.45pm) for 61 dispatch intervals. | Remained below $111/MWh during this time. |
| 9-Nov-16 | planned | 2 days | Planned outage on the Heywood interconnector. Only 34 MW of capacity priced less than $5000/MW was offered (day ahead) from start of second day of the outage. | yes | Exceeded $6000/MW for 175 dispatch intervals (4.05 am to 6.35 pm). | Ranged from $45–110/MWh during this time. |
| 25-Nov-16 | planned | 4 days | Planned network outage. Only 34 MW of capacity priced less than $5000/MW was offered (day ahead) from start of fourth day of the outage. | yes | Exceeded $7900/MW for 91 dispatch intervals (4.05 am to 11.35 am). | Remained below $60/MWh during this time. |

| Date | Outage | Days of outage | Reason for high prices–rebidding, and or set up day ahead | Cumulative price threshold breach? | FCAS price | Energy price |
|---|---|---|---|---|---|---|
| 23-Jan-17 | unplanned | 1 day | Unplanned network outage. Only 30 MW of capacity priced less than $5000/MW was offered (day ahead) when the outage occurred. | no | Exceeded $13 000/MW for 7 dispatch intervals (approximately 5.20 am to 5.50 am). | 5.30 am spot price reached $2458/MWh. |
| 21-Mar-17 | planned | 1 day | Planned network outage. Rebidding by AGL Energy of 6MW in both regulation services left only 34 MW of capacity priced less than $5000/MW. | no | Exceeded $8990/MW for 65 dispatch intervals (11.05 am to 4.25 pm). | Ranged from $120–2400/ MWh during this time |
| 30-Mar-17 | planned | 2 days | Planned network outage. Rebidding by AGL Energy of 2MW left only 34 MW of capacity priced less than $5000/MW. | no | Exceeded $11 400/MW for 54 dispatch intervals (9.05 am to 1.30 pm). | Remained below $145/MWh during this time |
| 18-Apr-17 | unplanned | 1 day | Unplanned network outage. Less than 35 MW of capacity priced less than $5000/MW was offered (day ahead) when outage occurred. Origin Energy rebid in 10 MW at low prices. However AGL Energy then rebid 3 MW from low to higher prices, which leaves less than 35 MW of capacity prices less than $5000/MW. | yes | Exceeded $10 900/MW for 80 (lower) and 105 (raise) dispatch intervals (11.55 am to 8.35 pm). | Ranged from $80–150/MWh during this time |
| 22-May-17 | planned | 1 day | Planned network outage. Rebidding by Origin Energy replaced Quarantine's low priced capacity with Osborne. Due to different technical limitations at Osborne, less low priced capacity was actually available. | no | Exceeded $10 700/MW for 6 dispatch intervals (12.20 pm to 12.45 pm). | Around $60/MWh during this time |
| 28-Aug-17 | planned | 1 day | Planned network outage. Rebidding on 27/08/17 by AGL Energy at Torrens Island left only 33MW of capacity priced less than $5000/ MW offered for the day of the planned outage. | no | Reached or exceeded $10 000/MW for 102 consecutive dispatch intervals from 10.35am to 7.00pm. | Ranged from $200–$2500/MWh during this time |
| 14-Sep-17 | planned | 1 day | Planned network outage. Only 30 MW of capacity priced less than $5000/MW offered (day ahead) when outage occurred. | no | Reached or exceeded $10 900/MW for all dispatch intervals from 8.35am to 4.30pm. | Remained below $100/MWh during this time (with negative prices at 11.30am and 12pm). |
| 13 & 14-Oct-17 | planned | 2 days | Planned network outage. Only 33 MW of capacity priced less than $5000/MW was offered (day ahead) for both days of outage. Prices then decrease after AGL Energy makes more capacity at lower prices available. | no | Exceeded $9500/MW for all dispatch intervals (7:05am to 12.30pm (raise) and 7:05am to 11.30am (lower)) on 13 October and (6.05am to 9am (raise) and 6.05am to 8am (lower)) on 14 October. | Remained below $160/MWh during this time. |
| 24-Oct-17 | unplanned | 1 day | Unplanned network outage. Only 24 MW of lower regulation capacity priced less than $5000/MW was offered (day ahead). Rebidding of 16MW of raise regulation by AGL Energy at Torrens Island led to less than 35MW of capacity priced below $5000/MW from 6.40pm. | no | Exceeded $5000/MW for 23 (lower) and 26 (raise) dispatch intervals from 6.30pm to 8.30pm. | Remained below -$30/MWh during this time. |
| 8-Jul-18 | planned | 1 day | Planned network outage. Numerous times across the day Hornsdale Wind Farm 2 becomes stranded and unable to provide regulation services, due to special pricing arrangements that were in place as a result of market intervention by AEMO. | no | Exceeded $8000/MW for 25 (lower) and 28 (raise) dispatch intervals from 8am to 4.30pm. | Remained below $155/MWh during this time. |

Source: AER $5000 reports.