Wholesale electricity market performance report 2020

December 2020

AUSTRALIAN ENERGY REGULATOR

Australian Government

Inquiries about this publication should be addressed to:

Australian Energy Regulator
GPO Box 520
Melbourne VIC 3001

Tel: 1300 585 165

Email: aerinquiry@aer.gov.au

Contents

Executive Summary

Over the past year, National Electricity Market (NEM) prices have fallen from historic highs, driven by changes in fuel costs and other supply conditions.

The market is transitioning from a system dominated by large thermal generators to one that incorporates an increasing volume of widely dispersed renewable generators. Since our last report in 2018, this has continued with significant new entry of large-scale solar and wind generation and further adoption of grid scale batteries. In addition, our analysis suggests that while prices have fallen, they remain at levels sufficient to encourage further investment in new generation and storage.

This transformation has slightly lessened market concentration, as well as affected how participants offer their capacity, price signals for new investment, and markets for managing fluctuations in frequency. Flexible generation is becoming more important in firming fluctuations in intermittent renewable generation, and is now setting the price more often in the peak demand periods.

There are a range of other developments that could significantly impact the future direction of the NEM. There are concerns from governments that the market may not deliver sufficient new generation in an acceptable timeframe. As a result, Australian, state and territory governments are intervening in the market—through public sector investment in generation and by underwriting private investment. The existing market design is also being reconsidered. These changes could fundamentally alter the investment landscape. Adopting a common framework will best promote future investment and efficiency, and secure the best outcomes for consumers.

AER monitoring and reporting

The AER monitors and reports on the performance of the NEM under the National Electricity Law. We analyse and identify whether there is effective competition in the wholesale market and whether there are market features that may be detrimental to effective competition or the efficient functioning of the market.

This 2020 report is our second report covering all NEM regions. It presents a comprehensive picture of the state of wholesale competition in the NEM. It also analyses how the performance of the NEM has changed since our inaugural report released in 2018.

Market performance has changed considerably recently

Market outcomes have changed considerably in recent years. Average NEM prices have fallen and in 2019–20, annual prices were below $85 per megawatt hour in all regions for the first time since 2014–15.

A key driver of the lower prices was the increased amounts of low priced capacity on offer. Falling fuel input costs were reflected in lower priced offers by coal and some gas generators. At the same time, new entry of large-scale solar and wind generators provided additional low priced capacity which increased competitive pressure on incumbent plant.

In contrast, our 2018 report assessed the performance of the market in the context of historically high average NEM prices. These prices were largely driven by the exit of low cost coal-fired generation, culminating in the closure of Hazelwood power station in 2017, rising coal and gas fuel input costs and coal supply issues.

The transformation of the market is leading to the emergence of significant changes in intraday price and competition dynamics. Average prices were generally far lower in daytime hours, and there were a record number of negative prices, driven by increased penetration of low priced large-scale solar generation. In the evening peak, average prices tend to be higher. While there is significant amounts of low priced capacity offered in the evening peak, particularly by coal-fired generation, hydro generators are playing a far more important price setting role. This trend is likely to continue and the role of flexible generation, like hydro, and storage is likely to become more important.

Our review did not identify any concerning exercise of market power

There are elements of the NEM that make it vulnerable to the exercise of market power. The market is concentrated, with a few large participants controlling 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 is particularly the case in the evening peaks, highlighting the increasing importance of flexible capacity at these times. This concentration provides a number of participants with the potential to exercise market power. There has, however, been some lessening of market concentration since we last reported, with new entry from large-scale solar and wind generators reducing market concentration particularly in daylight hours.

While ownership in the market is concentrated, we have not identified a concerning exercise of market power by generators in this review. Importantly, as highlighted above, we have found that falls in input costs have been reflected in lower average generator offers, particularly by coal generators. Further, our analysis of recent short term price spikes over $5,000 per megawatt hour (MWh) has highlighted that these were generally driven by extreme weather and high demand. Concerning generator behaviour was not a major factor.

Our initial analysis of generator revenues and costs suggests that generators have been making positive earnings in recent years

We modelled the operating earnings of generators (as an indication of operating profits) in the mainland regions of the NEM for the first time. Our analysis showed that overall modelled operating earnings have been positive in recent years. These results, however, vary significantly from year to year depending on prevailing spot prices, generation technology and our assumptions regarding the level of contract cover.

Properly assessing operating earnings helps provide a stronger evidentiary basis for testing claims around the profitability of generators—be it that generators have been receiving excessive earnings or conversely that classes of generators are becoming uneconomic. Our initial assessment of operating earnings was undertaken using publicly available data and assumptions of likely contracting positions, and therefore may not reflect the actual position of individual generators. Participant information on revenues and costs will be required to get a more accurate picture of operating earnings.

There are ongoing signals to invest in the NEM

Supply and demand conditions have largely eased since our 2018 report. Looking forward, many large coal-fired power stations are expected to retire and more investment will be required to replace this capacity. Conditions are also still tight at times of high demand, so investment in flexible generation will be of particular importance.

Most new entry in recent years has been in wind and large-scale solar generation, supported by various renewable energy targets. The only generator to exit the market since our last report, Torrens Island A power station in South Australia, had already been replaced by new gas generation.

While prices have fallen recently, our modelling suggests they are still at a level to encourage new investment by a range of generation technologies. Signals for new entry for some technologies, particularly wind, large-scale solar and combined cycle gas turbine generators, have sustained since our last report. Our analysis also showed signals for new investment in storage technologies. These participants generally store energy when prices are low, and discharge when the price is high. In South Australia, Victoria and NSW, prices vary enough across the day for new entrant storage participants to recover their costs.

Potential barriers to entry and impediments to efficient price signalling

During our review, market participants identified a range of potential barriers to entry for new generation. 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.

There are prevailing features of the market that may act as a barrier to entry, particularly for some generation technologies. Investment in capital-intensive, long-lived assets requires some confidence over future prices. The risks of investing in these technologies are significant in an environment of uncertainty about future technology costs, an unclear path for the exit of large generators, and demand uncertainty (particularly for large loads).

However, a range of market participants highlighted concerns with government investment and intervention. Some participants argued that investment decisions of government owned businesses may not always be market driven. Snowy 2.0 was highlighted as a project that some participants thought may be influenced by non-commercial factors. Issues were also raised with the various schemes governments are putting in place to underwrite generation investment. While it was acknowledged that these schemes are designed to meet environmental, affordability or reliability objectives, it was argued that they potentially raise significant efficiency concerns. It was felt that increasingly new entry could be driven by incentives provided under these schemes.

The market for managing frequency fluctuations is becoming more competitive but participants are still driving prices high at times

Frequency control ancillary services (FCAS) markets were another area of key focus in this review. There has been increased attention on these markets recently, with a greater need for FCAS and fluctuating FCAS prices. Several new participants have entered in recent years which has reduced concentration in some markets. In South Australia in particular, new entrant batteries and demand response aggregators have competed against the incumbent participants, which has resulted in lower priced offers. But when power system requirements necessitate local participants to provide FCAS in South Australia, generator rebidding and a lack of low priced capacity can still drive high prices. We will continue to monitor competition in FCAS as these markets evolve and technology develops.

Where to from here?

While our review has made a range of observations about the state of competition in the NEM, it has also identified a number of areas where further work is required.

We will continue to monitor the performance of the wholesale market as it transitions, with an emphasis on how dynamics change across the day, investment trends and the evolution of FCAS markets. In particular, we will focus on the implications for competition and efficiency of increased penetration of intermittent renewable generation and the role of flexible generation particularly in evening peaks. We also intend to request information on revenues and costs from generators to further our assessment of operating earnings. We will monitor and report on how major policy reforms and interventions are changing competitive dynamics in the NEM.

Our review has been conducted in the context of fundamental change which could significantly impact the future direction of the NEM. A number of reform processes are attempting to address many of the issues we have identified. Recognising that governments will continue to pursue their policy objectives, to optimise efficiency as well as other objectives, it is desirable that there is a mechanism to embed these approaches in a common NEM-wide framework. The Energy Security Board's (ESB) *Post 2025 market design for the National Electricity Market* (NEM 2025) reforms present an opportunity to achieve this objective.

1. Monitoring the National Electricity Market

Key points

- The Australian Energy Regulator (AER) reports on whether there is effective competition in the wholesale electricity markets and identifies impediments to competition and efficiency.
- This is our second comprehensive report covering competition and efficiency in all regions in the National Electricity Market (NEM), following on from our initial report released in 2018.
- Our reports provide information and analysis that assists 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 to support efficient and competitive markets

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

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

We must report on the market at least every 2 years. From this, we may also advise the Australian and state governments on market performance and identify whether legislative or regulatory reform is required.

This 2020 report is our second report presenting a comprehensive picture of competition in the NEM, covering all NEM regions. Since 2019 we have published quarterly reports providing timely and comprehensive updates on the performance of the NEM.[1] This report extends that analysis and examines the performance of the NEM in more detail. In addition, we also have other performance reporting obligations across our wholesale, retail and network areas. For wholesale, many of our other functions 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. Through our monitoring and reporting, we assist 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.

1 AER, *Performance reporting*, AER website.

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 of the range 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 occurs 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 to which we must have regard:[2]

- 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. Conversely, if demand decreases relative to supply, there is downward pressure on prices, which should prompt higher cost generators to exit the market. Contract markets also act in conjunction with spot markets as a price risk management tool as well as a longer term signal for investment. 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 3 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 enabling innovation and having the right mix of demand and supply side options to provide maximum output at minimum cost over time.

2 National Electricity Law Section 18B.

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

As required under the NEL, we used a range of publicly available information in the first instance, including information and data published by the Australian Energy Market Operator (AEMO), the Australian Energy Market Commission (AEMC) and the Australian Securities Exchange (ASX). We also considered reviews or inquiries by other agencies where relevant.

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

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

In 2020 we have applied the same approach as our 2018 report, using a structure-conduct-performance framework to analyse the market and focusing on effective competition and efficiency. In broad terms:

- 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—2020 focus* provide detail on this framework and the areas we identified for focus in 2020. We also published the *Wholesale electricity market performance report 2020—Methods and assumptions*, the *Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach*, *limitations and results*, and the *Wholesale electricity market performance report 2020—Generator operating earnings approach and limitations* which sets out more detail on the calculations and methods we applied in this report.

1.3.2 We have expanded our analysis in this report

Building on the work in our 2018 report, in 2020 we have expanded our analysis in several areas to inform our assessment of the performance of the market. This includes:

- Investigating how market dynamics and participant behaviour change across the day, including examining shifts in demand, pricing, generation and market concentration.
- Modelling operating earnings of incumbent generators using publicly available data.
- Modelling the cost of potential new entry for a range of storage technologies to determine whether the spot price is sufficient to support investment.
- Expanding our analysis of frequency control ancillary services (FCAS) markets to include an assessment of structure—conduct—performance for these markets.

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 recent trends in generator operating earnings.
- Chapter 6—the prospects for new investment.
- Chapter 7—barriers to entry and efficient price signalling.
- Chapter 8—understanding competition in FCAS markets.
- Chapter 9—key challenges facing the NEM.

2. Market conditions and change drivers

Key points

- After reaching record highs in some regions, prices in the National Electricity Market (NEM) are significantly lower than they were 2 years ago. This has largely been driven by changes in supply conditions, particularly falls in coal and gas fuel input costs, as well as further new entry of low cost large-scale solar and wind generation into the market.
- The significant transformation underway continues to change the market dynamics. The generation mix is shifting and new markets and products are emerging. Fast response, flexible generators, demand management and storage are becoming more significant, and their role is likely to continue to grow in future.
- Rooftop and large-scale solar penetration is changing intraday dynamics, with demand, generation and price becoming more variable throughout the day.
- The prices of frequency control ancillary services (FCAS) have increased, driven by the changing technology mix and bidding behaviour.
- The COVID-19 pandemic has been a factor in 2020 outcomes, impacting maintenance schedules, consumer demand and fuel input costs.

Electricity generated in eastern and southern Australia is traded through the NEM. The NEM is a wholesale spot market, in which fluctuations in supply and demand determine the price of electricity (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 participant behaviour and price movements. Understanding these factors can also help determine whether current market conditions will persist.

The market is transforming as the generation mix transitions to intermittent sources with lower emissions, and technology changes market interactions. The move to large-scale renewables has resulted in flexible output becoming more important to firm that generation, the growth of distributed energy resources through micro generation rooftop solar is impacting the levels of demand served by the electricity grid, and smarter technologies are changing how both generators and consumers interact with the market.

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

- Section 2.1 summarises spot electricity price outcomes over the past 5 years.
- Section 2.2 provides an overview of the current NEM transformation and its challenges.
- Section 2.3 highlights the fall in average prices and the increase in negative prices.
- Section 2.4 outlines the changes in supply conditions that contributed to recent price falls.
- Section 2.5 explores the changing intraday dynamics in the market resulting from the penetration of solar generation.
- Section 2.6 highlights the increased prices associated with managing system frequency.
- Section 2.7 outlines some of the impacts of COVID-19 on the NEM.

Box 2.1 The NEM

The National Electricity Market (NEM) is a wholesale spot market for trading electricity. The market covers 5 regions—Queensland, NSW (including the ACT), 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 190 large power stations (comprising around 280 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 large-scale solar farms. There are also 8 batteries and pumped hydro power stations that can store energy for later use. Electricity generated by rooftop solar photovoltaic systems is not traded through the NEM, but does impact demand.

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 (-$1,000 per MWh (megawatt hour)) and the price cap ($15,000 per MWh). The highest priced offer needed to meet demand sets the price every 5 minutes (dispatch price). Every 30 minutes, the 6 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 2 parties (known as over-the-counter) which lock in future electricity prices. 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.

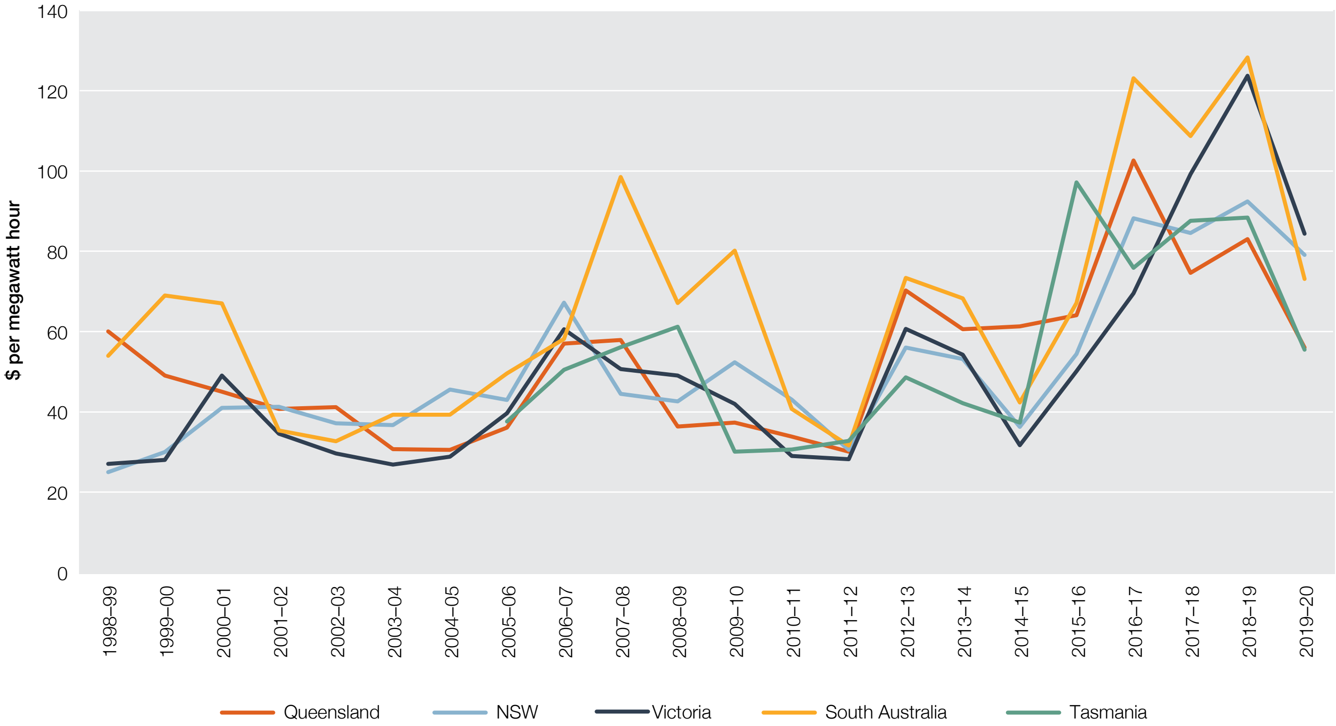
2.1 Average annual wholesale prices eased from record levels

The past 5 years have seen significant fluctuations in average volume weighted annual wholesale prices (figure 2.1). Over this period all regions have seen their highest annual average prices since the NEM started 20 years ago, with record or near record prices from 2016–17 to 2018–19. However over 2019–20 prices have fallen significantly as the generation mix has shifted to incorporate more renewable generation and fuel input costs have fallen.

- In 2015–16, average annual prices rose in every NEM region, increasing by around 50% to 60% in Victoria, NSW and South Australia, and 160% in Tasmania.
- In 2016–17, prices rose even more sharply, reaching record average annual prices in all regions, except Tasmania. Prices increased by around 60% to 85% in South Australia, NSW and Queensland, and 40% in Victoria. In South Australia, average annual prices reached a record high of $123 per megawatt hour (MWh).
- In 2017–18, prices eased in most states but remained close to record levels. Despite a 12% fall, the average 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 average price in Queensland became the lowest in the NEM after falling almost 30%.
- In 2018–19, prices increased again across all regions but most significantly in Victoria and South Australia as a result of high temperatures and a series of generator outages over summer. In these regions annual average prices rose 25% and 18%, to reach new records at $124 and $128 per MWh respectively—the highest in any region since the market started. Prices in Queensland and NSW rose around 10%, and NSW also saw record annual average prices at $92 per MWh.

- In 2019–20, average annual prices fell considerably in every region. Prices fell by around 30% to 40% in South Australia, Tasmania, Queensland and Victoria, and by 14% in NSW. Across the NEM as a whole, 2019–20 marked the first time since 2014–15 that average annual prices were below $85 per MWh in all regions. In 2019–20 Tasmania became the lowest priced region, followed by Queensland which had its lowest prices since 2011–12.

Figure 2.1 Annual volume weighted average prices in the National Electricity Market



Source: AER analysis using NEM data.

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.

The performance of the wholesale market can have a significant impact on retail prices and electricity bills, though it can be difficult to measure the extent of that impact (box 2.2).

Box 2.2 How the wholesale market affects retail bills

A typical retail electricity bill includes wholesale costs of buying electricity in spot and hedge markets, network costs for transporting electricity, costs relating to environmental and regulatory schemes, and retailer costs and margins. Wholesale costs average around 35% of a residential electricity bill.[3]

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 on, for example, how exposed individual retailers are to the spot price, how they structured their portfolios and when their contracts were entered into or expire.

3 ACCC, *Inquiry into the National Electricity Market—November 2019 Report*, 22 December 2019, p. 4.

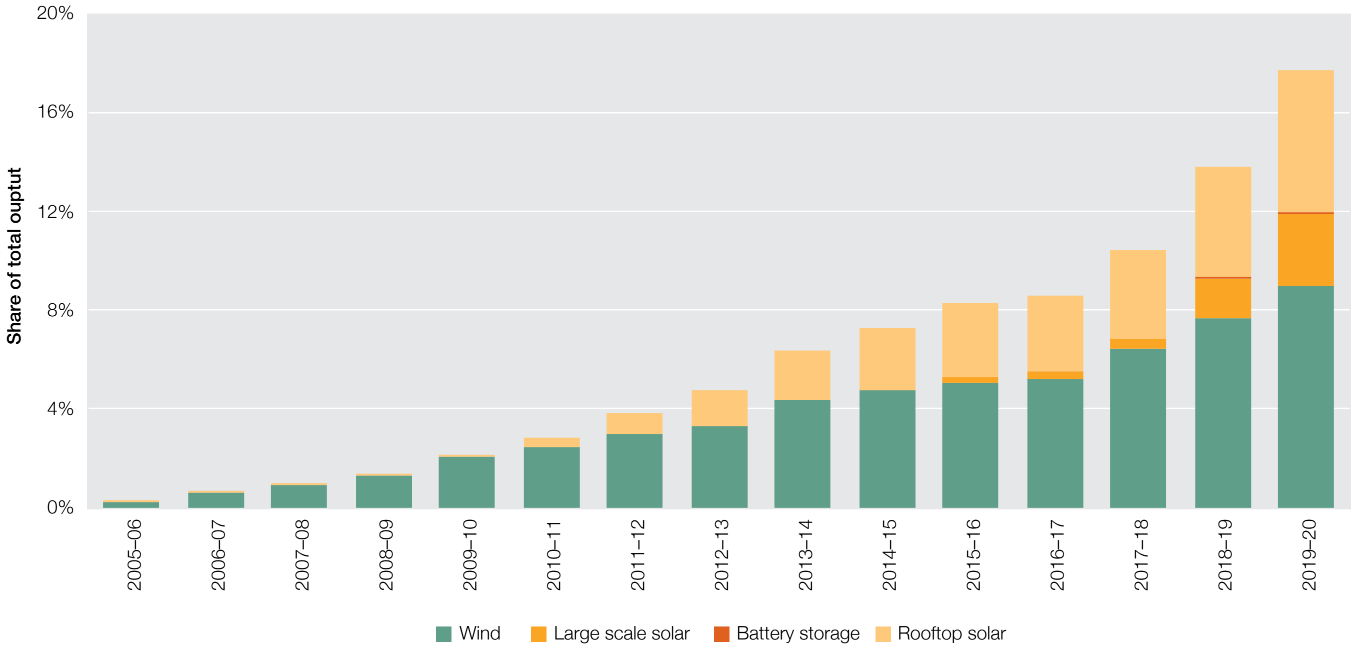
2.2 The market continues to transform

The NEM is transitioning to a lower emissions generation mix. This transition has accelerated since our 2018 report, and is expected to continue with further penetration of both renewable generation and storage technologies, as well as the exit of significant coal-fired generation. Fast response flexible generators and storage are becoming more important as intermittent generation continues to connect to the grid.

2.2.1 Coal remains the prevailing fuel source, but the share of renewables is growing

Since our last report, generation from renewable sources has continued to rise rapidly, and is becoming a significant part of the overall generation mix (figure 2.2). There is still significant investment in renewables on the horizon, with renewable generation accounting for all committed investments in the NEM (section 6.1.1).

Figure 2.2 Battery, wind and solar generation share of total output



Source: AER analysis using NEM data.

Note: Sum of generation as share of total output by financial year.

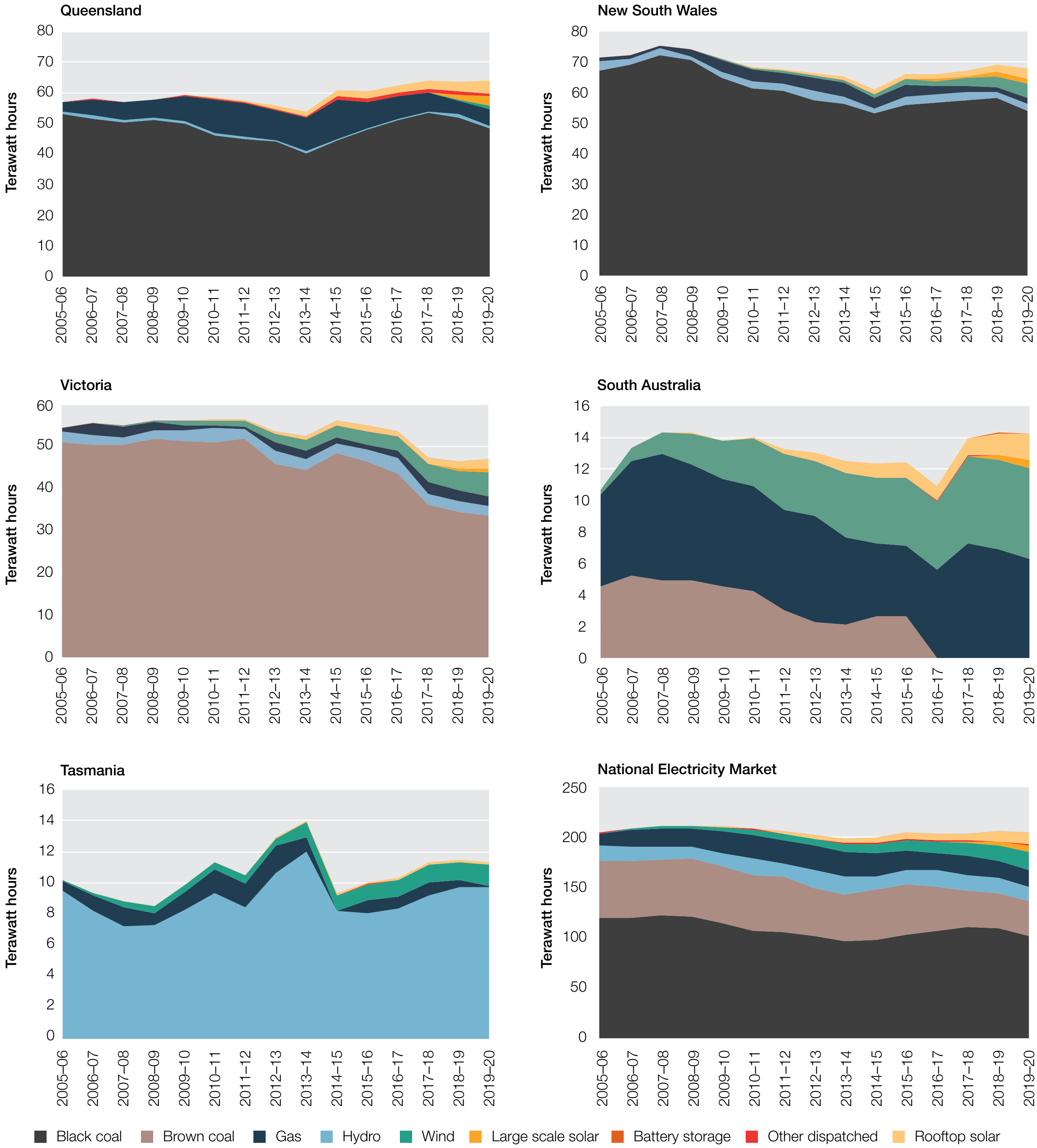
Generation from wind rose to contribute 9% of total output in the NEM in 2019–20, up from 6% in 2017–18, as around 2,600 megawatts (MW) of new capacity entered the market. Wind penetration continues to be strongest in South Australia, meeting around 41% of the state's electricity requirements in 2019–20. Significant investment in new wind generation is continuing, with 8 wind projects (around 1,700 MW) expected to be commissioned by the end of 2020–21.

Solar technologies have also rapidly become an important source of generation in the NEM. Large-scale solar generation has grown from less than 1% of total output in 2017–18 to meeting around 3% of the NEM's electricity requirements in 2019–20. From 2017–18 around 3,400 MW of large-scale solar capacity has entered the NEM, half of which has been in Queensland. As a result Queensland has the highest penetration of large-scale solar generation, with around 5% of output provided by large-scale solar in 2019–20. This has particularly affected the generation mix and shaped prices in the middle of the day (section 2.5). Another 8 projects (over 900 MW) are expected to be commissioned across NSW, Victoria and Queensland by the end of 2020–21 (section 6.1.1).

Household rooftop solar continues to impact market outcomes. Although rooftop solar is not dispatched in the wholesale market, it reduces the demand that must be met by generation from the grid. The output of rooftop solar systems has increased significantly since our last report, now meeting almost 6% of the NEM's electricity requirements, up from 3.6% in 2017–18. Rooftop solar penetration continues to be highest in South Australia, where it met almost 12% of the state's electricity needs, and has grown rapidly in Queensland where it supplied around 7% of electricity requirements in 2019–20. Rooftop solar is continuing to change the distribution of grid demand throughout the day (section 2.5.1).

Coal remains the dominant fuel source in Queensland, NSW and Victoria (figure 2.3). But in recent years significant coal-fired capacity has retired from the market with further closures planned in the future (section 6.1.2). In 2019–20 coal accounted for around 38% of capacity (down from 41% in 2017–18) and supplied 67% of output (down from 73%) in the NEM.

Figure 2.3 Generation output by fuel type



Source: AER analysis using NEM data.

Note: Sum of generation by financial year. Other dispatched includes generation from bagasse, biomass, diesel, liquid, and waste gas fuels.

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

With the growth in intermittent renewables and the retirement of thermal generation, generation that can effectively match the variation in intermittent supply is likely to play an increasingly significant role in the market. These fast start flexible technologies include storage (such as batteries) and generation (such as fast start gas and hydroelectricity) that is flexible in its ability to start and stop quickly, or ramp up and down quickly at low cost. Flexible capacity currently makes up around 30% (15,200 MW) of total capacity in the NEM.

The retirement of aging thermal generation also has implications for power system security. In addition to providing energy, thermal generators can supply a number of security services such as inertia, system strength and voltage control. Traditionally, these services have been provided as a by-product of energy production.

Energy storage is expected to play an increasingly significant role in Australia's energy supply mix, because as well as firming variable production with demand, it also contributes to power system security. Since 2017–18 over 260 MW of batteries have entered in South Australia and Victoria and are having a significant impact on FCAS markets (section 8.2). Large-scale storage is also being considered through various pumped hydro projects. These projects allow hydro generation plant to overcome limited water supplies. 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 or to provide system security services. The rise of intermittent generation could provide new opportunities to deploy this form of energy storage at a larger scale. In particular, pumped hydro forms the basis of the 'Snowy 2.0' (2,000 MW) and 'Battery of the Nation' (2,500 MW) proposals in NSW and Tasmania.

Wind and large-scale solar generation is unable to provide many power system security services. As most new entry is in these technologies, additional measures are required to ensure the provision of these services. For example, participants are installing synchronous condensers in South Australia in order to provide system strength and inertia services, and some battery sites are now trialling providing synthetic inertia.[4] [5] There is also increasing consumer participation being enabled by advanced metering, solar, battery and other technologies. Given the change underway, it is increasingly important that the NEM market design provides efficient price signals for operation and investment decisions. There are reforms underway to align financial incentives with physical operation to more accurately reward those who can deliver supply or demand side responses when they are needed by the power system (section 9.3).

Demand management technologies may change how consumers interact with the market and support some aspects of power system security and reliability. A wholesale demand response mechanism will enable consumers to sell demand response in the wholesale market either directly or through specialist aggregators from October 2021.[6] To date there has been limited market-based demand response in energy, but some uptake in FCAS markets (section 3.7).

In contract markets, participants are responding to the increased penetration of intermittent renewable generation and the changing grid demand profile by offering financial 'firming products'. Providers of these products typically control flexible generation that can complement an intermittent generation profile. Products such as solar shape or super peak contracts may assist participants with managing the increased price risk posed by more volatile prices driven by more renewable generation in the mix.[7] While generators have offered similar products for some time, more participants are now expressing interest. A significant development in access to these products was the launch of the Renewable Energy Hub in 2019, designed to develop and host new hedge contracts for clean energy technologies, backed by the Australian Renewable Energy Agency (ARENA).[8] 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.

4 ElectraNet, *Installation of synchronous condensers*, information sheet, August 2019.

5 Australian Renewable Energy Agency (ARENA), *Hornsdale Power Reserve Upgrade*, ARENA website.

6 AEMC, *Wholesale demand response mechanism—Final report*, rule change, 11 June 2020.

7 In the over the counter market new standardised products are emerging to firm renewable capacity and manage changing peak demand. The 'super peak' contract covers the morning and evening periods when demand is high but wind or solar generation is low. Solar and inverse solar shaped products follow the shape of a solar generation profile or the inverse. Combined, the solar and inverse solar products create a flat swap contract. For more detail, see *Renewable Energy Hub*.

8 TFS Green, *Renewable Energy Hub*.

Five minute settlement, which aligns price signals with physical dispatch of generation instead of averaging prices over a 30 minute trading interval, is scheduled to be implemented in October 2021.[9] This change in market design may provide stronger price signals for fast response generation, and may impact behaviour, contracting strategies and incentives of incumbent generation.

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

2.3 Lower priced trading intervals are driving lower average prices across the NEM

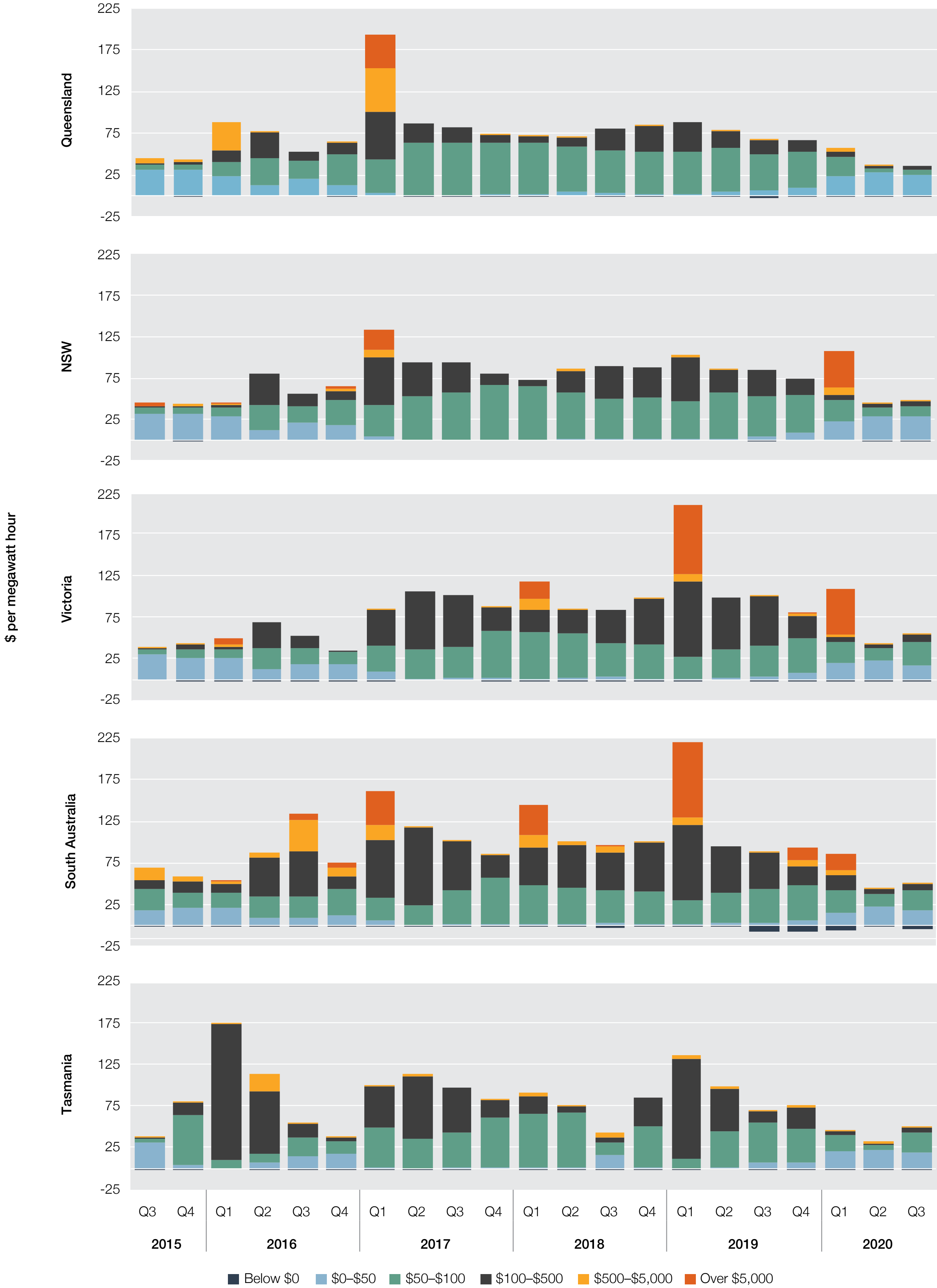
Average prices can be driven by a general movement in prices or a more limited number of extreme price events. Historically in the NEM, high average prices were driven by a few extreme price events. However, following the exit of Hazelwood power station and the emergence of coal supply issues and increases in fuel costs, there was a general uplift in prices between 2016–17 and 2018–19 (figure 2.4).

Reversing the trend we observed in our 2018 report, there are now many more trading intervals priced less than $50 per MWh, and these are playing a significant role in driving overall market price outcomes. From the second half of 2019, across all regions there has been a growing contribution from prices in the $0 to $50 per MWh price range and a fall in the contribution of prices over $50 per MWh. This was due to fuel costs easing and more renewable generation entering the market. In South Australia the increasing incidence of negative prices is also beginning to contribute to lower overall average prices.

Prices over $5,000 per MWh can still have a significant impact on overall outcomes. In Victoria and South Australia, high prices driven by extreme weather in Q1 2019 led to record high average quarterly and annual prices (section 2.1). But even in generally mild conditions, these events can still affect average prices. In Q1 2020, prices over $5,000 per MWh contributed $43 and $54 per MWh to the average quarterly price in NSW and Victoria.

9 AEMC, *Five minute settlement—Final determination*, rule change, 28 November 2017.

Figure 2.4 Contribution of different price bands to quarterly wholesale prices

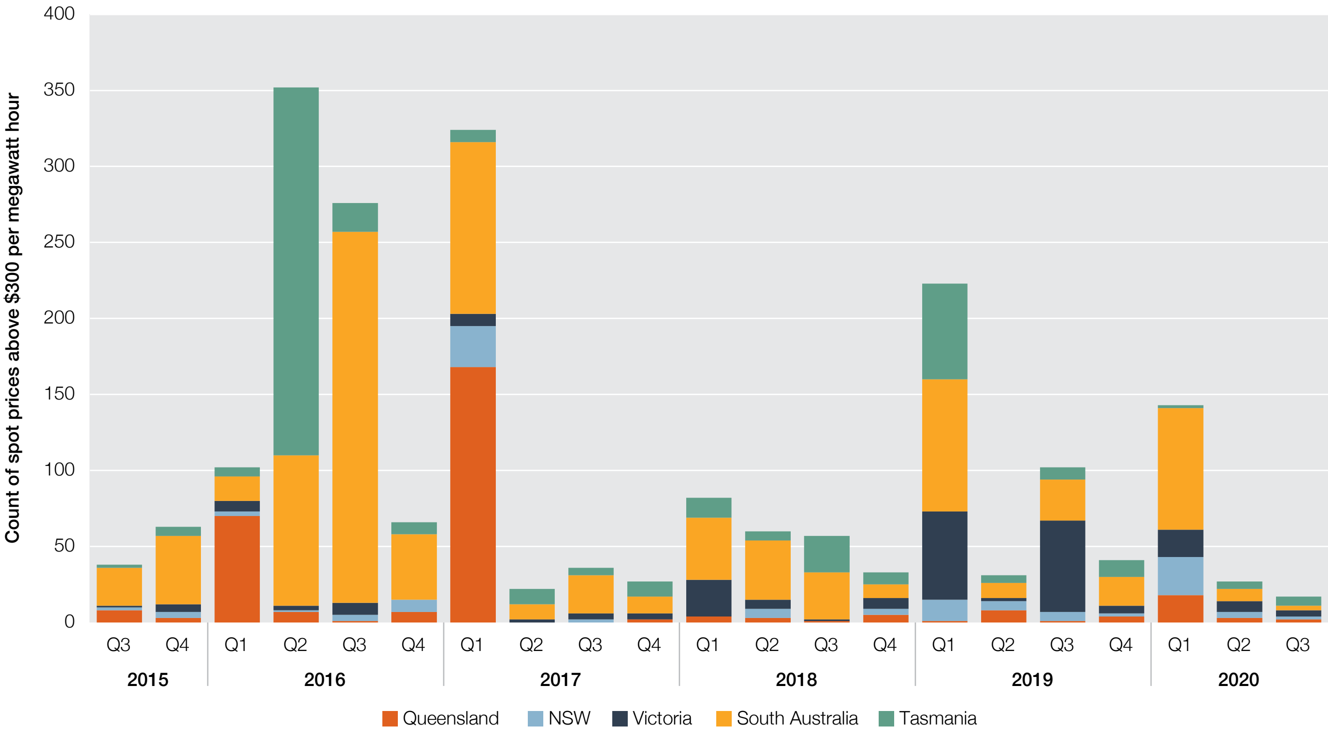


Source: AER analysis using NEM data.

Note: Shows the extent to which different spot prices within defined bands contributed to the volume weighted average wholesale prices in each region.

Short-term price spikes can be the result of a variety of factors, such as extreme weather, technical faults and generator rebidding. In 2015–16 there were 555 instances of the half hour spot price exceeding $300 per MWh, rising to 688 in 2016–17 (figure 2.5). After Hazelwood's exit, in 2017–18 there were only 205 occasions of prices over $300 per MWh, rising to 344 occasions in 2018–19. More recently average prices have come down, and the number of extreme price events has stayed low. The spot price exceeded $300 per MWh on only 313 occasions in 2019–20.

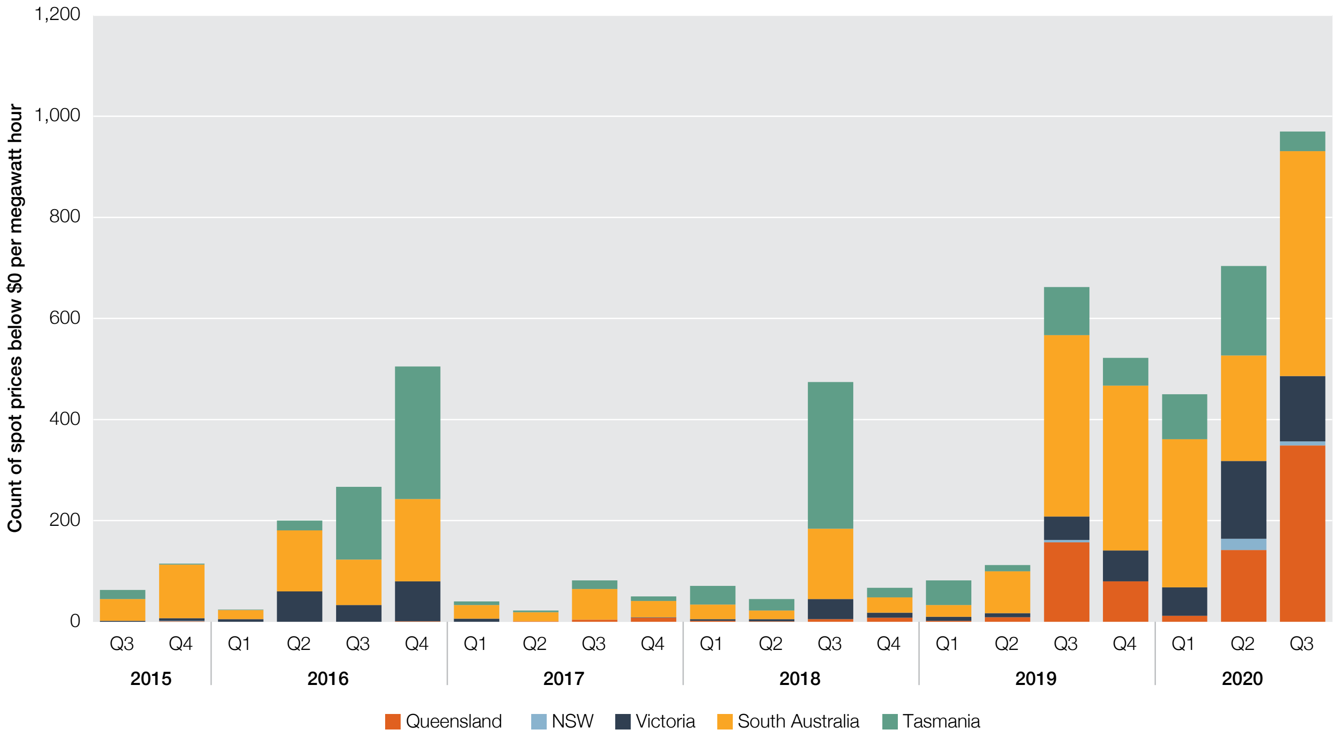
Figure 2.5 Spot prices above $300 per MWh



Source: AER analysis using NEM data.

In 2019–20 we observed a significant increase in negative prices (figure 2.6). There were 2,338 trading intervals where prices were below $0 per MWh, almost 3 times the previous high of 834 in 2016–17. In 2019–20, half of all negative prices occurred in South Australia, the state with the highest wind and solar penetration. In this region negative prices are beginning to contribute to lower average prices, with 51% of the instances of negative prices occurring below -$50 per MWh, and 35% below -$100 per MWh. The majority of the prices below -$100 per MWh were not forecast (section 4.3.1). Historically across all regions lower demand quarters (Q3 and Q4) have seen the most instances of negative prices, but there were at least 450 instances in every quarter of 2019–20.

Figure 2.6 Spot prices below $0 per MWh



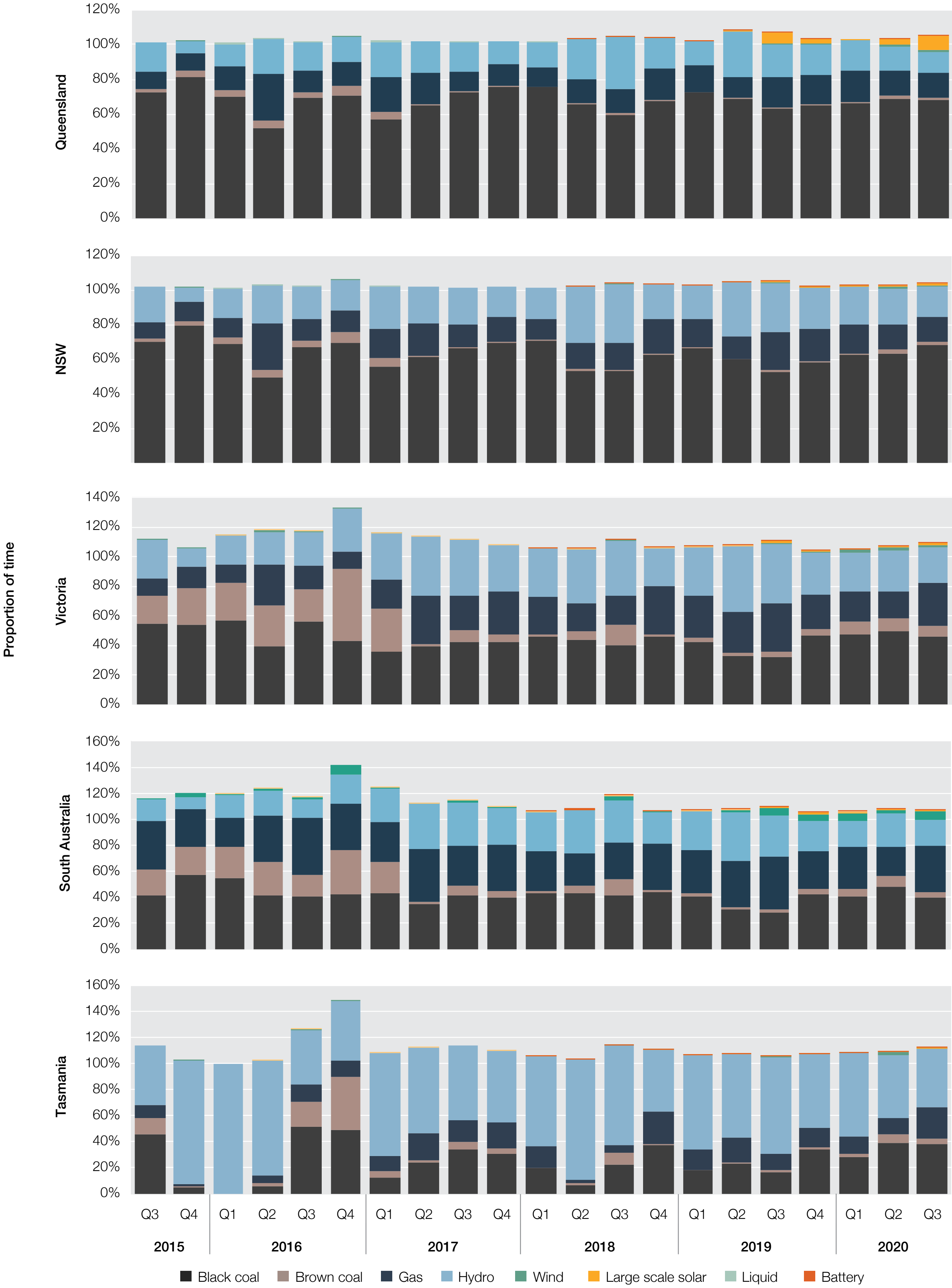
Source: AER analysis using NEM data.

2.4 Changes in supply conditions have contributed to the recent falls 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 contributed significantly to the falls in prices in 2019–20, as well as the sustained uplift in prices which preceded them. Since our 2018 report, the primary changes in supply conditions have been falling gas and black coal fuel costs, as well as the continued new entry of wind and large-scale solar generation. Lower demand for electricity from the grid, due to increased rooftop solar output, has also contributed to lower prices, but to a lesser extent than supply side factors.

After the Hazelwood power station closed in March 2017, a large amount of low cost fuel capacity exited the market. This meant that higher cost generation was needed to meet demand, and thus set the price more frequently (box 2.1 discusses how prices are set in the NEM). Since Hazelwood closed, the percentage of time that the comparatively lower fuel cost brown coal generation set the price in Victoria fell significantly, and it hasn't set the price more than 13% of the time since then (figure 2.7). However, since mid-2019 low cost renewables like wind and large-scale solar are starting to set the price more often in Queensland and South Australia, most often in the middle of the day (section 4.3.4). At the same time, black coal has been setting the price more often across all states due to a combination of lower demand and lower fuel costs.

Figure 2.7 Price setter by fuel type and region



Source: AER analysis using NEM data.

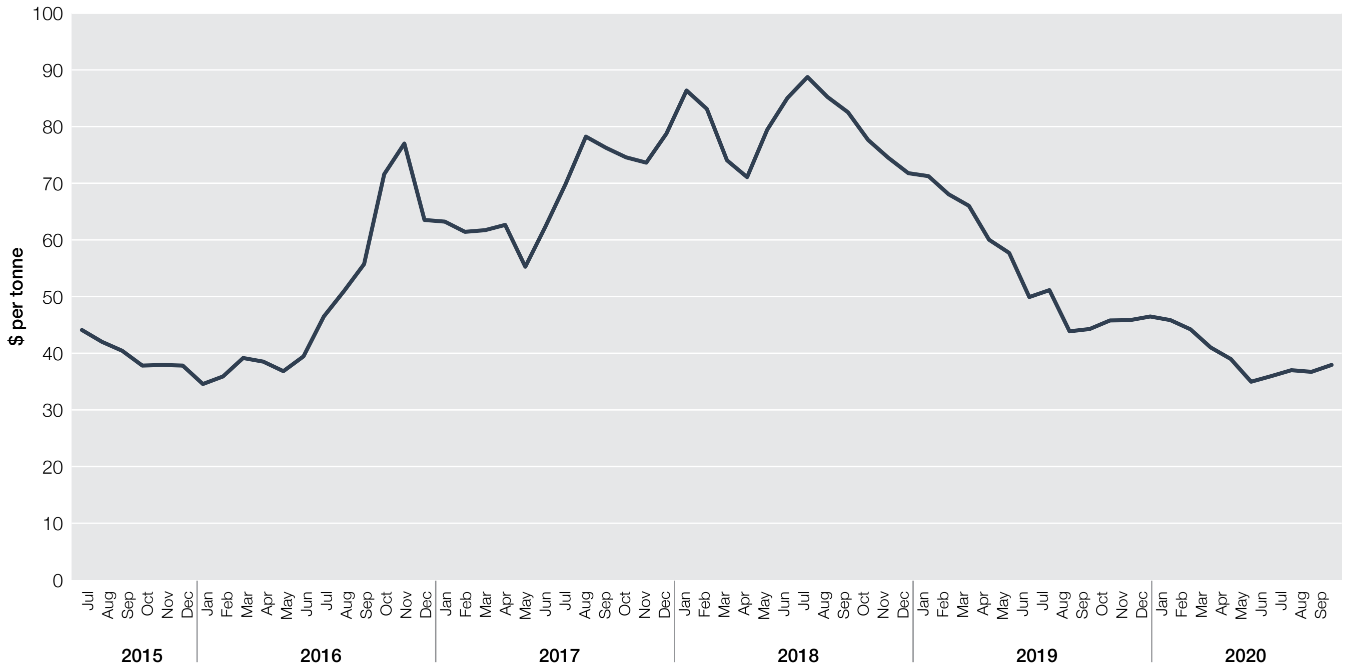
Note: Figures show more than 100% because the price can be set by more than one generator or fuel type at a time.

2.4.1 Lower gas and black coal fuel costs have contributed to lower offers

Spot prices for both coal and gas have fallen significantly over 2019 and 2020, and this has contributed to black coal and gas generators offering more low priced capacity into the wholesale market (section 4.1).

Coal generators can source their fuel from a range of sources including directly and relatively cheaply from an attached mine, or through short or long term fuel contracts which bring coal in from further afield. Much of the coal used by NSW black coal generators is sourced through these coal supply contracts. Short-term supply contracts for coal are likely to align more closely with the prevailing international coal price. Generators may also be exposed to changes in the international coal price if long term contract negotiations coincide with fluctuating coal prices. For this reason, the price of coal at the Newcastle port is often used as a reference point for coal fuel costs, and this has more than halved since mid-2018 (figure 2.8).

Figure 2.8 Newcastle thermal coal index



Source: AER analysis using data from globalCOAL.

Note: The Newcastle price index (NEWC Index) is a reference price for spot thermal coal at the Newcastle Port in NSW. It is derived from the Newcastle coal index (USD$ per tonne), converted to AUD$ per tonne with the Reserve Bank of Australia exchange rate.

In our 2018 report, we reported that higher priced offers from NSW black coal generators was the result of increasing fuel input costs as well as fuel supply issues. However, our report also highlighted concerns that these higher priced offers may not have been fully explained by these issues, and that a lack of competition may have also contributed to higher priced offers. This concern was also echoed when Queensland black coal generators, who were not facing the same issues of their NSW counterparts, began offering at higher prices.

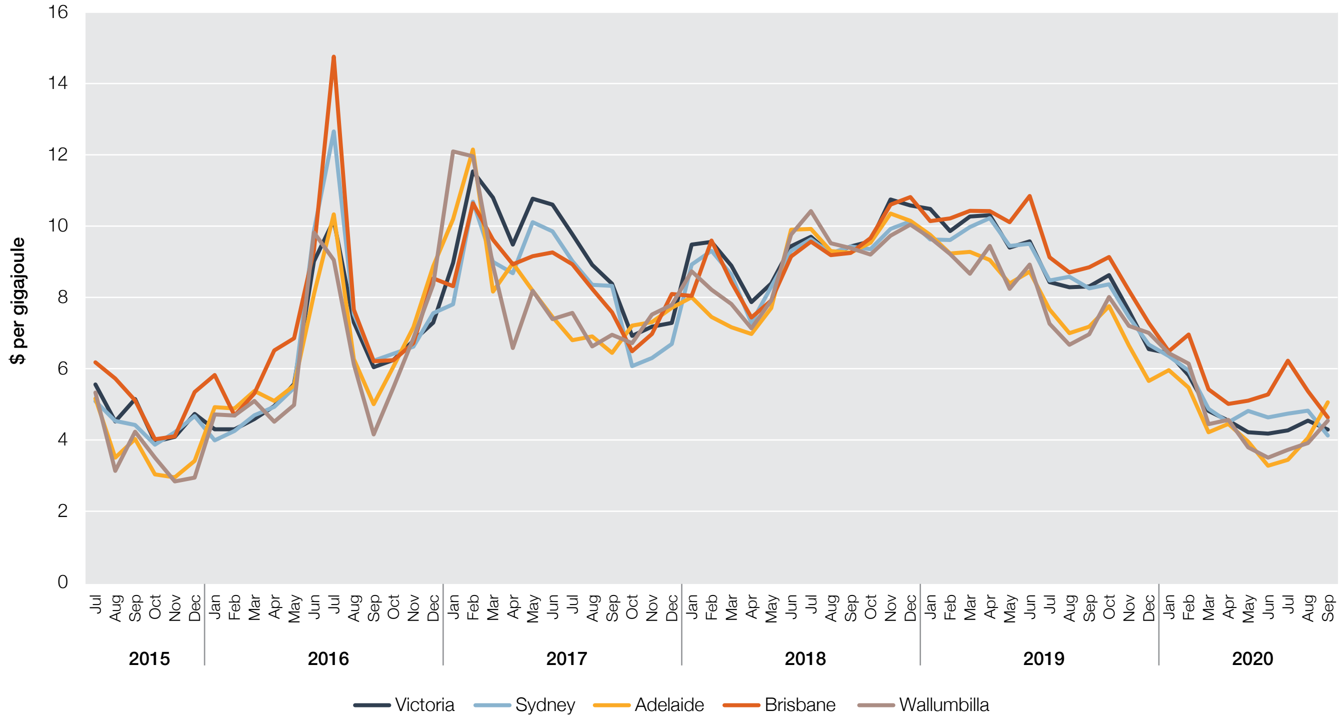
Since then, we have observed these participants' offers come down to lower prices, and decreasing proxy fuel input costs have been a contributing factor (section 4.1). In addition, participants have indicated that the previously reported fuel supply issues have improved. However, a lack of competitive constraint may still be allowing Queensland black coal generators to shadow the price set by their NSW counterparts (section 4.1.2).

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 Gas Supply Hubs at Wallumbilla and Moomba. Gas prices in these markets more than halved since the beginning of 2018 (figure 2.9). The decrease in gas prices was largely due to the weak international oil prices, ongoing excess global LNG supply and COVID-19 containment measures reducing international demand.[10] However these issues are expected to resolve over the next 2 years.[11]

10 AER, *Wholesale markets quarterly—Q2 2020*, 14 August 2020, pp. 37–38.

11 Department of Industry, Science, Energy and Resources (DISER), *Resources and energy quarterly September 2020*, September 2020 p. 67.

Figure 2.9 Spot market gas prices



Source: AER analysis using gas market data.

Note: 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 that trading occurred. The Moomba hub has not been included as it sees very few trades.

2.5 Solar penetration is impacting demand, the generation mix and prices throughout the day

The rapid growth of both rooftop and large-scale solar has shifted intraday supply and demand patterns for electricity from the grid, and thus wholesale prices.

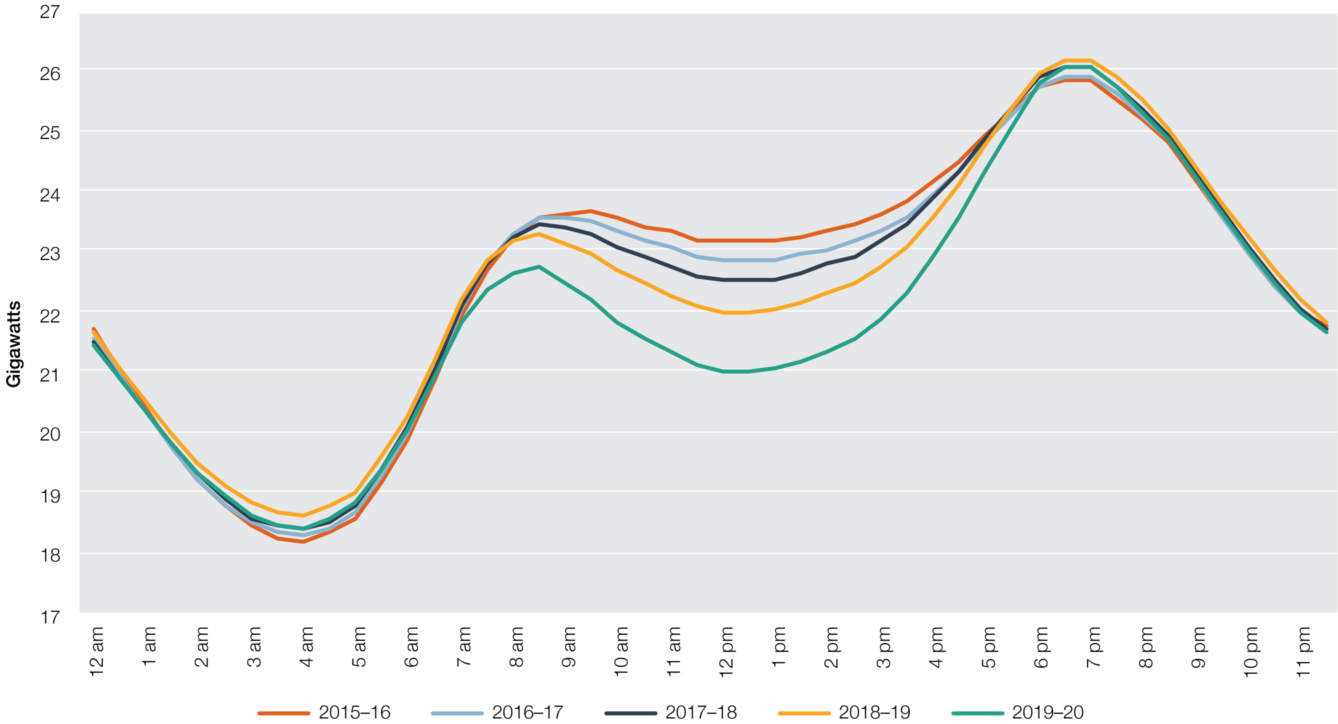
2.5.1 Growing rooftop solar output is reducing demand for grid generation in the middle of the day

The way users consume energy has not changed significantly over time. Generally demand begins to pick up in the morning and remains constant during the day, before hitting its peak at sundown and tapering off during the night. However as more rooftop solar has been installed, many households and businesses have become self-sufficient during the day or may even export power, meaning that they do not need to draw electricity from the grid.

This penetration of rooftop solar has led to a reduction in demand for grid-sourced electricity generation in the middle of the day, while demand has stayed relatively unchanged in the evening peak (figure 2.10). This fall has been particularly prominent in 2019–20 coinciding with a large increase in rooftop solar output and resulting in record low demand in some regions.[12]

12 AER, *Wholesale markets quarterly–Q3 2020*, 12 November 2020, pp. 15–16.

Figure 2.10 Average NEM native demand by time of day



Source: AER analysis using NEM data.

Note: Volume weighted average price is weighted against native demand in each region, and averaged for all hours in the year. AER defines native demand as the sum of initial supply and total intermittent generation in a region. Figure presents outcomes in NEM time (i.e. Australian Eastern Standard Time). Values of y-axis do not start at zero in order to emphasise the changes in demand.

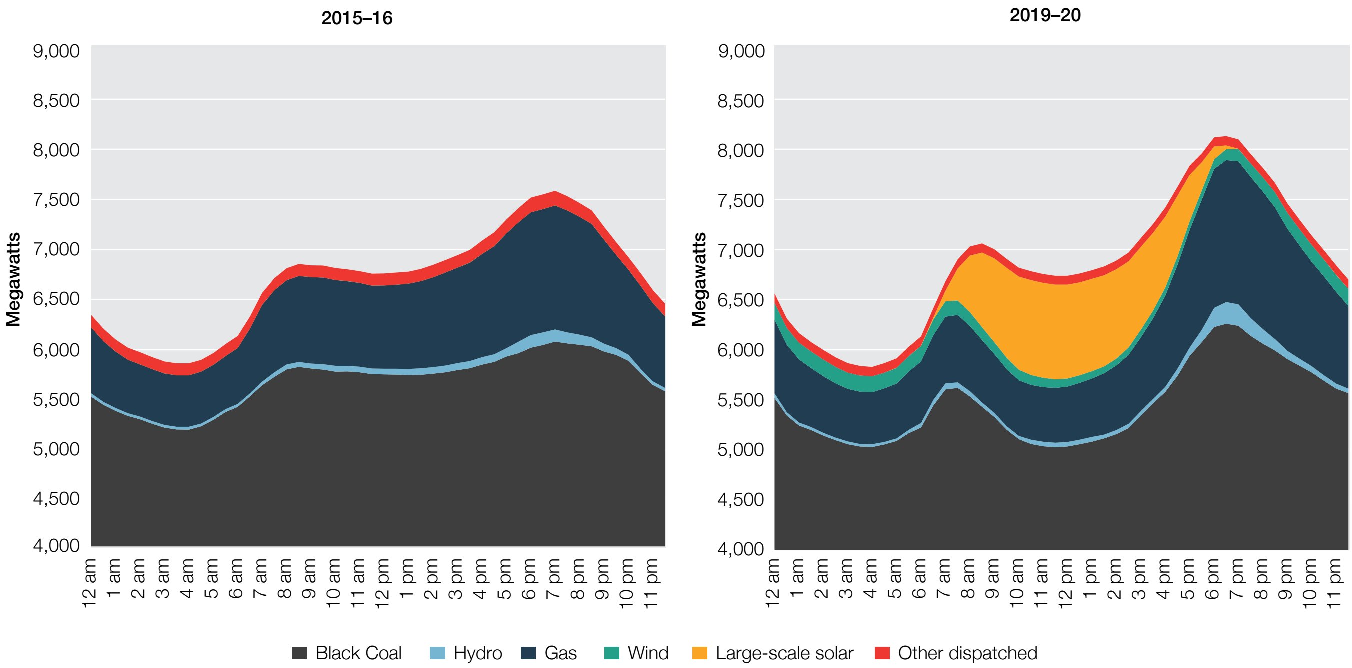
2.5.2 The generation mix is changing during the day as solar generation becomes more significant

The generation mix is changing throughout the day as both rooftop and large-scale solar have greater significance in the market. This is particularly seen in Queensland, the region with the highest penetration of large-scale solar and second highest of rooftop solar (section 2.2.1).

In 2019–20, large-scale solar generation accounted for 6% to 14% of generation during daylight hours (8 am to 5 pm) on average (figure 2.11). At the same time there has been a 1% to 2% reduction in total generation in the middle of the day since 2015–16, driven by rooftop solar replacing generation required from the grid. While solar primarily displaced coal and gas generation during these times, these fuel types were still required for the evening peaks and throughout the night. As a result, dispatchable generation output, including hydro, has become much more varied throughout the day, with lower output in daylight hours and increased generation in the evening peak.

Other regions follow similar patterns of solar displacing dispatchable generation during daylight hours with greater variability in dispatchable output throughout the day. But in Queensland the strong penetration of large-scale solar coincided with lower wind generation in the middle of the day, whereas in other states on average wind generated fairly evenly across the day.

Figure 2.11 Average Queensland generation by time of day, by fuel type



Source: AER analysis using NEM data.

Note: Figure presents outcomes in NEM time (i.e. Australian Eastern Standard Time). Values of y-axis do not start at zero in order to emphasise the changes in generation for all fuel types.

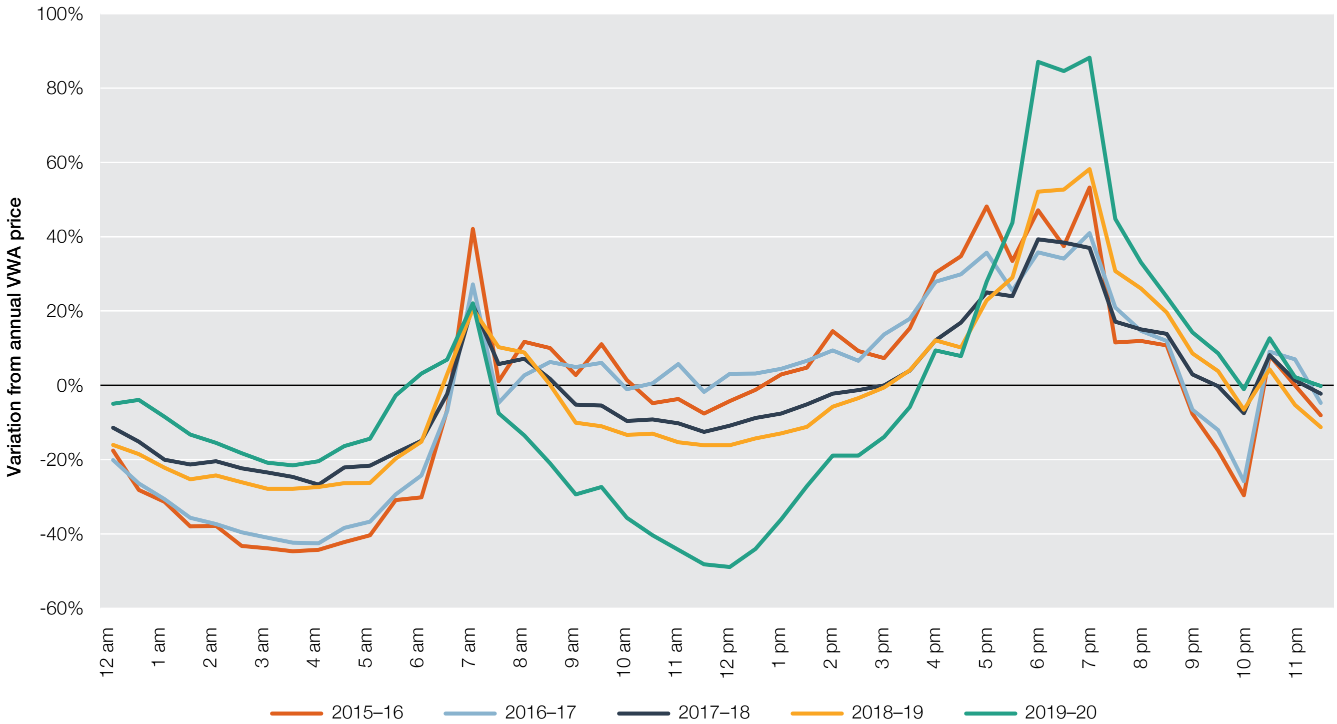
2.5.3 Prices are varying throughout the day

Increased solar penetration is also influencing prices throughout the day, mirroring trends seen in demand and generation. As with generation, Queensland has seen the most significant changes in pricing patterns.

Although pricing patterns can fluctuate between years depending on broader market conditions, in 2019–20 there was a significant shift in the variability of volume weighted average prices by time of day (figure 2.12). Average prices during daylight hours and particularly the middle of the day were much lower relative to the daily price than in previous years. This reflects lower grid demand and increased low cost generation during daylight hours, as well as lower offers from generators more generally. During evening peaks, however, average prices were up to 90% higher than the daily price in 2019–20. This compares to average prices during the evening peak that were 40% to 60% higher than daily prices in the previous 4 years. Overnight (11 pm to 6 am) average prices did not fall as low as in previous years.

Other regions followed similar patterns, with prices generally lower in the middle of the day and higher in the evening peaks and overnight compared to previous years. This trend was more apparent in those states that have a higher penetration of solar, such as South Australia.

Figure 2.12 Queensland prices by time of day (capped at $300 per MWh)



Source: AER analysis using NEM data.

Note: Variation from financial year volume weighted average (VWA) price, with spot prices capped at $300 per megawatt hour (MWh). VWA 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. The capped VWA for each financial year used as base to calculate the extent of variation through the day were: $55 (2015–16), $79 (2016–17), $74 (2017–18), $83 (2018–19) and $55 (2019–20) per MWh.

2.6 Prices for FCAS have increased

FCAS are used to maintain the frequency of the power system (box 8.1). There are markets for both energy and FCAS, which the Australian Energy Market Operator (AEMO) manages through a process called co-optimisation. To minimise overall costs, AEMO co-optimises offers and requirements between energy and FCAS markets simultaneously (box 8.2). As the market transitions to more intermittent generation there has been more variation in system frequency and FCAS has become more important in balancing the safety of the system.

The prices of many of these services increased between 2016 and 2020, despite market conditions creating some variability quarter on quarter. Historically, average quarterly global FCAS prices were relatively low, generally not exceeding $3 per MW. However since early 2016, FCAS prices for both regulation and contingency services have increased significantly, reaching over $40 per MW for raise regulation and raise 6 second services (figure 2.13).

The uplift in prices has been driven by extreme price events, the changing generation mix and shifts in bidding behaviour. Chapter 8 discusses FCAS markets in more detail.

Figure 2.13 Average global FCAS prices

Source: AER analysis using NEM data.

Note: Figure shows the global average quarterly price for all FCAS markets. The majority of the time, FCAS can be shared over interconnectors between all regions. In these times we consider the markets for FCAS to be global.

2.7 COVID-19 has impacted the NEM

In 2020 the COVID-19 pandemic resulted in social and economic disruption across Australia and the world. While the NEM has been affected by the pandemic, these impacts have been more moderate than first expected.

The pandemic affected physical management of the power system. Local and international travel restrictions created difficulties in sourcing maintenance resources, and as a result participants reported they were delaying maintenance schedules into late 2020 and 2021. Social distancing requirements also extended the time needed for maintenance and thus increased the associated costs.

Economically, COVID-19 has resulted in significant falls in energy commodity prices, due to lower global consumer demand and government-imposed lockdowns. International LNG prices, which were already in a downward cycle, declined at an accelerated pace since the COVID-19 outbreak began. Similarly international coal prices, which fell sharply in 2019, declined further.[13] However the prices of energy commodities are likely to recover, as global demand recovers and supply cuts cause markets to tighten.[14]

In terms of local consumption, there was only a modest impact on grid demand from COVID-19. Restrictions resulted in drops in commercial load, but these were somewhat offset by increases in residential load. Heavy industry was largely unaffected. There were also changes in consumption patterns throughout the day, but these varied between regions depending on local restrictions.[15 16]

Broadly, the Australian and global economic downturns as a result of COVID-19, as well as uncertainty about the future outlook, may have impacts on the willingness to invest and the ability to obtain financing. Vertically integrated players may be impacted by bad debt from their retail portfolios increasing, which we are monitoring closely.[17]

13 DISER, *Resources and energy quarterly June 2020*, June 2020, p. 4.

14 DISER, *Resources and energy quarterly September 2020*, September 2020, p. 4.

15 AEMO, *Quarterly Energy Dynamics—Q2 2020*, 22 July 2020, pp. 8–9.

16 AEMO, *Quarterly Energy Dynamics—Q3 2020*, 21 October 2020, p. 9.

17 AER, *Weekly retail market dashboards—COVID-19*, AER website.

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

Key points

- The market continues to be concentrated. However since our last report there has been some lessening of market concentration, with new entry from large-scale solar and wind generators. A few large vertically integrated participants control significant generation capacity and output in each region. Ownership among fast response flexible generation is particularly concentrated.
- The market share of large vertically integrated participants has generally remained unchanged over the past 2 years, except in South Australia where their market share has declined in both generation and retail markets.
- Interconnectors allow imports from neighbouring regions, providing some competitive constraint. Interregional competition is limited by the capacity of the interconnectors.
- 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. Regions with high solar penetration are seeing shifts in concentration throughout the day.
- While participants may have an ability to exercise market power at times, they may not have an incentive to do so. Incentives are influenced by a range of factors including exposure to spot prices through contracting or vertical integration, 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 increased recently, although liquidity remains a concern in South Australia.

The structure of a market influences competition in that market. A market controlled by a small number of large participants 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, when demand is high, or when supply is constrained. That said, the ability to exercise market power is distinct from incentives to exercise that power. A participant's incentives will be influenced by a range of factors including its ability to contract against spot prices, the extent to which it is vertically integrated and government direction or regulation.

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 highlights how market concentration varies throughout the day in some regions.
- Section 3.5 describes how it is not necessarily profitable for a participant with market power to exercise it.
- Section 3.6 assesses how the liquidity of contract markets can support effective risk management.
- Section 3.7 explores how demand response has developed.

3.1 Despite significant new entry, generation ownership remains concentrated

Despite significant new entry since 2018, a small number of participants continue to control a significant proportion of generation capacity and output in the National Electricity Market (NEM). This continues to provide opportunities for participants to exercise market power.

We used standard market concentration metrics to assess market concentration in each region of the NEM and the extent this has changed since our 2018 report (box 3.1).

Box 3.1 How we assess market 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 of concentration. This report uses 2 measures of market share:

- **Market share by registered capacity** measures a market participant's share of total registered capacity on a given date. It is a good overall measure of total market capacity. However, this measure does not account for outages or how different types of plant are offered into the market. This measure does not capture factors that may affect a participants' ability to generate such as network constraints, fuel availability and plant conditions.
- **Market share by generation output** measures a participant's share of annual energy delivery. It better reflects the nature of a market participant's generation fleet and contribution to market outcomes. However, it does not account well for market participants with flexible generation plant with an ability to respond to peak prices, but operated infrequently.

Herfindahl Hirschman Index (HHI)

HHI is a useful measure of market concentration as it allows for comparisons across regions and through time.

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

We calculated the index using participant market share based on 5 minute bid availability. Unlike measures based on capacity or output, bid availability accounts for outages, fuel availability and bidding behaviour. This provides a more dynamic assessment of the levels of concentration in the market based on changing market conditions.

Pivotal supplier test (PST)

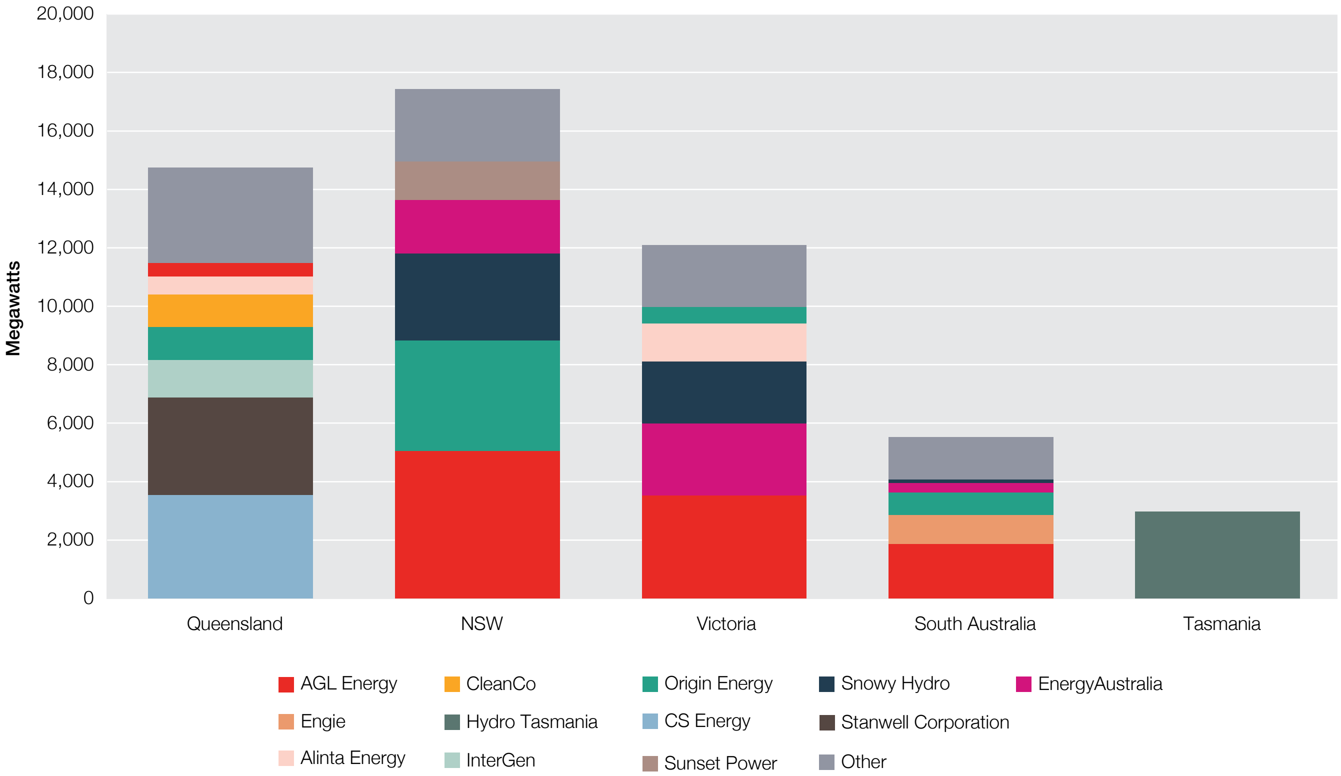
The pivotal supplier test (PST) measures the extent to which one or more participants is 'pivotal' to clearing the market. A participant is pivotal if market demand exceeds the capacity of all other participants, accounting for possible imports. In these circumstances, the participant must be dispatched (at least partly) to meet demand. The PST gives an indication of the risk of the exercise of market power.

3.1.1 A few participants control the majority of generation in each region

A few large participants continue to control a significant proportion of generation capacity and output in each region of the NEM (figure 3.1 and figure 3.2). For 2019–20:

- In Queensland, state-government owned participants Stanwell Corporation and CS Energy controlled around half of the region's generation capacity and two thirds of its output.
- In NSW, AGL Energy and Origin Energy controlled half of the region's generation capacity and over two thirds of its output.
- In Victoria, AGL Energy, EnergyAustralia and Alinta Energy controlled 60% of the region's generation capacity, and 87% of its output.
- In South Australia, AGL Energy and Engie controlled around half of the region's generation capacity and over half of its output.
- The most concentrated region is Tasmania, where state government owned Hydro Tasmania controls all generation.[18]

Figure 3.1 Market share by registered capacity, 30 June 2020



Source: AER analysis using NEM data.

Note: Registered capacity market share uses registered capacity of all market scheduled and semi-scheduled generation (excluding market loads) registered as at 30 June 2020. Market shares determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

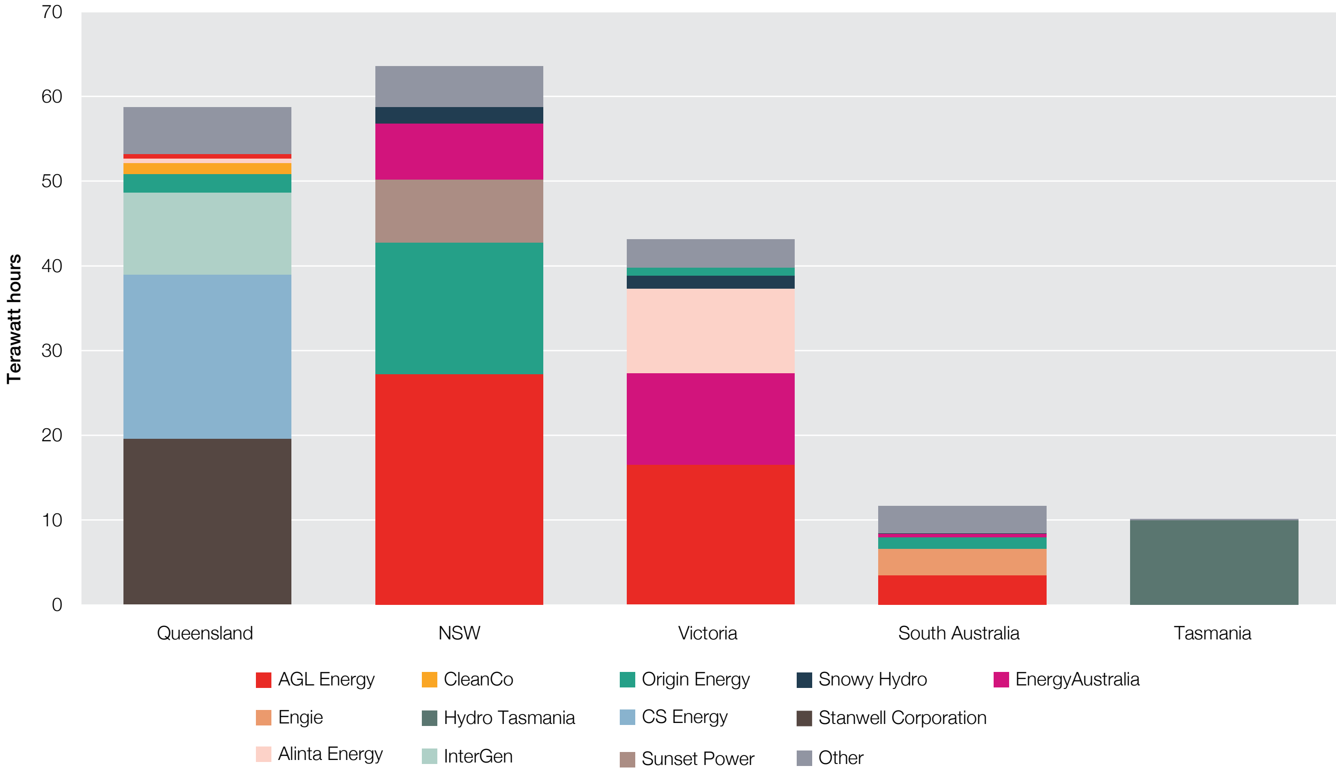
There are 4 participants that have a significant presence across multiple regions of the NEM and have sizeable market shares in NSW, Victoria and South Australia.

AGL Energy is the largest participant in NSW, Victoria and South Australia, and continues to control the most capacity in the NEM. In the 2 years since our last report, new generation investment has allowed AGL Energy to retain a similar market share—controlling more than 20% of capacity and around 25% of generation output across the NEM. Origin Energy is the next largest participant, with generation across all mainland regions and accounting for around 12% of registered capacity and 11% of output. EnergyAustralia controls 9% of registered capacity in the NEM, with a presence in NSW, Victoria and South Australia, and accounts for around 10% of output.

18 Hydro Tasmania has long-term offtake agreements for generation it doesn't own in Tasmania which gives it control over the assets. Since 2018 new generation that has been built with long-term offtake agreements in place includes Granville Harbour and Cattle Hill wind farms.

Snowy Hydro controls almost 10% of generation capacity in the NEM. Despite its significant generation portfolio, Snowy Hydro only contributed 1.8% of total output in 2019–20, down from 2.4% in 2017–18. Snowy Hydro's portfolio primarily consists of water-constrained hydro and higher cost gas generation across NSW, Victoria and South Australia (section 3.1.2). As such, Snowy Hydro typically operates during periods of high demand.

Figure 3.2 Market share by total generation output, 2019–20



Source: AER analysis using NEM data.

Note: Generation market share uses 30 minute metered data, aggregated for the entire 2019–20 financial year and expressed in terawatt hours. Where changes in ownership have occurred throughout the year, output is attributed to the owner of the generation unit at the point in time of the generation output. Market shares determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

Since the last report, the market has become slightly less concentrated in most regions. Over this period, around 6,100 megawatts (MW) of new capacity has entered the market, the majority being wind or large-scale solar generation. This has meant some smaller market participants, such as Neoen and Tilt Renewables, have increased their market share. However, AGL Energy commissioned the most new generation capacity since our 2018 report, including wind and fast start gas to replace 2 older gas units.[19]

In addition to new generation entering the market, some restructuring has altered market concentration. The Queensland Government restructured its 2 participants, CS Energy and Stanwell Corporation, into 3 with the creation of CleanCo.[20] This shifted more than 1,000 MW of capacity away from the 2 largest participants, slightly reducing market concentration in the region from October 2019.[21]

In early 2018, there was also a shift in ownership in Victoria. Engie exited the Victorian market when it sold its 1,000 MW Loy Yang B power station, to Alinta Energy.[22]

As well as using market share, we used the Herfindahl Hirschman Index (HHI) to assess the market concentration of the NEM (box 3.1). HHI assesses concentration based on regional bid availability throughout each year and provides a dynamic assessment of concentration in the market. However, this measure does not account for the competitive constraint provided by interconnection, and thus can overstate the risk of uncompetitive outcomes.

19 Barker Inlet began operation in October 2019, replacing 2 units at Torrens Island A which closed in September 2020.

20 This restructure was identified as part of the Queensland government's energy plan. Department of Energy and Water Supply, *Powering Queensland Plan*, Queensland Government, released June 2017.

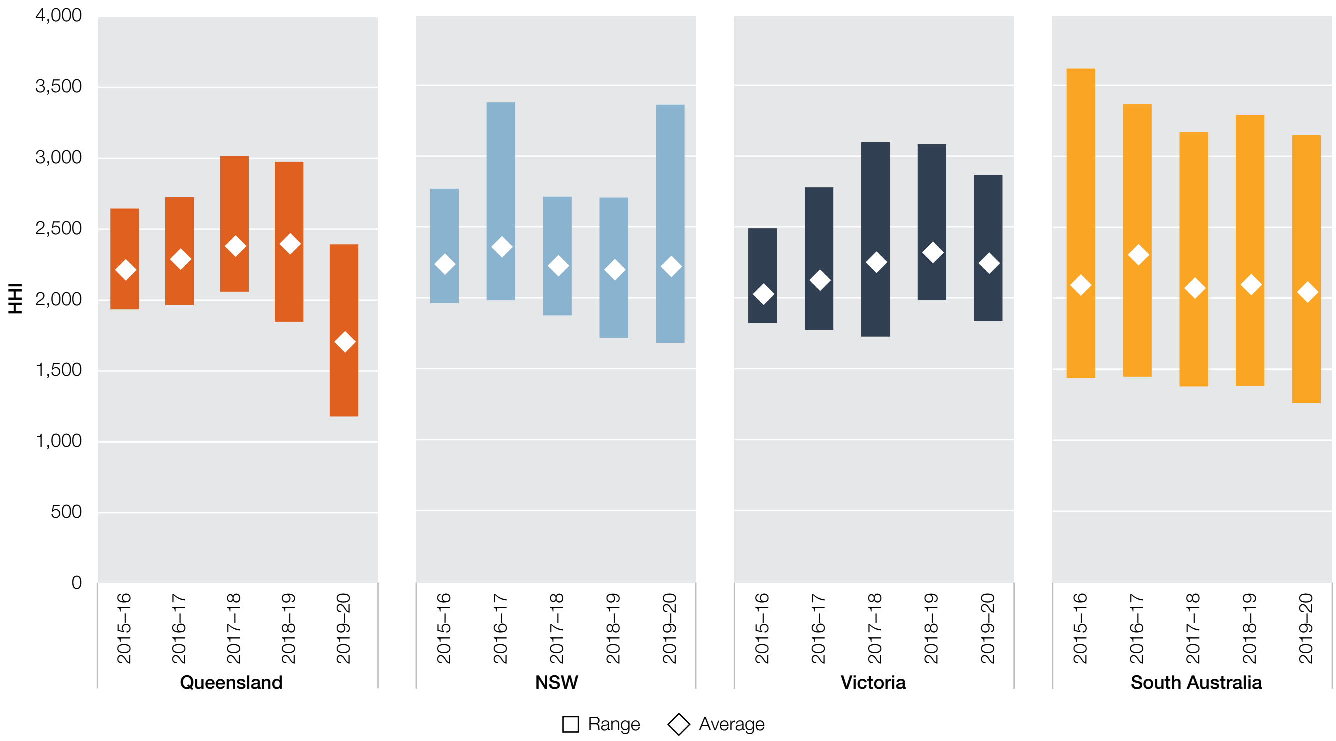
21 CleanCo was created in December 2018, and the transfer of generator asset ownership occurred in October 2019. For more information see CleanCo website.

22 Alinta Energy, *Loy Yang B Power Station*, Alinta Energy website.

Other regulators also use HHI thresholds to assess concentration. The US Federal Trade Commission broadly categorise HHI above 2,500 as highly concentrated.[23] Similarly, the Australian Competition and Consumer Commission's (ACCC) merger guidelines indicate it is generally less likely to identify competition concerns when the post-merger HHI is less than 2,000.[24] We have not determined our own HHI concentration thresholds, but rather use HHI as a tool to compare the degree of concentration across regions and through time.

The average bid availability HHI for 2019–20 in all regions except Queensland was above 2,000, with little variation in recent years (figure 3.3). In Queensland the creation of CleanCo and new entry of large-scale solar in 2019–20 saw HHI values shift down significantly. There is however significant variation between the smallest and largest HHI values when examining individual dispatch intervals. The range of HHI values tends to be highest in South Australia, where there is the largest penetration of intermittent generation.

Figure 3.3 Variability in bid availability Herfindahl Hirschman Index



Source: AER analysis using NEM data.

Note: Figure shows the maximum, minimum and average HHI by 5 minute bid availability for each financial year in each region. Ownership determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

3.1.2 Ownership of flexible capacity continues to be concentrated

A few participants control significant flexible generation capacity in NSW, Victoria and Tasmania (figure 3.4).[25]

Snowy Hydro controls more than 5,000 MW of flexible generation capacity and accounts for 42% of all flexible capacity in the NEM. Most of these assets are located in NSW and Victoria and as a result, Snowy Hydro controls 72% of flexible capacity in NSW and 61% in Victoria. In addition, Snowy Hydro is developing Snowy 2.0, which would add a further 2,000 MW of flexible capacity to its portfolio.

Origin Energy is the second largest provider of flexible generation with significant capacity across the mainland. Collectively, Snowy Hydro and Origin Energy control almost all flexible capacity in NSW and more than three quarters in Victoria.

In Queensland and South Australia, ownership of flexible capacity is more diverse. In South Australia 7 participants control almost all flexible generation capacity. In Queensland, the creation of CleanCo consolidated almost all of the flexible generation capacity of CS Energy and Stanwell Corporation into one portfolio. As a result, market

23 US Department of Justice and the Federal Trade Commission, *Horizontal merger guidelines*, 2010, pp. 18–19.

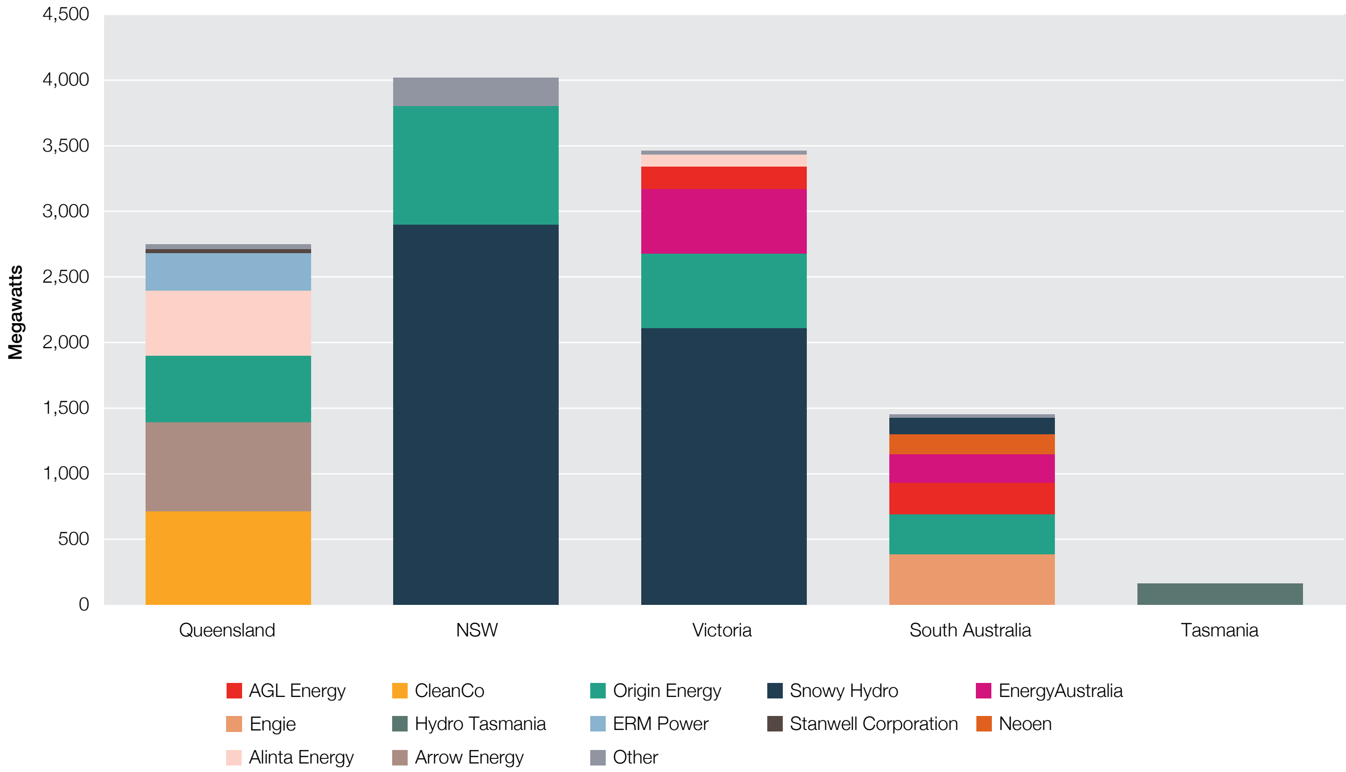
24 ACCC, *Merger guidelines*, updated 2017, p. 35.

25 Flexible 'fast response' generation refers to generators that can respond quickly to changing market conditions. In this report we have classified 'flexible' generating units as any unit registered with AEMO as 'fast'. To be registered as 'fast' a generating unit must be able to start up and increase generation within 30 minutes of receiving a dispatch instruction.

concentration of flexible capacity has increased since our last report with most flexible capacity now being controlled by 5 participants, down from 6.

In Tasmania, Hydro Tasmania controls all generation capacity, flexible or otherwise.

Figure 3.4 Market share for flexible generation capacity, 30 June 2020



Source: AER analysis using NEM data.

Note: Registered capacity market share uses registered capacity of all flexible market scheduled and semi-scheduled generation (excluding market loads) registered as at 30 June 2020. In this report we have classified 'flexible' generating units as any unit registered with AEMO as 'fast'. Market shares determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the market share for that capacity is attributed to the intermediary.

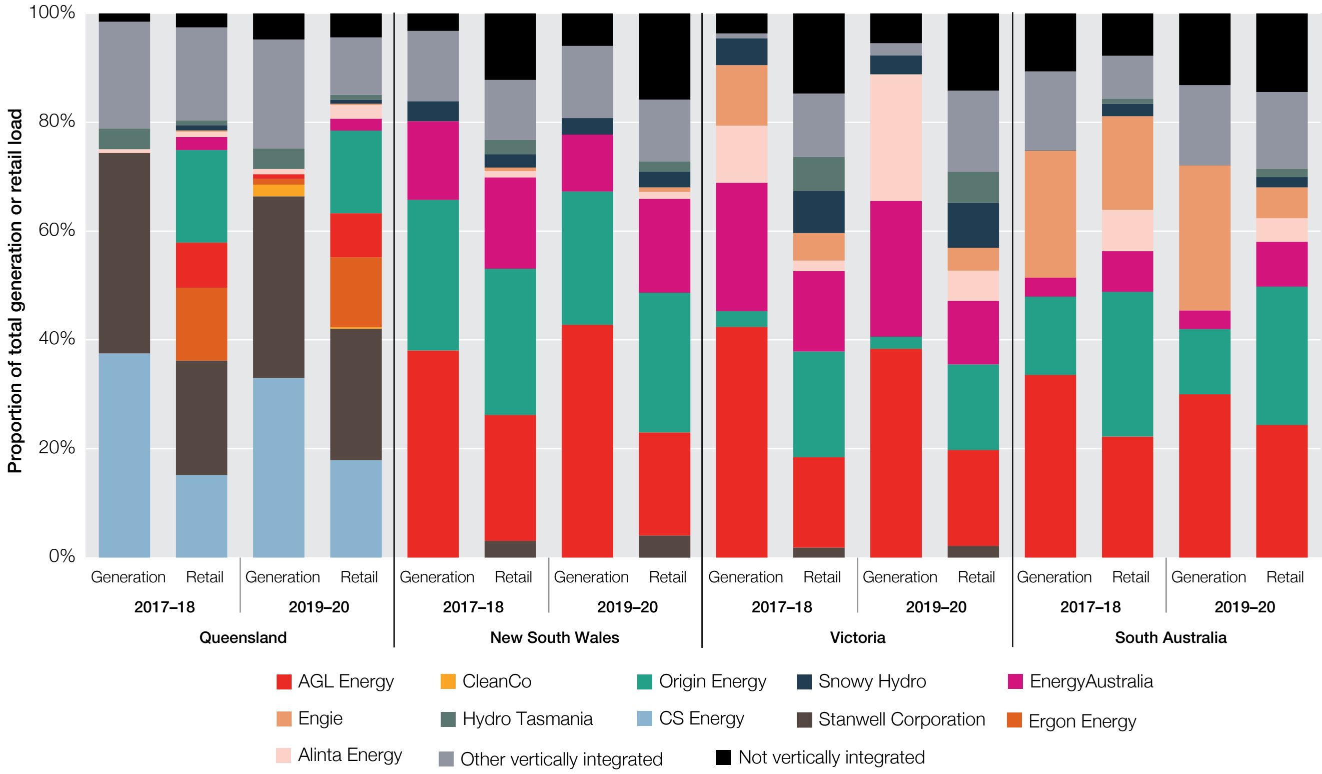
Flexible generation is playing an increasingly important role in the market (section 2.2.2). We will continue to monitor concentration and competition in the supply of flexible capacity in addition to broader market outcomes.

3.1.3 Most generators in the NEM are vertically integrated

Vertical integration is a key feature of the NEM. It occurs when a market participant combines generation and retail operations. Since our last report, a few large vertically integrated participants have continued to control significant generation and account for the majority of retail load in each region of the NEM (figure 3.5).[26]

26 Retail market share is measured based on the load of a retailer's customers over the relevant period. This differs from the approach used in our 2018 report, which calculated market share based on the number of small retail customers of each retailer. The new approach provides a like for like comparison of energy between generation and load in each region.

Figure 3.5 Vertical integration in the NEM, 2017–18 and 2019–20



Source: AER analysis using NEM data.

Note: Generation market share is based on 2017–18 and 2019–20 total generation output by participant ownership as defined in AEMO's generator registration of market participants. Retail market share is based on 2017–18 and 2019–20 total load by retailer ownership. 'Other vertically integrated' indicates other participants that are vertically integrated (e.g. Infigen Energy). 'Not vertically integrated' indicates other participants that are not vertically integrated including merchant generators and standalone retailers.

In 2019–20, the 4 largest vertically integrated participants in each region accounted for the majority of generation output and more than half of all retail load:

- In NSW, they accounted for 81% of generation output and 65% of load.
- In Victoria, they accounted for 89% of generation output and 51% of load.
- In South Australia, they accounted for 72% of generation output and 64% of load.

In Queensland, state government owned businesses (CS Energy, Stanwell Corporation and CleanCo) accounted for 69% of generation output and 42% of load in 2019–20. The Queensland government also owns major retailer Ergon Energy, which services 13% of retail load in the region and 1% of generation output.

The market share of large vertically integrated participants has remained relatively unchanged over the past 2 years, except in South Australia where their market share has declined in both generation and retail markets. This marks a change in the trend seen in our last report of increasing vertical integration in the NEM.

Despite collectively owning more generation than needed to service their retail load, the profile of each large vertically integrated business varies significantly. Among the 6 largest businesses, on average AGL Energy and Alinta Energy tend to have larger generation portfolios, while EnergyAustralia and Engie have relatively more balanced portfolios. Origin Energy and Snowy Hydro need to service a larger retail load than their generation fleet accounts for, but have a greater share of peaking generation in their portfolios, which allows them to manage the risk of high prices. These differences, along with imbalances between generation and retail load at the regional level, drive different contracting strategies across the businesses.

3.2 Interconnectors provide some competitive pressure to neighbouring regions

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 allows lower-priced generation in adjoining regions to compete with higher-priced local generation. As a result, strong interregional flows provide some competitive pressure on participants within a region.

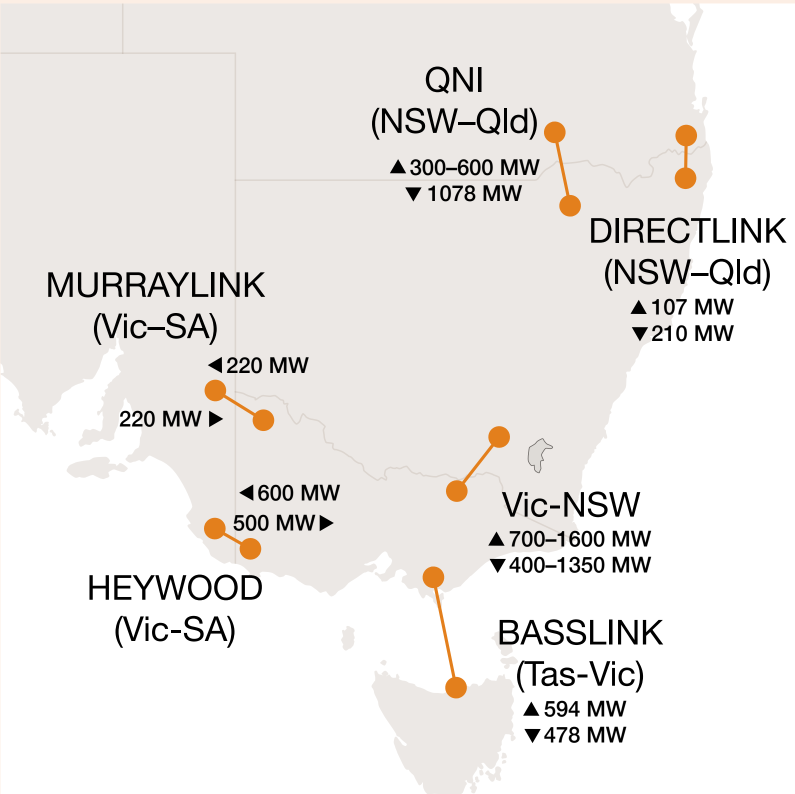
Box 3.2 Interconnectors in the NEM

Transmission interconnectors enable energy transfers between the National Electricity Market's (NEM) 5 regions. Interconnectors generally 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 (AEMO) 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 (price separation).

Figure 3.6 Interconnectors in the NEM



Source: AER analysis using NEM data.

3.2.1 Flows between regions remain strong

Despite variations from region to region, flows between regions remain strong, which promotes effective competition. When there is trade between regions, lower-priced capacity in adjoining regions can compete with higher-priced local capacity. In an efficient market, flows change to meet market needs and generation flows from low to higher priced regions.

Due to an abundance of low priced brown coal generation which drove some of the lowest prices in the NEM, Victoria was historically a significant net exporter to NSW and South Australia (figure 3.7).[27] Following the closure of Hazelwood power station in March 2017, the flow of interregional trade shifted. South Australia exported more to Victoria and became a net exporter.

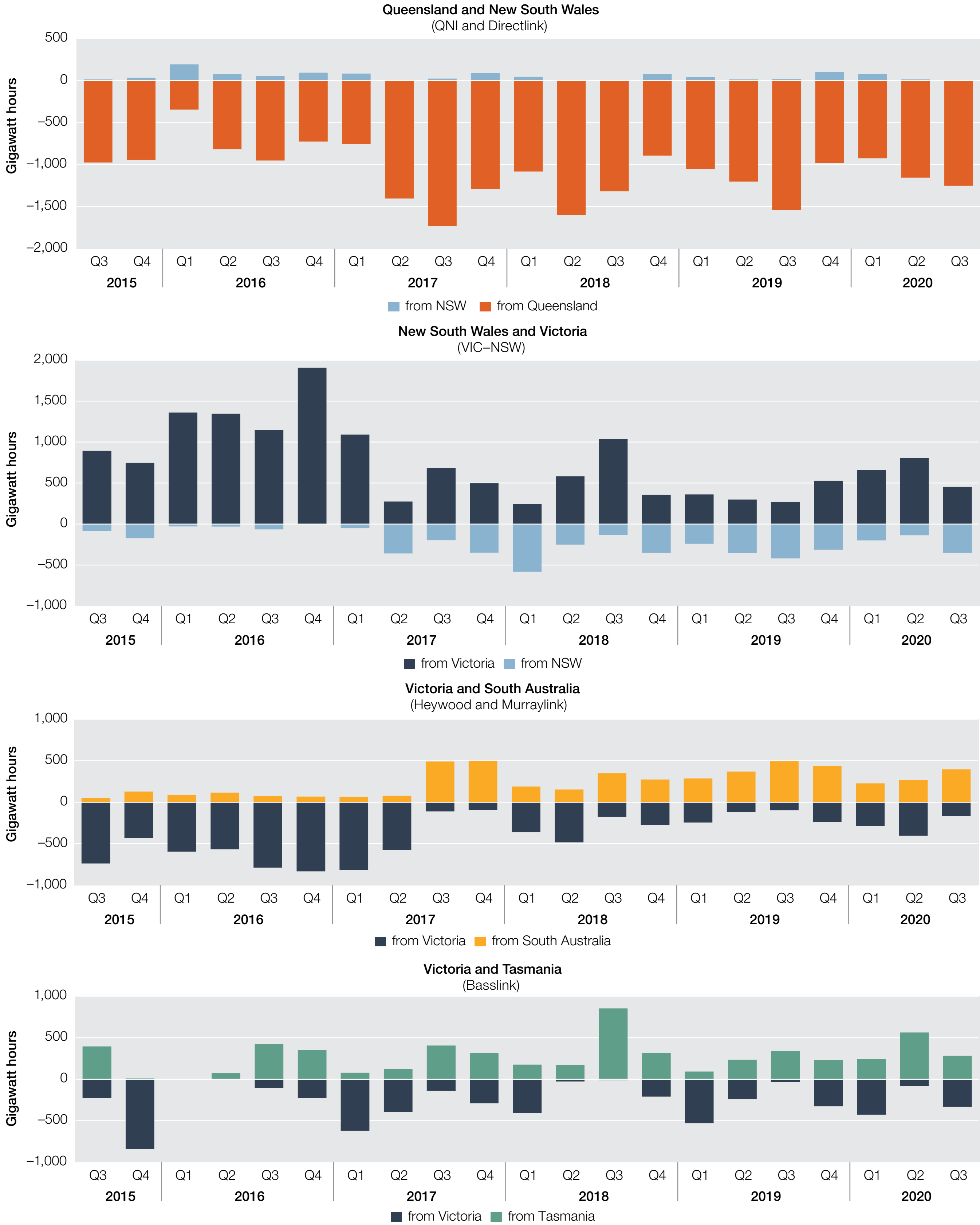
Queensland, which was already a net exporter, has exported even more since the closure of Hazelwood. This reflects the abundance of lower priced generation in Queensland, which has seen it often be the lowest priced region in the NEM (section 2.1).

In NSW, the shift in wholesale prices has driven an increase in imports from Queensland and less imports from Victoria. NSW also exported more generation into Victoria following Hazelwood's closure.

There are significant variations in flows between Victoria and Tasmania from quarter to quarter. These flows are highly dependent on a range of factors including Tasmanian rainfall, which affects dam levels for hydro generation; Victorian spot prices; and the availability of the Basslink interconnector, which has suffered multiple extended outages in recent years.

27 AER, *Hazelwood advice*, 29 March 2018, p. 2.

Figure 3.7 Total quarterly exports across regional boundaries



Source: AER analysis using NEM data.

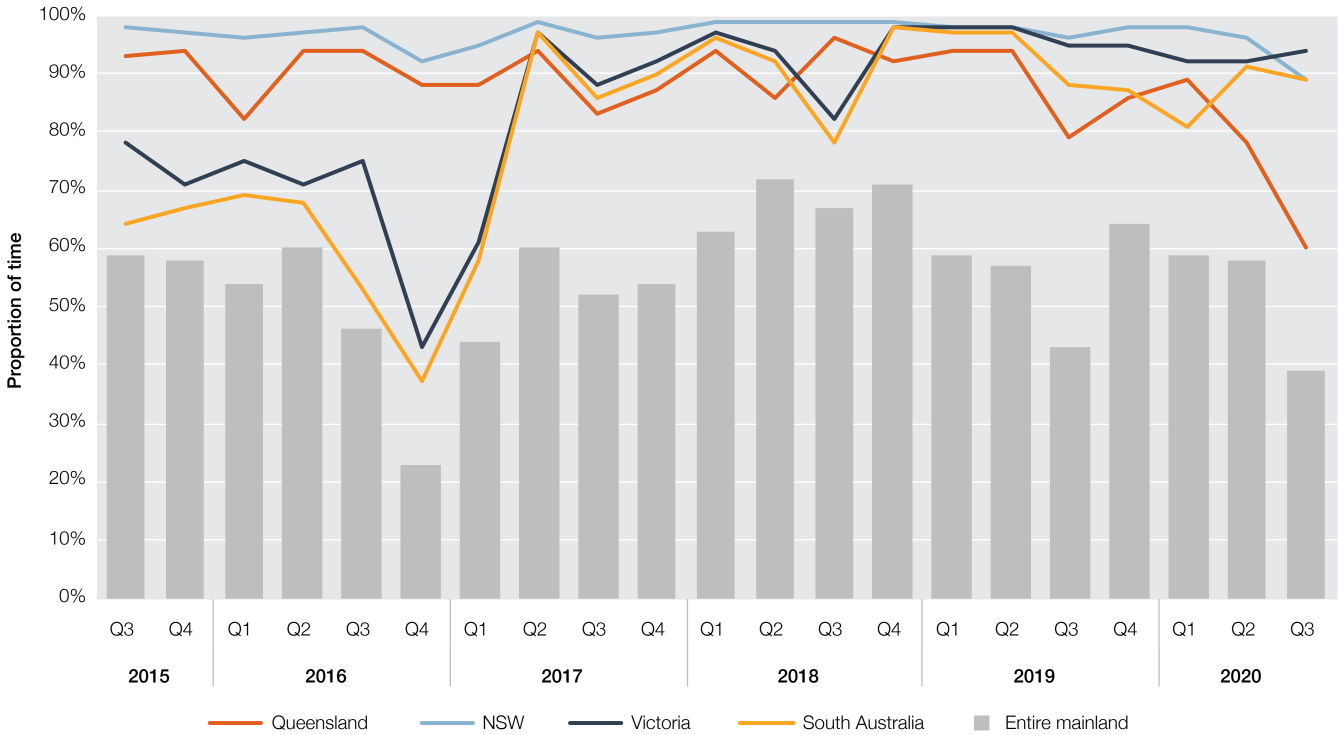
Note: Total quarterly interconnector flows. Show exports by regional boundaries. Where multiple interconnectors connect the same regions, these have been displayed on the same parts of the figure.

3.2.2 Competition between regions is limited by interconnector capacity

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

Price separation occurs when there is not enough interconnector capacity to equalise the spot price between joined regions, and an importing region must rely on local generation to meet demand. During periods of price separation, prices in the importing regions tend to be higher than prices in the exporting region. Conversely, when generation is able to flow freely between regions, interconnectors are unconstrained and prices between regions tend to align. As such, price alignment can be used as an indicator for interregional competition. Price alignment rates have varied significantly across the mainland NEM regions over the past 5 years (figure 3.8).

Figure 3.8 Regional price alignment



Source: AER analysis using NEM data.

Note: Mainland price alignment indicates the percentage of time where the entire mainland has free-flows between regions. Regional alignment indicates the percentage of time when the relevant region had free-flows across interconnectors with at least one other region.

Interpreting price alignment outcomes as an overall indicator of competition requires care. For example, when Hazelwood power station closed in March 2017, alignment rates between South Australia and Victoria increased significantly. The higher alignment rates between the regions did not indicate increased competition. Rather, with less low cost brown coal generation available for export from Victoria, the Heywood interconnector operated at its technical limit less frequently. On the other hand, in 2020 Queensland's alignment with the rest of the NEM decreased from 89% of the time in Q1 2020, to only 60% of the time in Q3 2020. These changes in alignment rates were driven by work to upgrade the Queensland-NSW interconnector (QNI) which started in May 2020. While the works are underway flows have been limited from Queensland into NSW. As a result, in the middle of the day flows were often constrained to less than half of the interconnector's full technical capacity, which also coincides with the most low priced capacity on offer from large-scale solar generation. Consequently, while there were still significant exports into NSW over this period, not all of this low priced capacity could be exported and alignment rates were lower. This reduction in daytime flows also meant there was less competitive pressure on NSW generators from their Queensland counterparts.[28]

Alignment rates have tended to be higher in NSW and Victoria, which connect to more than one region. This could suggest that regions with interconnectors to multiple regions may face greater competitive pressure from interregional trade than regions that are joined to only one.

When the same large participants are present on both sides of an interconnector, competition from interregional trade may also be restricted. For example, AGL Energy has significant generation assets in NSW, Victoria and South

28 AER, *Wholesale markets quarterly—Q3 2020*, 12 November 2020, p. 10.

Australia and it is unlikely its generators in one region would actively compete against its generators in other regions during periods when interconnectors are unconstrained. Snowy Hydro and EnergyAustralia also have significant generation across connected regions.

3.2.3 New interconnectors have the potential to change interregional competition

New interconnectors can improve the reliability and security of the power system and may provide an increased competitive constraint on large participants in neighbouring regions. New interconnectors can also link regions that have never been connected before and in some circumstances could provide an alternative to generation investment.

In considering future interconnector planning, we should recognise that energy consumers ultimately bear the cost of new investment. To minimise the risk of over-investment (where consumers pay more than is efficient) or under-investment (where consumers experience lower reliability or higher than necessary wholesale prices), interconnector investment decisions currently undergo cost-benefit analyses.

The QNI minor upgrade is the latest project to have passed all the approval stages and construction is currently underway, which will enable more generation to flow between Queensland and NSW.[29] This could provide increased competitive constraint on participants in NSW, particularly in light of the expected closure of Liddell power station over 2022 and 2023.

There are a considerable number of potential new interconnectors on the horizon.[30] These would fundamentally shift how generation flows between regions across the NEM, and could have impacts on future generation investment and competition. We will continue to monitor and report on the impact of new interconnectors on market dynamics.

3.3 A few large participants are needed to meet demand for a significant proportion of the time

In all regions, the generation 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 from neighbouring regions. At these times, the large participants are considered jointly pivotal to meeting demand and have an increased ability to exercise market power.

The pivotal supplier test (PST) evaluates the potential for the exercise of market power based on whether particular participants are needed to meet demand (box 3.3). The PST accounts for generation ownership, outages, and changing market conditions such as demand and interconnector availability. We have examined the extent to which the largest participant (PST-1) or 2 largest participants (PST-2) are pivotal for each mainland NEM region.

29 AER, *Expanding NSW-QLD transmission transfer capacity*, AER decision, 30 March 2020.

30 AEMO, *2020 Integrated System Plan*, July 2020, pp. 13–16.

Box 3.3 Measuring competition using the Pivotal Supplier Test

The pivotal supplier test (PST) 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, accounting for possible flows across interconnectors. In these circumstances, the participant must be dispatched (at least partly) to meet demand.

We calculated the extent to which the largest participant (PST-1) or 2 largest participants (PST-2) are pivotal for each mainland National Electricity Market (NEM) region. We did this for every 5 minute period interval in 2017–18 and 2019–20. We then measured the percentage of time generation from these suppliers was required to meet demand.

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

$$\text{PST-1} = \frac{\text{total availability} + (\text{import limit} - \text{forced imports}) - \text{largest participant's availability}}{\text{demand} + \text{forced exports} - \text{forced imports}}$$

A PST-1 score greater than one means demand can be fully met without dispatching the largest participant. A score below one indicates that a particular market participant is pivotal to meeting demand, while a score above one indicates that demand could be met by other participants within the region.

PST-2 measures the ratio of demand that can be met by all but the 2 largest participants in a region. It is easier for one pivotal participant to exercise market power than 2 or more participants. But, PST-2 is still a useful measure because it indicates the risk of coordinated behaviour by 2 participants. The fewer participants required to meet demand, the greater the risk these participants could implicitly or explicitly coordinate pricing or output decisions.

Various factors may cause the PST to decline, including a rise in demand, a decrease in available generation capacity of other rival participants, or an increase in the proportion of available capacity supplied by the largest participant(s).

PST is a useful indicator for identifying the structural elements of market power. It also highlights combinations of participants that might be able to jointly exercise market power. However, there are a number of real-time practical considerations that cannot be factored into this analysis including constraints and price setting dynamics.

In the mainland regions, there are periods where the single largest participant is needed to meet demand, and therefore at those times has the ability to exercise market power. In 2019–20, the largest participant was needed to meet demand from 1% of the time in South Australia and up to 7% in Queensland. In Queensland, this was equivalent to around 25 days in 2019–20 and occurred primarily in the morning and evening peaks.

In Tasmania, Hydro Tasmania is always pivotal to meeting demand, but also faces regulation to reduce its incentives to exercise market power (section 3.5.2).

While PST-1 assesses the ability for a single participant to exercise market power, expanding the test to PST-2 gives an indication of the risk of coordinated behaviour by the 2 largest participants. In most regions the percentage of time the 2 largest participants are pivotal to meeting demand is significantly higher than the single largest participant. This demonstrates that there is a considerable risk of coordinated exercise of market power.

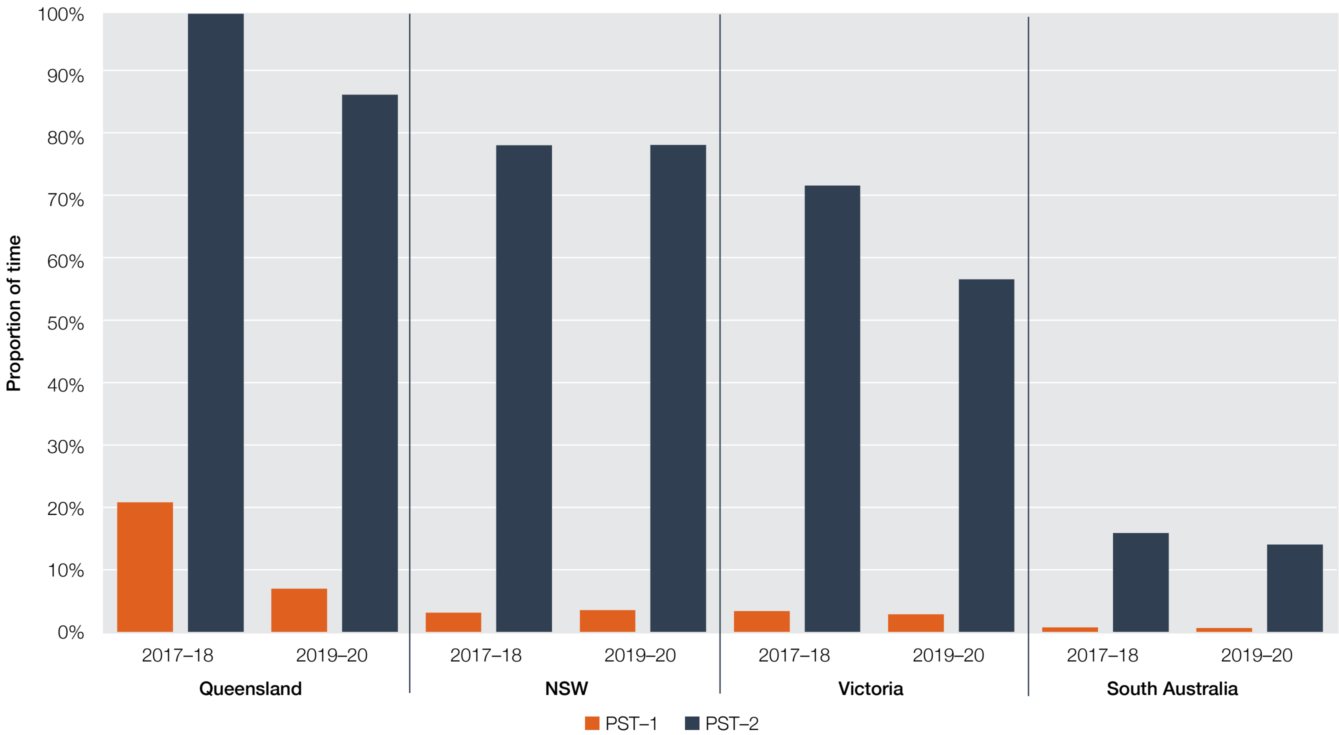
However, the 2 largest participants are generally required to meet demand less often than they were 2 years ago. And when they are pivotal, less of their generation is needed (figure 3.9). Our findings show:

- In Queensland, CS Energy and Stanwell Corporation were jointly pivotal around 87% of time in 2019–20. This has improved since they were pivotal 100% of the time in 2017–18, but still indicates a high risk of uncompetitive outcomes (section 3.4.1).
- In NSW, some generation from the 2 largest participants was needed to meet demand 79% of the time in 2019–20, unchanged since 2017–18. This highlights the NSW market has a high risk of uncompetitive outcomes. The pivotal suppliers were most likely to be AGL Energy, Snowy Hydro and Origin Energy.
- In Victoria, some generation from the 2 largest participants was needed to meet demand 58% of the time in 2019–20 down from 72% in 2017–18. This decrease was largely driven by an extended outage of a unit of

Loy Yang A power station in the second half of 2019 which reduced AGL Energy's market share.[31] The pivotal suppliers were most likely to be AGL Energy, Snowy Hydro, Alinta Energy and EnergyAustralia.

- In South Australia, some generation from AGL Energy and Engie was necessary to meet demand 14% of the time in 2019–20, slightly down from 16% in 2017–18. This highlights a lower potential risk of uncompetitive outcomes than in other regions.

Figure 3.9 Proportion of time some generation from the largest participant or largest 2 participants was needed to meet demand in 2017–18 and 2019–20



Source: AER analysis using NEM data.

Note: Figure shows the proportion of time that generation from the largest (or 2 largest) participant(s) was needed to meet demand in the 2017–18 and 2019–20 financial years. Ownership was determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the ownership of that DUID is attributed to the intermediary.

3.4 Regional markets are becoming less concentrated in the middle of the day, but generally remain concentrated in evening peaks

We assessed PST-2 in 2017–18 and 2019–20 at certain times of day to examine how market concentration, and the ability to use market power, may vary through the day. The generation of a few large participants is sometimes necessary to meet demand in all NEM regions (section 3.3). Also, there is a strong correlation between higher levels of demand and the need for the largest participants to meet demand, regardless of the time of day.

However over the past 2 years most regions have become slightly less concentrated during the day, when large-scale solar is generating. As a result, this has reduced the extent to which the largest generators are pivotal at these times.

3.4.1 Slightly lower market concentration has emerged in the middle of the day in Queensland

The most significant shifts in intraday market concentration have emerged in Queensland as a result of significant new entry of large-scale solar generation.

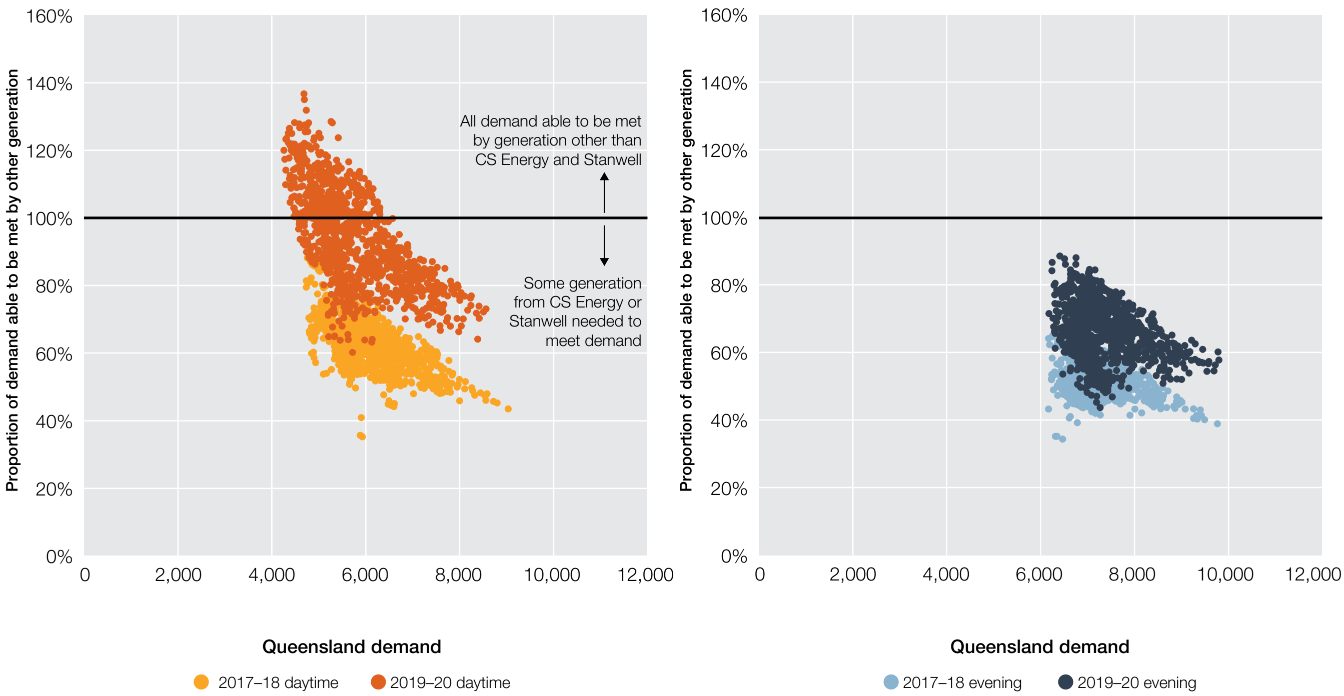
In 2017–18, CS Energy and Stanwell Corporation were pivotal to meeting all levels of demand, no matter the time of day (figure 3.10). In 2019–20, the entry of large-scale solar and the creation of CleanCo meant that during the day the 2 largest participants weren't always necessary to meet demand. For example:

31 AER, *Wholesale markets quarterly—Q3 2019*, November 2019, p. 14.

- When demand was less than 4,600 MW, other participants could satisfy demand and CS Energy and Stanwell Corporation were not required.
- When demand was between 4,600 MW and 6,800 MW during the day, other participants could meet demand to a greater extent than in 2017–18, though the 2 largest participants were still pivotal some of the time.
- At higher levels of daytime demand, CS Energy and Stanwell Corporation remain pivotal, although other participants are able to meet a larger share of demand.

While large-scale solar generation is having a significant impact on market concentration throughout daylight hours, the market is still highly concentrated during the evening peaks. Across both years, CS Energy and Stanwell Corporation were always pivotal in meeting the higher levels of demand in the evenings. This is still the case despite other participants being able to satisfy a greater proportion of demand after the creation of CleanCo.

Figure 3.10 Proportion of demand that can be met by generation other than the 2 largest participants in Queensland, 2017–18 and 2019–20



Source: AER analysis using NEM data.

Note: The PST-2 for Queensland tests Stanwell Corporation and CS Energy. Figure shows the proportion of demand that can be met by other generation (y-axis) and the corresponding level of demand (x-axis) for every hour in the 2017–18 and 2019–20 financial years. Ownership is determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the ownership of that DUID is attributed to the intermediary. Figure presents outcomes in NEM time (i.e. Australian Eastern Standard Time).

3.4.2 Variability of wind generation and rooftop solar has caused some lower daytime concentration in South Australia

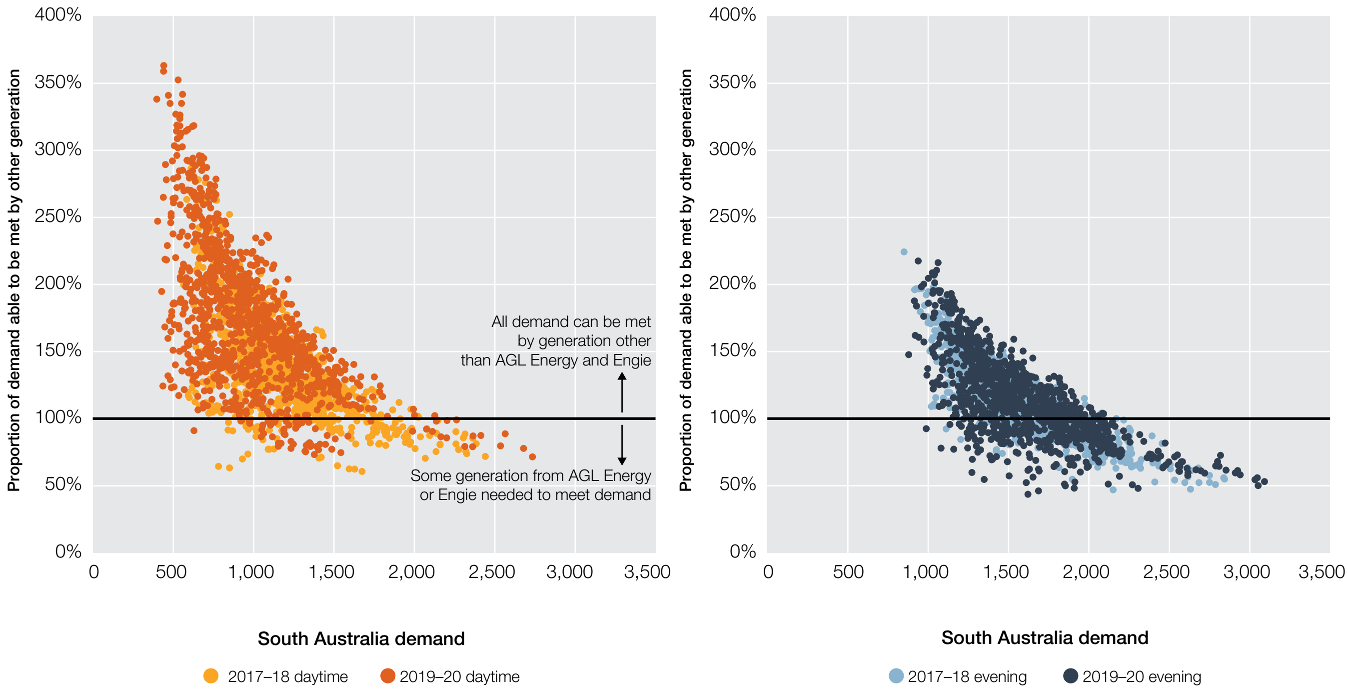
The significant penetration of wind in South Australia means the market is less concentrated overall and there is less of a contrast between market concentration in the day and evening. However, the importance of AGL Energy and Engie increases when wind generation output is low.

In South Australia, between 2017–18 and 2019–20 there has not been significant shifts in how pivotal the 2 largest generators are to meeting demand. AGL Energy and Engie are sometimes required to satisfy demand regardless of the time of day and for most levels of demand (figure 3.11).

In contrast to other regions, due to significant wind generation and potential for imports from Victoria, South Australian demand can be met by other participants the majority of the time. In 2019–20, there were occasions of low demand during the day and evening when generation from other participants or via interconnectors was 2 to 3 times the amount needed to meet demand. For example, when demand was less than 500 MW, there were some occasions where there was up to 1,750 MW of generation available via interconnectors or from participants other than AGL Energy or Engie. Nevertheless, the largest participants are always needed when demand is at its highest, during both the day and evening.

However, our analysis may overstate the degree of competitive pressure provided at times of low demand and high wind generation. In some circumstances, the Australian Energy Market Operator (AEMO) limits wind generation and directs gas participants to generate in order to maintain power system security. At these times, generation from AGL Energy and Engie may be required to meet demand as a result of these system requirements.

Figure 3.11 Proportion of demand that can be met by generation other than the 2 largest participants in South Australia, 2017–18 and 2019–20



Source: AER analysis using NEM data.

Note: The PST-2 for South Australia tests AGL Energy and Engie. Figure shows the proportion of demand that can be met by other generation (y-axis) and the corresponding level of demand (x-axis) for every hour in the 2017–18 and 2019–20 financial years. Ownership is determined using ownership declared to AEMO for each unit (DUID). Where an intermediary operates on behalf of the owner, the ownership of that DUID is attributed to the intermediary. Figure presents outcomes in NEM time (i.e. Australian Eastern Standard Time).

3.5 A participant may have incentives to not exercise market power

A participant with the ability to exercise market power may have incentives to not exercise that market power. The extent to which a participant is exposed to spot prices, and the influence of government intervention or direction affects how participants behave in the market.

3.5.1 Contracting enables participants to manage price risk

Vertical integration (section 3.1.3) and contracting (section 3.6) change 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 (box 4.1).

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 such a participant may 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, eroding any potential profit. 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.

While vertical integration continues to be a feature of the NEM, the incentives vertically integrated participants face vary depending on their portfolio.

If a vertically integrated participant is otherwise uncontracted it may face different incentives depending on how much generation it controls against its retail load. A participant with a balanced portfolio would unlikely profit from raising spot prices because any additional revenue in its wholesale business would be offset by higher costs in its retail arm. However, a participant who has more generation may be able to profit from raising spot prices as the additional revenue earned in its wholesale business would be only partly offset by increased retail costs.

The extent to which a participant is vertically integrated provides a natural hedge against spot price volatility and will influence its hedging strategies, but it is unlikely to be the only tool participants would use to reduce exposure to spot prices.

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 to which participants are vertically integrated, we do not have access to information on their contract positions. The ACCC and Australian Energy Market Commission (AEMC) have made recommendations to improve transparency for over the counter (OTC) transactions.[32 33]

3.5.2 Government direction or regulation can influence participants' behaviour

In addition to a participant's exposure to spot prices, government direction and regulation can also influence behaviour. In Queensland and Tasmania, government intervention has affected the behaviour of state-owned participants.

In Tasmania, Hydro Tasmania controls all generation capacity (section 3.1). Since 2014, the Tasmanian government has required Hydro Tasmania to offer wholesale contracts to retailers at regulated prices (box 3.4). Currently, the regulated contract price is linked to the Victorian contract price, as a competitive price. This arrangement limits Hydro Tasmania's incentive to exercise market power to increase wholesale prices in the Tasmanian market because it must still meet obligations under regulated contracts.

Box 3.4 Regulated contract pricing arrangement in Tasmania

In 2014, the Tasmanian government started regulating wholesale electricity contracts as a mechanism to reduce Hydro Tasmania's incentive to exercise market power to increase prices.

The Wholesale Contract Regulatory Instrument (WCRI) requires that Hydro Tasmania provides Tasmanian retailers access to regulated contracts at prices linked to ASX-traded Victorian electricity futures contract prices.

The WCRI is determined by the Office of the Tasmanian Economic Regulator (OTTER). Since 2014, OTTER has periodically published updates to the WCRI, most recently in September 2019 to accommodate the introduction of 5 minute settlement in the wholesale market.

In 2019, the Tasmania government commenced a review into the Tasmanian wholesale electricity market regulatory pricing framework in response to elevated wholesale prices in Victoria being no longer reflective of what they considered to be the cost of generation in Tasmania.[34] A consultation paper was released in November 2020 broadly outlining the preferred option, which includes continuing the WCRI and expanding the scope to capture non-major industrial customer load.

In Queensland, the market is also highly concentrated across the government owned participants CS Energy, Stanwell Corporation and CleanCo (section 3.1.1). In mid-2017, the Queensland government issued directions to Stanwell Corporation to 'alter its bidding strategies to help put as much downward pressure on wholesale electricity prices as possible'.[35] As a result, Stanwell Corporation changed the behaviour that had led to higher prices in previous years (section 4.1.2). This direction was removed on 30 June 2019, ahead of the transfer of generation assets from CS Energy and Stanwell Corporation to CleanCo.[36] With its establishment, CleanCo was given a mandate to increase competition at peak demand times when prices are at their highest.[37] This has contributed to lower priced offers in Queensland (section 4.1.3).

32 Recommendation 6. ACCC, *Retail electricity pricing inquiry—Final report*, 11 July 2018, p. xviii.

33 AEMC, *Market making arrangements in the NEM—Final report*, rule change, 19 September 2019.

34 Department of Treasury and Finance, *Review of the Tasmanian Wholesale Electricity Market Regulatory Pricing Framework*, Tasmanian Government.

35 Department of Resources, *Stabilising electricity prices for Queensland consumers* [PDF 1.2MB], Queensland Government.

36 State Development, Natural Resources and Agricultural Industry Development Committee, *Transcript of Estimates Hearing* [PDF 825KB], Queensland Government, 24 July 2019.

37 CleanCo, *2018–19 Annual report*, August 2019.

3.6 Liquid contract markets support an efficient market

The NEM was designed with a contract market operating in conjunction with the spot market, to enable participants to efficiently hedge against price volatility and underpin investment signals (box 3.5). To enable participants to easily buy and sell contracts to manage their risk, contract markets must be liquid.

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. Activity in OTC markets is confidential and not disclosed publicly. The Australian Financial Markets Association (AFMA) reports data on OTC markets through voluntary surveys of market participants, providing some information on the trade of standard OTC products such as swaps, caps and options. However, as it is a survey of selected participants it is not clear what proportion of trades it covers.

Box 3.5 Contract markets in the NEM

Prices in the wholesale market can be volatile, rising as high as $15,000 per megawatt hour (MWh) or falling as low as -$1,000 per MWh, which poses risks for market participants. Generators face the risk of low settlement prices reducing their earnings, while retailers risk paying high wholesale prices that they cannot pass on to their customers. Contract (futures or derivatives) markets operate parallel to the wholesale market. Most market participants use contract markets to manage at least some of their exposure to price risk. Contract prices also tend to reflect market expectations of future wholesale prices.

The wholesale electricity market is supported by 2 distinct financial markets:

- **over the counter (OTC) markets**—2 parties contract with each other directly (often assisted by a broker). The terms of OTC trades are usually set out in International Swaps and Derivatives Association (ISDA) agreements.
- **exchange traded**—electricity futures products are traded on the Australian Securities Exchange (ASX). Electricity futures products are available for Queensland, NSW, Victoria and South Australia.

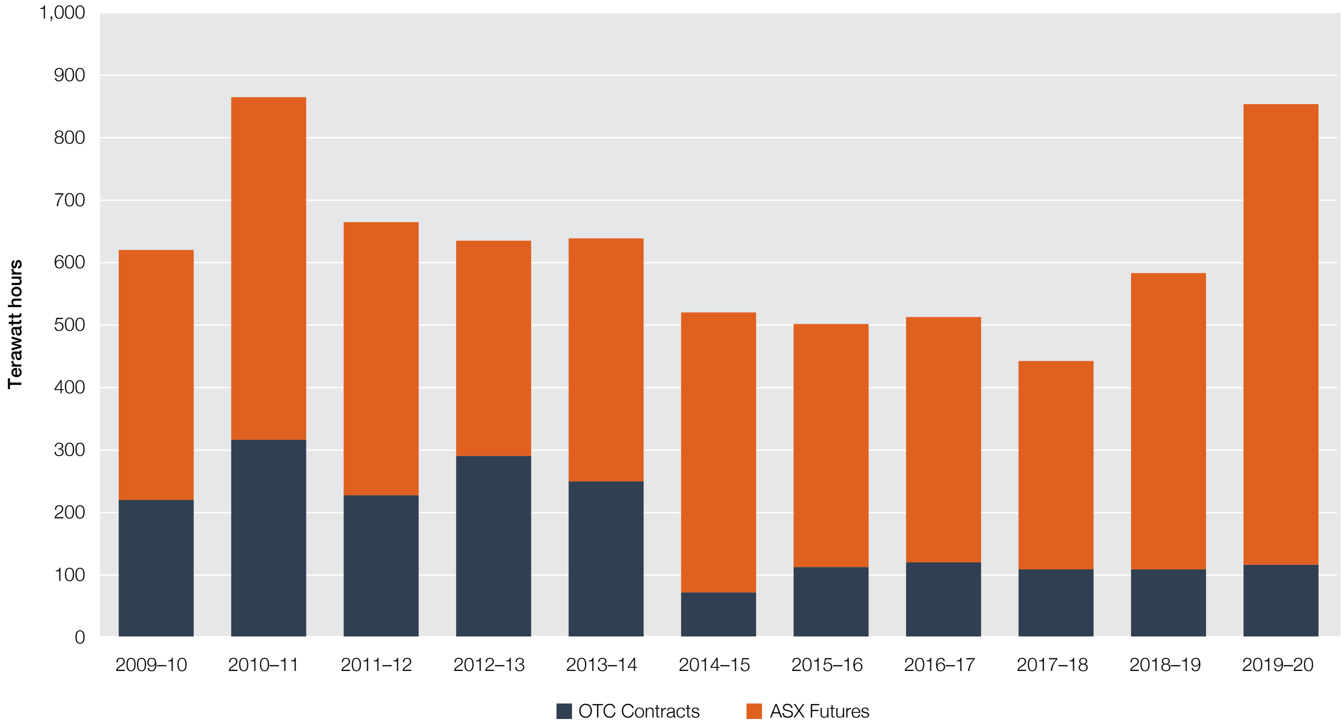
Various products are traded in electricity contract markets. Similar products are available in each market, but the names of the instruments differ. ASX Energy products are standardised to encourage liquidity, while OTC products can be uniquely sculpted to suit the requirements of the counterparties. There are a number of products typically traded:

- ASX Energy futures contracts allow a party to lock in a fixed price (strike price) to buy or sell a given quantity of electricity at 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 monthly or as calendar or financial year strips covering all 4 quarters of a year. Futures contracts are settled against the average quarterly spot price in the relevant region—that is, when the spot price exceeds the strike price, the seller of the contract pays the purchaser the difference, and when the spot price is lower than the strike price, the purchaser pays the seller the difference. In OTC markets, futures are known as swaps or contracts for difference.
- Caps are contracts setting an upper limit on the price that a holder will pay for electricity in the future. Cap contracts on the ASX have a strike price of $300 per MWh. When the spot price exceeds the strike price, the seller of the cap (typically a generator) must pay the buyer (typically a retailer) the difference between the strike price and the spot price. Alternative (higher or lower) strike prices are available in the OTC market.
- Options are contracts that give 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. An option can be either a call option (giving the holder the right to buy the underlying financial product) or a put option (giving the holder the right to sell the underlying financial product). Options are available on futures and cap products.

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

While the lack of publicly available information makes it challenging to analyse developments in contract markets in detail, ASX activity shows that traded volumes have increased significantly. In 2019–20, the volume of contracts traded were nearly double that of 2017–18. Trade volumes of ASX Energy futures in 2019–20 were also the highest on record for a financial year (figure 3.12).

Figure 3.12 Traded volumes in electricity futures contracts



Source: AER analysis using AFMA *Electricity Derivatives Turnover Report 2019–20*.

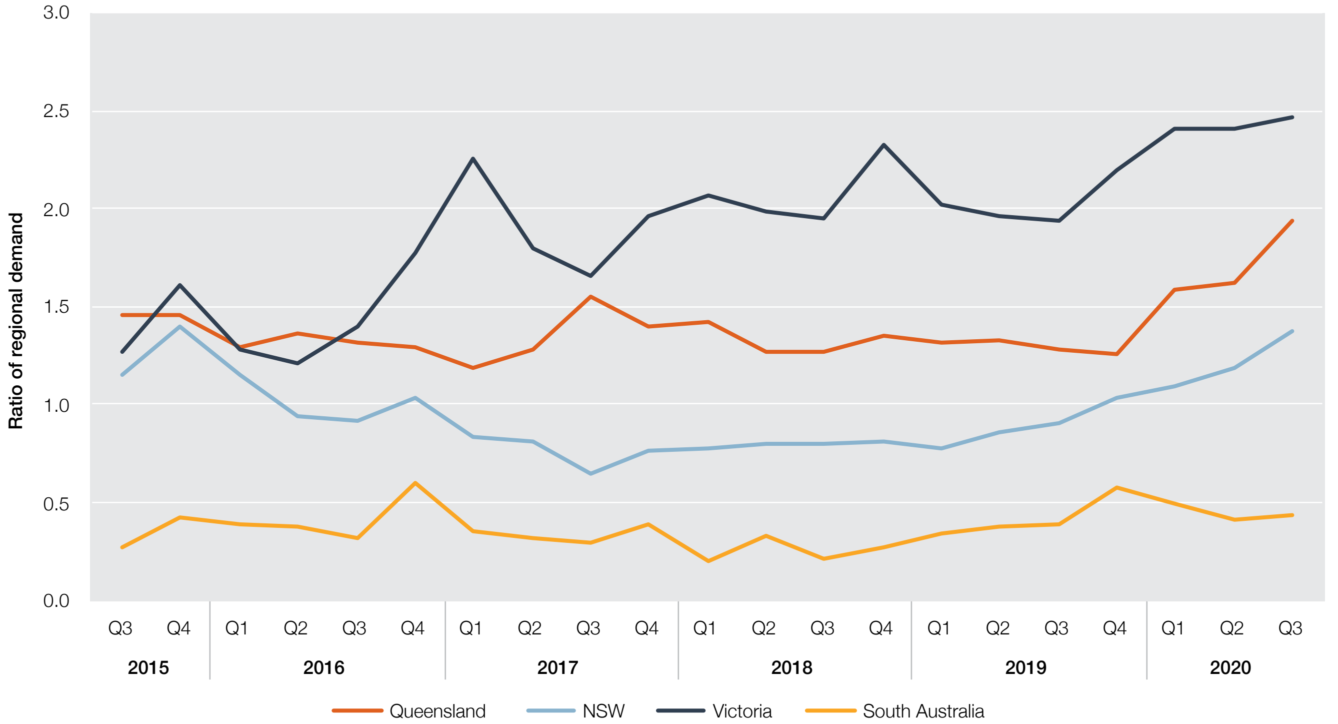
Note: Volume of trades that occurred during the financial year across all ASX Energy futures and AFMA survey data of OTC markets.

The ASX facilitates the majority of traded volumes, and base futures are the most traded contract on the ASX accounting for more than 50% of trades in 2019–20. Base futures trade volumes have continued to increase since 2017–18, improving liquidity across all regions. In 2018–19, there was more than 2 MW of contracts traded on the ASX for every 1 MW of demand. This increased further in 2019–20 with nearly 3 times NEM demand traded on the ASX, the highest level in the past 5 years.

However, while liquidity has improved in most regions, it remains significantly lower in South Australia (figure 3.13). Stakeholders noted that the Retailer Reliability Obligation market liquidity obligation had improved liquidity in South Australia but is likely to remain low due to the high penetration of intermittent generation requiring more bespoke contracts that can only be purchased OTC.[38]

38 AER, *Market Liquidity Obligation*, AER website.

Figure 3.13 ASX base futures liquidity ratio

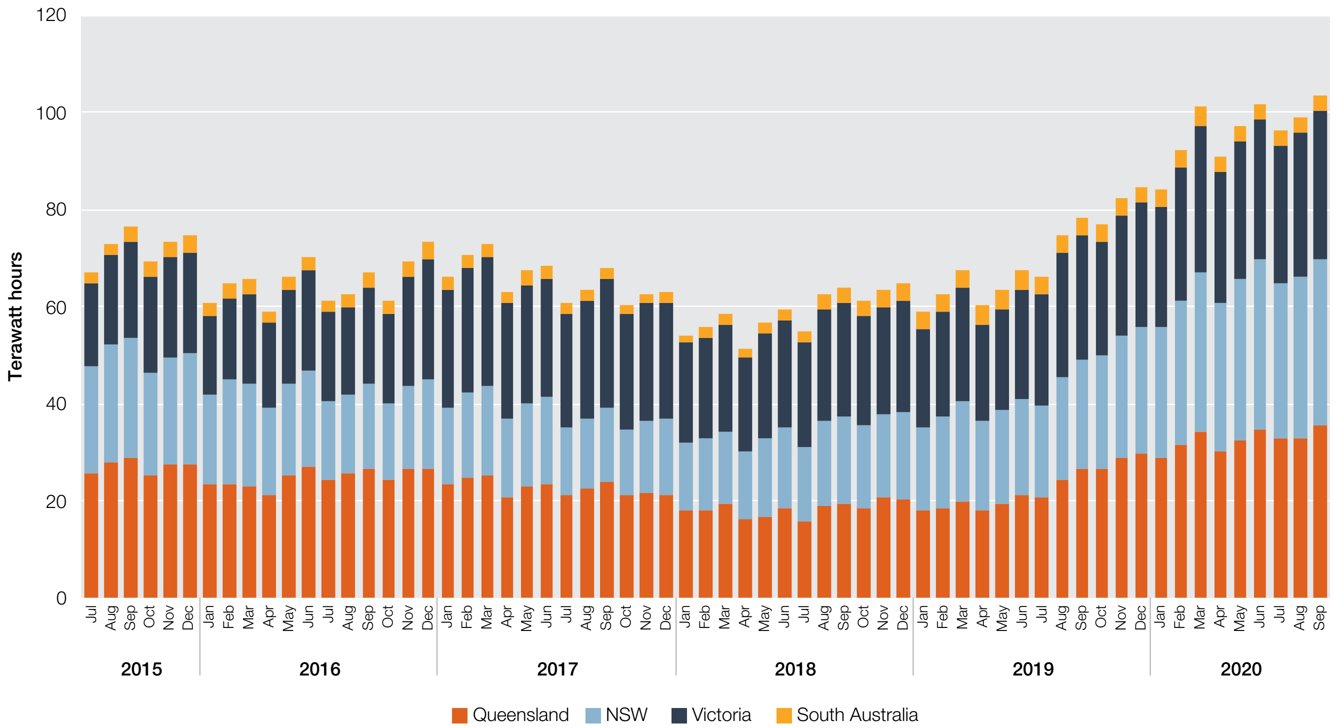


Source: AER analysis using ASX Energy data.

Note: Simple liquidity ratio uses total base futures traded for a particular quarter and the corresponding level of demand for that quarter by each region of the NEM. Tasmania has regulated contracts that are not ASX-traded.

Open interest for ASX base futures has significantly increased since mid-2019, particularly in NSW and Queensland, to more than 100 terawatt hours at the end of September 2020 (figure 3.14). Open interest indicates how many open contracts are being held by market participants on the ASX at a point in time. While higher liquidity due to increased trade volumes indicate more trading is taking place, higher levels of open interest indicates more contracts are available for trade and being held to the end of the contract.

Figure 3.14 Monthly open interest



Source: AER analysis using ASX Energy data.

Note: Open interest uses base futures open interest at the month's end for each region of the NEM. Tasmania has regulated contracts that are not ASX-traded.

3.7 There is little market based demand response but its influence may grow

Demand response refers to demand side participants increasing or reducing consumption in response to wholesale prices. 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. If participants are willing to reduce consumption in response to higher prices, this acts as a competitive constraint and can potentially limit the ability for participants to exercise market power.

Recent reforms have allowed demand response providers to offer services in frequency control ancillary services (FCAS) markets.[39] This has resulted in the entry of demand response participants to these markets from 1 July 2017, with 5 now providing FCAS in 2019–20. Due to the nature of these operations, demand response aggregators are fast and flexible and so are becoming established in contingency services markets (section 8.2).

In contrast to FCAS, participants are not able to offer demand response directly into the NEM. As a result it is managed outside the market, with energy users reducing consumption at times of high prices to limit their (or their retailer's) price exposure. However, the introduction of the wholesale demand response mechanism from October 2021 will allow demand response to participate directly in the wholesale market.[40] The Energy Security Board's (ESB) *Post 2025 market design for the National Electricity Market* (NEM 2025) also includes a longer term market development initiative to facilitate two-sided markets (section 9.3). Some stakeholders noted potential benefits of a market mechanism including:

- Increased competition in the wholesale market, through the ability for demand aggregators to offer demand response services directly, rather than via a retailer.
- A transparent indication of the value of demand response, and greater certainty about the benefit that participants will receive.

AEMO has forecast 239 MW of demand response will participate over summer 2020–21 and at times of declared reliability events, forecast demand response increases to 681 MW.[41] However, in the absence of a market mechanism, these forecasts are based on observed outcomes and some stakeholders suggested these estimates understate the true level of demand response in the NEM.

Our 2018 report highlighted that the Reliability and Emergency Reserve Trader (RERT) was crowding out potential participation in demand response.[42] Stakeholders noted that this continues to be the case, as the demand response contracted through AEMO's RERT offers a higher return than can be earned through the market for lower effort. For summer 2019–20, AEMO contracted more than 1,800 MW of reserve under RERT, much of which included demand response.[43][44]

However, the complexity of introducing a market based mechanism for generation, and the RERT potentially crowding out participation, may not result in the same uptake in energy markets as we have seen in FCAS. We will closely monitor the introduction of the wholesale demand response mechanism and its effect on competition.

39 AEMC, *Demand response mechanism and ancillary services unbundling—Final determination*, rule change, 24 November 2016.

40 AEMC, *Wholesale demand response mechanism—Final determination*, rule change, 11 June 2020.

41 AEMO, *2020 Electricity Statement of Opportunities*, 27 August 2020, p. 116.

42 AER, *Wholesale electricity market performance report 2018*, 11 December 2020, p. 35.

43 AEMO, *2019–20 NEM summer operations review report*, 22 June 2020, p. 43.

44 AEMO publishes a report whenever it contracts and activates RERT. RERT contracted reports show who the contract was with and the megawatts that participant was contracted for on a given day. These can be found on AEMO's RERT reporting page.

4. Do participants exercise market power?

Key points

- In our 2018 report rising fuel input costs contributed to higher priced offers, and we were concerned that a lack of competitive pressure allowed participants to raise offers higher than increased fuel input costs would suggest. Since then, our concerns have eased as participants returned offers to lower prices following reductions in fuel input costs, and new entry of low cost large-scale solar and wind generation is also providing competitive pressure.
- In some regions, participants are offering little capacity at prices between $50 and $500 per megawatt hour (MWh), making prices in those regions vulnerable to sudden changes in market conditions. But we did not identify a concerning exercise of market power.
- As negative prices become more common, some participants are rebidding to higher prices to avoid having to pay to generate. This behaviour will likely become more widespread if the incidence of negative prices continues to rise.
- Dynamics across the day are changing. With more generation on offer than ever before, large-scale solar is emerging as a price setter across daylight hours. In the evening peak, hydro generation is setting prices more often than it did 5 years ago.

A participant may have the ability and an incentive to exercise market power. But that does not necessarily 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 5 years to determine whether these behaviours were a sustained feature in the market and whether they contributed significantly to price increases or market volatility. We assessed longer term trends in participants' bidding conduct. We also considered intraday conduct—how participant behaviour changes across the day. In addition, we examined how participants responded to circumstances such as where a unit unexpectedly trips or a demand forecast is high.

The factors we have regard to under the National Electricity Law suggest we focus on 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 National Electricity Market (NEM) is not effective. For this reason, we focused on whether behaviour significantly affected price outcomes, and whether that behaviour was sustained.

This chapter explores the likelihood that participants exercised market power to influence 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 explores emerging changes in market dynamics across the day in response to a rising incidence of negative prices and rising levels of large-scale solar generation.

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

A range of conduct may be associated with the exercise of market power in energy markets. Participants may 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.
- 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.
- restricting the ramp rates of generation units to be dispatched in place of cheaper generation or demand response to benefit from high prices.

Participants may also reprice capacity over longer periods to higher prices, to drive average prices higher (without necessarily rebidding within the day). This activity could include shadow pricing for example, where a participant reprices capacity to just under the costs of the next highest price unit.

Some behaviours that appear to be a potential exercise of market power are, in fact, efficient responses to changing market conditions or a plant's technical requirements. For example, some rebidding can promote efficient market outcomes and benefit competition (see box 4.3).

4.1 Participants are offering more lower-priced capacity

Since our last report, the way participants offer capacity has changed across mainland regions. In our 2018 report, we observed participants shifting capacity to higher prices. Since then, offers more typically shifted down to lower prices. Coal generators are offering capacity at lower prices due to lower fuel input costs and the resolution of previously reported coal supply issues. At the same time negatively priced offers from large-scale solar and wind have become more common as a result of new entry.[45]

But the way participants are offering means less generation tends to be offered in price bands between $50 and $500 per MWh, making prices vulnerable to unexpected events, or an exercise of market power. With less intermediate priced capacity, small changes in the supply/demand balance can significantly affect price.

A number of drivers determine how participants choose to offer their capacity. Wind and large-scale solar generation, for example, generally offer into the market at prices below $0 per MWh to ensure dispatch if their intermittent fuel source is present. This then affects how other participants offer at different times of day, with some participants offering capacity at higher prices, or less capacity overall, during daylight hours. This is particularly evident in Queensland, where the most large-scale solar generation has entered the market.

This growth in low priced renewable generation capacity means the generators that set prices across the day are also changing, with more participants setting price at lower demand times of day.

4.1.1 Fuel cost and supply issues raised by NSW black coal generators in the last report have improved

On average, participants in NSW have gradually increased the amount of capacity offered into the market priced below $50 per MWh since 2018 (figure 4.1). At the same time, capacity priced between $300 to $500 per MWh has been repriced to between $150 and $300 per MWh.

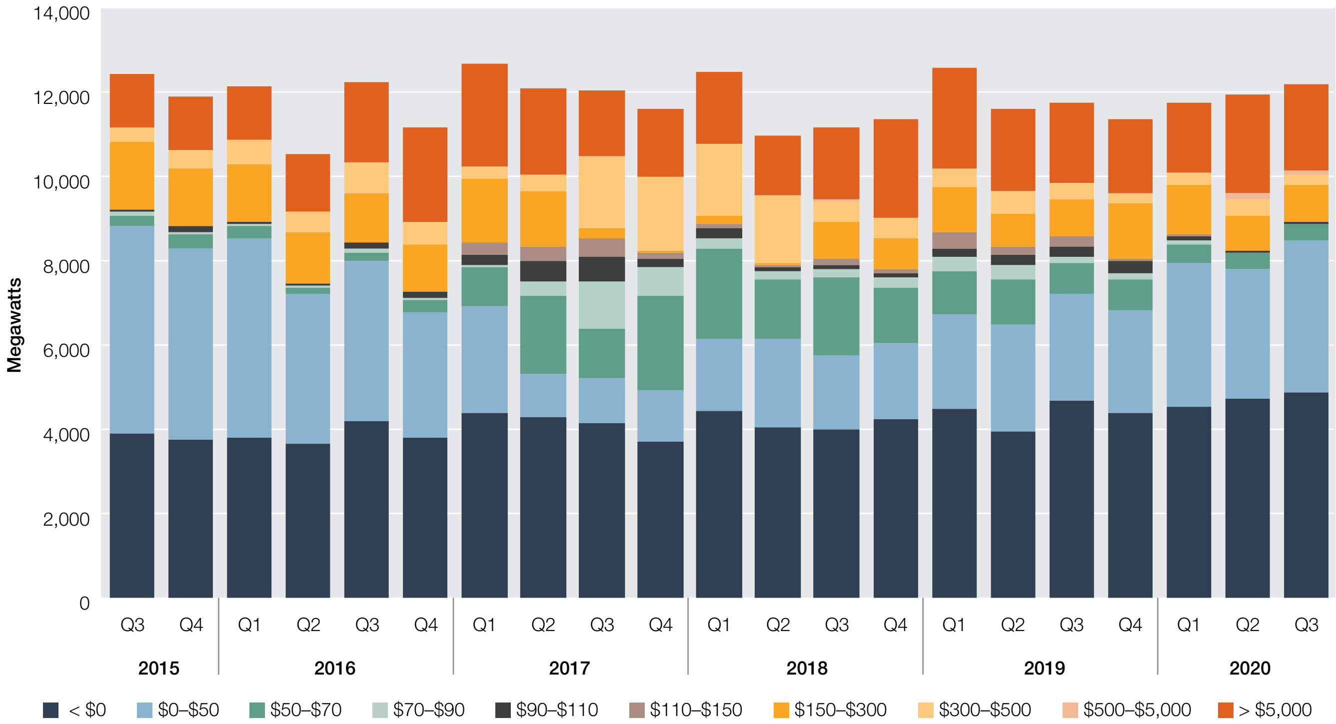
This is a reversal of our observations reported in 2018, where between 2016 and 2018, participants reduced the amount of capacity offered below $50 per MWh, and generally shifted offers to higher price bands. For example, black coal generators offered an average of 922 megwatts (MW) of capacity priced between $0 and $50 per MWh in Q3 2017, compared to nearly 3,000 MW in Q1 2020. This was the highest amount of capacity offered at those prices since Q3 2016.

45 Participants can offer capacity at negative prices to a floor of -$1,000 per MWh (box 2.1). As AEMO dispatches generators using cheapest-priced offers first, offering at negative prices is a strategy participants use to ensure dispatch.

In addition, average capacity offered at negative prices has gradually increased in recent years, reflecting lower priced offers from coal generators and new entry by wind and large-scale solar generation capacity. From Q3 2018 to Q3 2020, negatively priced offers by black coal generators increased on average from around 3,450 MW to over 4,100 MW. Over that period, negatively priced offers from wind and large-scale solar generators rose by around 400 MW.

While average offer prices have come down in recent years, participants are still offering more capacity at prices greater than $5,000 per MWh than they did in 2015.

Figure 4.1 Average quarterly offers by price bands, NSW



Source: AER analysis using NEM data.

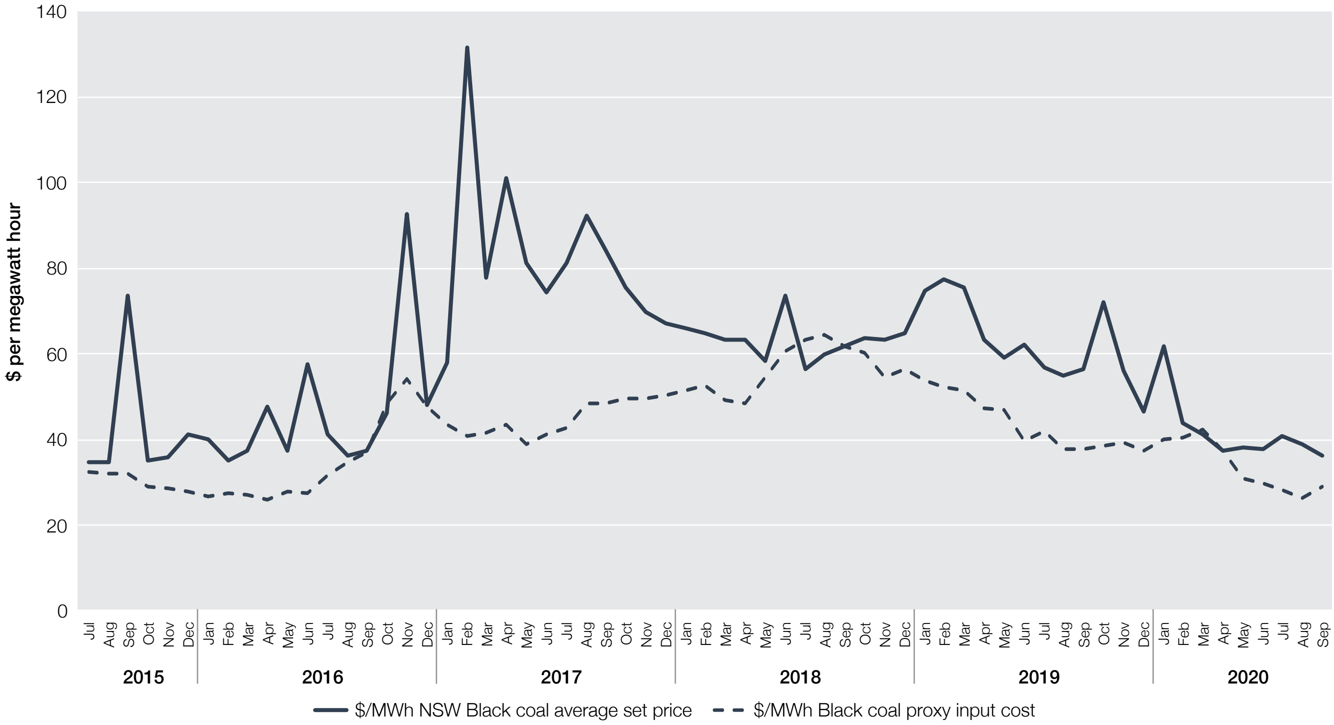
Note: Quarterly average offered capacity by NSW generators within price bands.

From 2016, participants offered more capacity at higher prices partly due to increases in the international spot price for thermal coal in Newcastle. While participants do not pay this price for all of their supply, the international price can be an important factor shaping prices when short term contracts and long term contracts are renegotiated. In the absence of public information regarding generators' individual fuel costs or contract position, this international price generally reflects a generator's theoretical *maximum* marginal cost of coal.

Our 2018 report noted concerns that black coal generators had increased their offer prices beyond levels explained by rises in international coal prices. From late 2016 to early 2018, the prices set by black coal generators diverged significantly from the international cost of coal, but converged later in 2018 (figure 4.2). The reasons for this divergence included coal supply issues and stockpile management.

Since then, NSW black coal generators set prices at lower levels, reflecting a reduction in the international coal price. In addition, participants indicated their previously reported fuel supply issues had improved. This is evidenced by a reduction in the difference between the level at which coal generators were setting prices and the international cost of coal. The 2 remained separated across 2019, but by almost half the average gap in 2017, and converged again in early 2020.

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



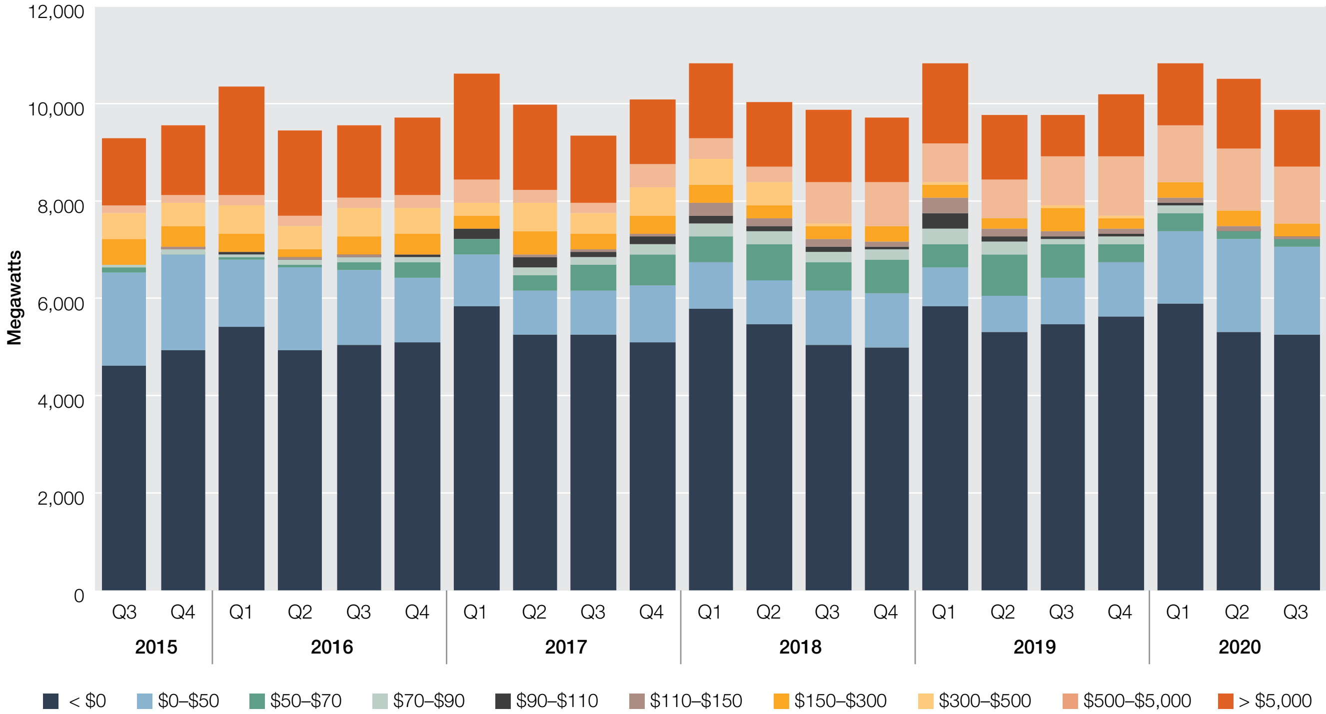
Source: AER analysis using NEM data and globalCOAL data.

Note: Black coal proxy input cost derived from Newcastle coal index (USD$ per tonne), converted to AUD$ per MWh with Reserve Bank of Australia exchange rate and the average heat rate for coal generators.

4.1.2 Queensland generators are offering more at lower prices, but the market is vulnerable to sudden changes in market conditions

Since the end of 2018, participants in Queensland have reduced the average amount of capacity offered between $50 and $150 per MWh, shifting much of it to below $50 per MWh (figure 4.3). In 2020 offers below $50 per MWh grew to over 7,000 MW on average, the highest since Q1 2017. This shift was primarily due to Queensland black coal generators shifting capacity to lower price bands. In addition, offers that were once priced between $300 and $500 per MWh have been shifted to over $500 per MWh as a result of gas generators changing their offer behaviour.

Figure 4.3 Average quarterly offers by price bands, Queensland



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by Queensland generators within price bands.

Interestingly, there is now a lack of depth in mid-priced offers in Queensland. Since early 2019, the average amount priced between $50 and $500 per MWh has decreased. In Q3 2020, less than 500 MW on average was available in this range, out of nearly 10,000 MW on offer. This meant the market was vulnerable to sudden variations in price, with small changes in demand or generator availability potentially having a significant impact. For example, on 13 October 2020, constraints limited the dispatch of some large-scale solar generators, causing over 500 MW of capacity to be unavailable. This was a key driver in the price reaching the cap for one dispatch interval, instead of a forecast price below $25 per MWh.[46]

An important factor influencing Queensland generator offers over the past few years was the Queensland government's direction to Stanwell Corporation in 2017 to put downward pressure on spot prices (section 3.5.2). This occurred following a period of price volatility, where Queensland generators took advantage of the concentrated market to rebid capacity from low to high prices from time to time.[47] After the directions were issued, there was a reduction in the incidence of rebidding causing high prices. Since the directions were removed in 2019 we have not observed a return of the price volatility (section 4.2).

Apart from the recent removal of offers priced between $300 and $500 per MWh, the general offer profile in Queensland has been similar to that of NSW since 2016. Both regions have a similar generation mix, with black coal being the major fuel source. Typically across the NEM, black coal generation competes between low cost brown coal and renewable generators, and higher cost gas generation.

However, Queensland and NSW generators source their black coal differently. When NSW black coal generators faced fuel supply issues and cost increases, Queensland black coal generators were not affected in the same way. The Australian Competition and Consumer Commission (ACCC) found between 2015 and early 2018 the cost of black coal in NSW increased by 73%.[48] Yet over the same period, the cost of black coal in Queensland declined by 5%.

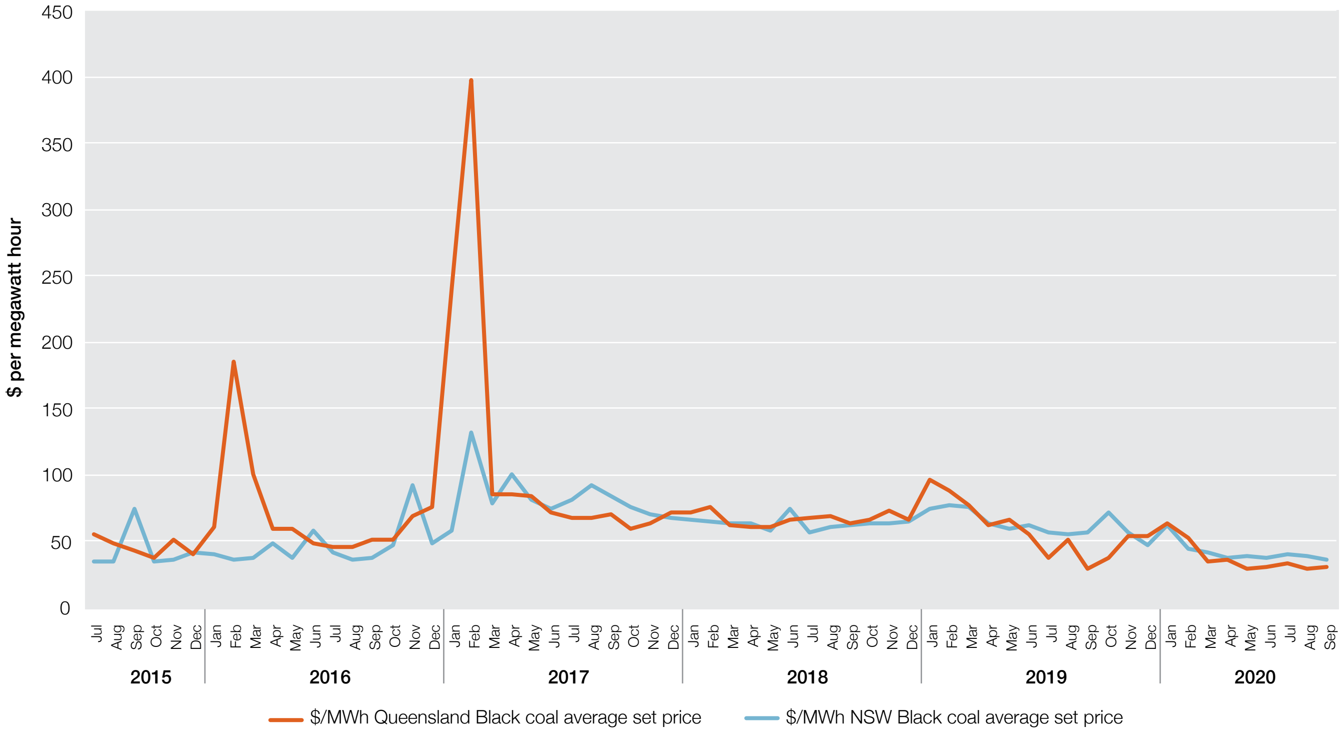
Despite not being affected in the same way, offers from Queensland black coal generators rose across 2017 and 2018 in a similar manner to those from NSW generators. As a result, as NSW black coal generators set the price at higher levels, so too did Queensland black coal generators (figure 4.4). This similarity is consistent with Queensland black coal participants shadow pricing their closest competitors by offering in at, or just below, prices offered by NSW black coal participants. While this behaviour is rational, it may indicate a lack of competitive pressure in Queensland. With more effective competition, we would expect Queensland generators to have set their prices at lower levels than their NSW counterparts across 2017 and 2018, reflecting their lower costs.

46 AER, *11–17 October 2020 electricity weekly report*, 4 November 2020, p. 8.

47 AER, *Wholesale electricity market performance report 2018*, 11 December 2018, p. 46.

48 ACCC, *Retail electricity pricing inquiry—Final report*, 11 July 2018, p. 67.

Figure 4.4 Average monthly price when Queensland and NSW black coal generators were setting the price



Source: AER analysis using NEM data.

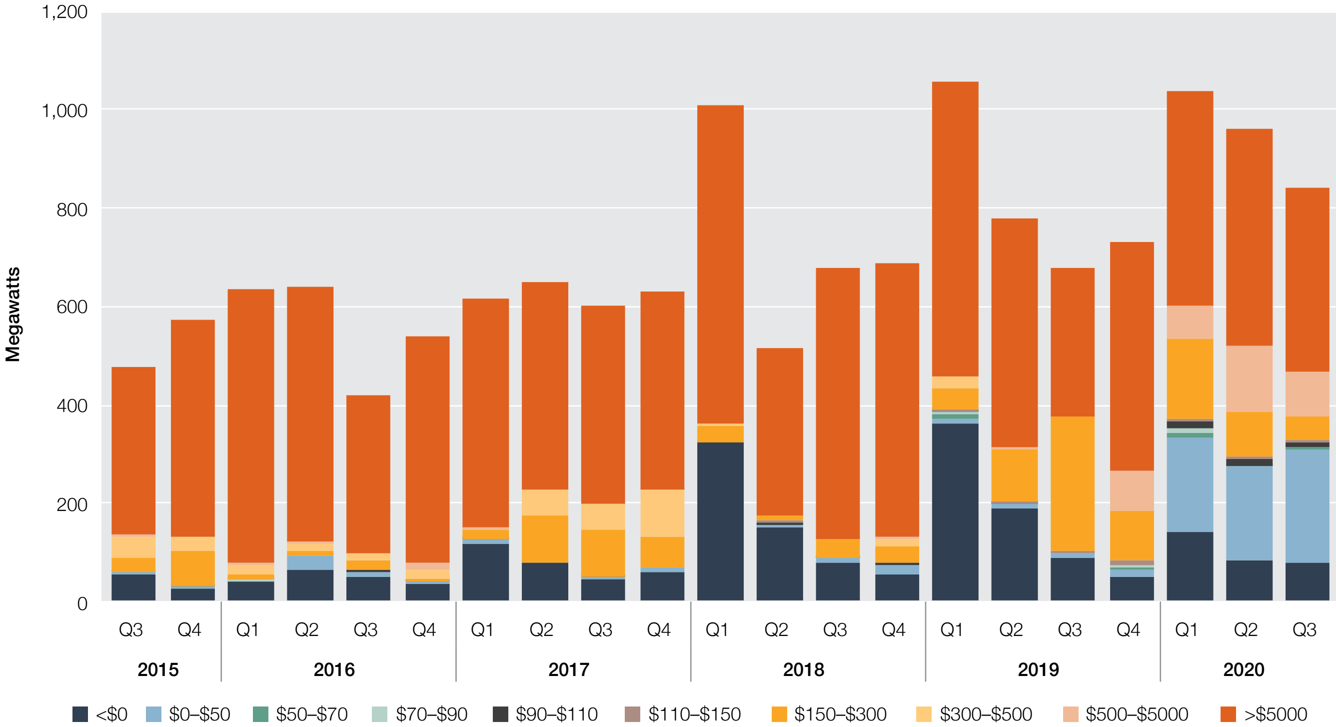
Note: Price shown is the average monthly price set by Queensland and NSW black coal generation in their respective regions.

Since our last report, this behaviour has generally continued despite broader falls in fuel costs and spot prices. The price set by the 2 regions' black coal generators significantly diverged twice in late 2019. Since then, the prices remain close, with Queensland black coal generators consistently setting price just below their NSW counterparts.

4.1.3 The creation of CleanCo resulted in some lower priced offers in Queensland

In December 2018, the Queensland Government established CleanCo as a third government owned generator in the region. On 31 October 2019, it assumed control of various generation assets previously operated by Stanwell Corporation and CS Energy, including Swanbank E gas-fired power station and Wivenhoe pumped hydro energy storage. Since then, CleanCo made additional capacity available from these generators and at lower prices (figure 4.5).

Figure 4.5 Consolidated average quarterly offers by price bands of CleanCo generation assets



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by CleanCo scheduled generation assets (Barron Gorge, Kareeya, Swanbank E, and Wivenhoe) within price bands. Prior to 31 October 2019, these generators were operated by Stanwell Corporation and CS Energy.

The most significant change in how CleanCo offers its generation was at Swanbank E power station, previously operated by Stanwell Corporation. After mothballing Swanbank E in 2014, Stanwell Corporation in 2017 announced the generator's return to service as part of the Queensland government's plan to place downward pressure on electricity prices.[49] In accordance with this, Stanwell Corporation offered Swanbank E in over the summer peak periods, and mostly at negative prices to guarantee generation.

Since CleanCo assumed operation, it made Swanbank E available beyond just the summer periods—across 2020 the amount of average capacity offered to the market remained relatively constant. In addition, it is being consistently offered at low prices, with almost all capacity priced below $50 per MWh.

Swanbank E aside, CleanCo's remaining assets are hydro generators. Reflecting the impact of water availability on these technologies, their low priced offers have not changed significantly. However some generation previously priced above $5,000 per MWh was moved to between $150 and $5,000 per MWh.

4.1.4 Lower priced offers by brown coal generators are driving negative priced offers in Victoria

Following Hazelwood power station's closure in early 2017, average capacity in Victoria offered at negative prices fell.[50] Following this initial drop, capacity priced below $0 per MWh has since increased, returning in 2020 to levels similar to those before Hazelwood's closure (figure 4.6). This return is partly due to brown coal generators progressively shifting about 800 MW of capacity on average from prices greater than $0 per MWh to negative prices. And from Q2 2017 to Q2 2020, negatively priced capacity offered by wind and large-scale solar generators grew by over 400 MW.

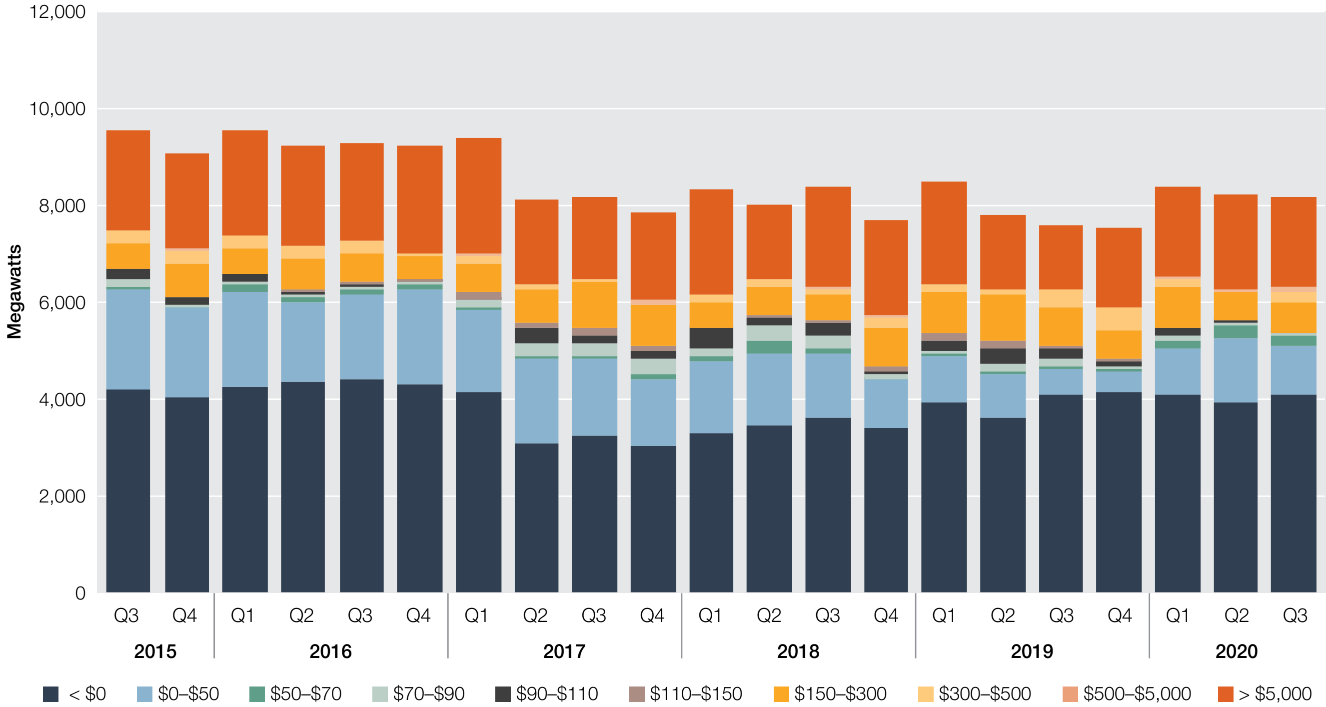
But, capacity offered between $0 and $50 per MWh has decreased over this period, and the overall volume of low priced capacity remains well below the levels seen before Hazelwood's closure. As a result, Victorian prices remained above historic levels across this period, before easing in recent quarters.[51]

49 Stanwell Corporation, *Swanbank E Power Station to return to service* [media release], 7 June 2017.

50 Our *Hazelwood advice* provides greater detail and analysis the closure of Hazelwood power station and its impacts.

51 AER, *Wholesale markets quarterly—Q3 2020*, 12 November 2020, p. 4.

Figure 4.6 Average quarterly offers by price bands, Victoria



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by Victoria generators within price bands.

4.1.5 Lower gas prices and new entry result in more low priced capacity in South Australia, but the market is susceptible to price volatility

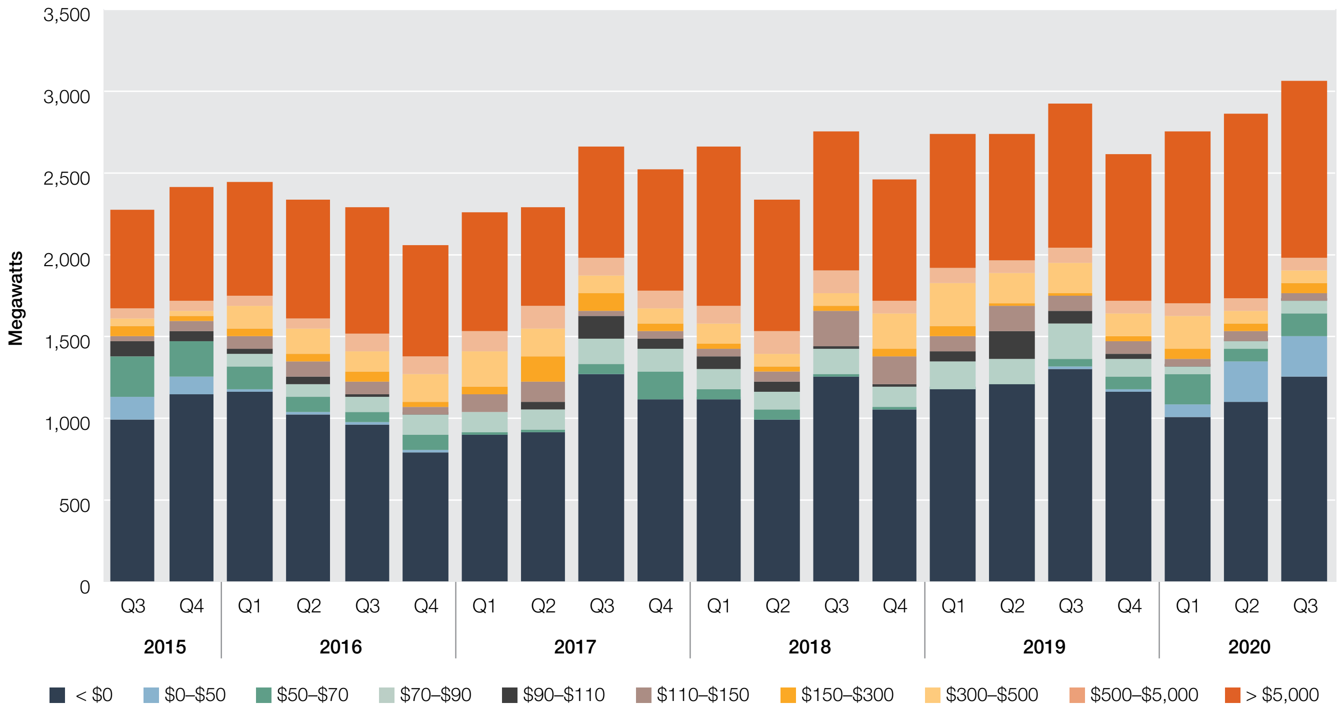
Since 2016, total capacity offered into South Australia increased as over 1,600 MW of new generation entered the market, the majority of it wind and large-scale solar (figure 4.7). As a result, most of this new capacity has been offered in at negative prices. However, the changing generation mix has led to a market with little capacity priced between $50 and $300 per MWh, that is vulnerable to small changes in demand or availability.

Northern power station closed in Q1 2016, from which time offers in South Australia priced below $70 per MWh began falling. At the same time, across 2016 and 2017 input costs for gas generation increased, which resulted in more capacity offered in at prices greater than $70 per MWh.

As fuel input costs eased more recently, gas generators made more capacity available in the $0 to $70 per MWh range. This coincided with the entry of Barker Inlet power station into the market, which replaced the older Torrens Island A power station. The new generator began offering capacity in the $0 to $70 per MWh range. In response, other generators shifted some capacity to similar prices.

But at the same time, higher-cost gas generators have offered increasing amounts at prices greater than $300 per MWh. This coincided with rising wind and large-scale solar generation and some gas generators operating less often. As those generators have fewer hours of operation to recover costs, they may have incentives to offer capacity at higher prices to compensate.

Figure 4.7 Average quarterly offers by price bands, South Australia



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by South Australia generators within price bands.

4.1.6 Changes in offers in Tasmania driven by physical issues and weather

The Tasmanian Government-owned Hydro Tasmania controls all generation in Tasmania.[52] The majority of its portfolio consists of hydroelectric generation, supplemented by wind and gas-fired generation. Hydro Tasmania's position in the market means the way it offers its capacity determines prices in the region. However, the price at which Hydro Tasmania may offer wholesale contracts is regulated, which may limit its opportunities to exercise market power (box 3.4).

Tasmanian prices generally follow similar trends to those in other regions (section 2.1). However, whether the offers that determine prices are efficient is difficult to assess. In particular, offers of hydroelectric generation can change significantly depending on the marginal value of water used. As the fuel source for hydroelectric generation has no market value, the value of water is calculated on opportunity cost factors such as dam levels, forecast rainfall, and interconnector availability. As this value is artificially determined, there is uncertainty around the true efficient cost of production—and in turn, price—for hydroelectric generators.

The structure of Tasmanian offers typically follow a cyclical pattern based on the season (figure 4.8). Tasmania as a region stands separate from the rest of the NEM in that it experiences peak demand over winter rather than summer, as a result of cold temperatures driving heating demand. The greatest volume of low priced capacity tends to be offered over the colder winter months, and the least low priced capacity offered in the warmer months.

In the past 5 years, the most negatively priced capacity, and the most capacity overall, was offered in Q3 2018. This coincided with above average rainfall across Tasmania, which contributed to dam storage levels approaching 50% in August and September. Reflecting the significant capacity offered at lower prices, Hydro Tasmania reported its highest monthly generation output to date in August 2018.[53]

Another critical factor in Tasmanian offers is the availability of the region's interconnector to the mainland—Basslink. In December 2015, an unexpected outage forced Tasmania to meet all demand from its own generation until May 2016. Reflecting this change in conditions, average offers adjusted across this period, with a reduction in capacity priced below $50 per MWh, and an increase in capacity priced between $50 and $300 per MWh.

Interestingly, this period also marked the start of a change in offer behaviour in Tasmania. Previously, the majority of capacity was offered in below $110 per MWh (with much of this below $50 per MWh) with very little offered at prices

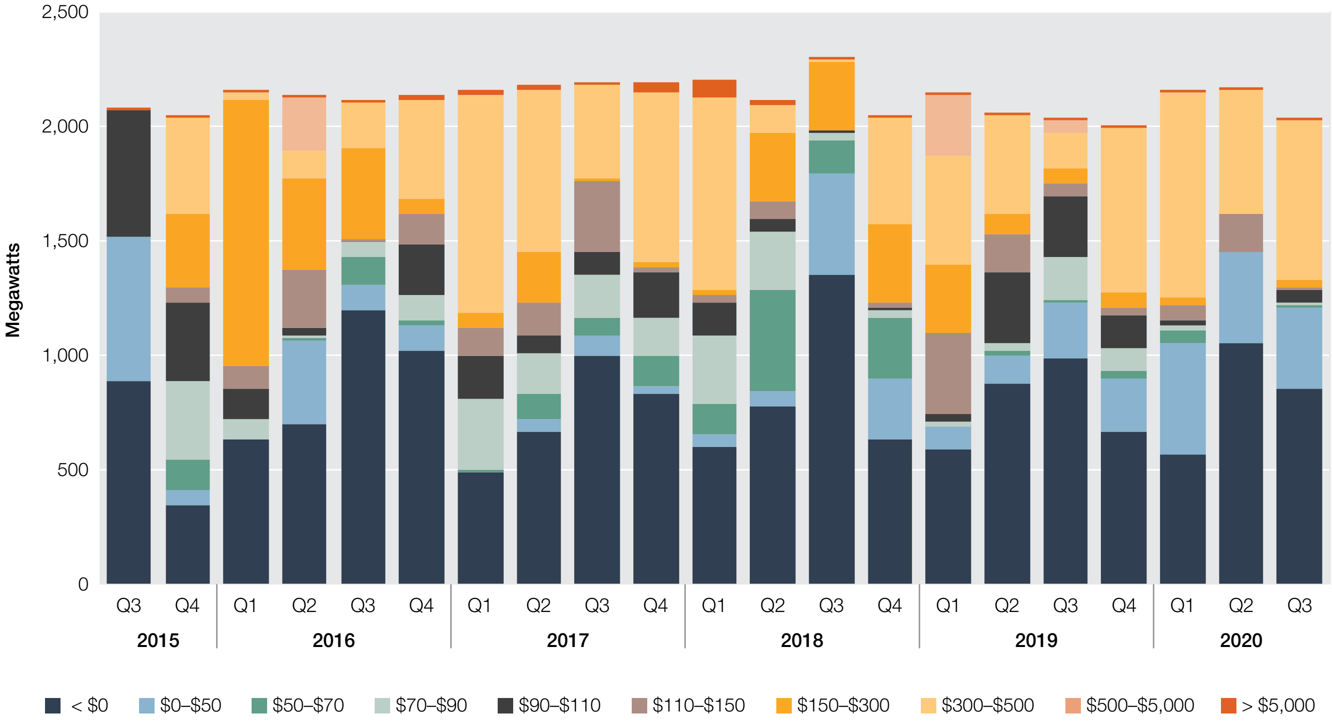
52 Hydro Tasmania has long-term offtake agreements for generation it doesn't own in Tasmania, which gives it control over the assets. Since 2018, some new generation has followed this arrangement, including the new Granville Harbour and Cattle Hill wind farms.

53 Hydro Tasmania, *Annual report 2018*, October 2018, p. 11.

greater than $300 per MWh. However, from 2016, offers generally shifted to higher prices. Capacity previously offered at prices between $90 and $110 per MWh increasingly shifted to between $300 and $500 per MWh. And capacity previously offered between $0 and $50 per MWh moved to be spread across price bands between $0 and $300 per MWh.

Further Basslink outages also changed offer behaviour in Tasmania. During an outage from March to June 2018, capacity previously offered at prices greater than $300 per MWh was shifted to lower prices. Similarly, during an outage from August to September 2019 less capacity was offered in at prices greater than $300 per MWh.

Figure 4.8 Average quarterly offers by price bands, Tasmania



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by Tasmania generators within price bands.

4.2 We did not identify the exercise of market power as a significant factor driving price spikes

Our routine weekly analysis of market outcomes provides insights into the factors contributing to price spikes. We report on why prices differ from forecast if they breach our reporting thresholds (box 4.2). Since our last report, the main factors contributing to unforecast high prices have changed. For 2019–20 the primary factors included rebidding, generator availability and inaccurate demand forecasting. Together these reasons explain more than two-thirds of unforecast high prices.

Even a small number of price spikes over $5,000 per MWh can significantly impact market outcomes (section 2.3). Therefore, it is important to review generator behaviour at these times. In the past, our investigations found generator rebidding was a primary cause of some extreme price spikes. But since our last report, generator rebidding was not the primary cause of prices spiking over $5,000 per MWh.

Box 4.2 Factors contributing to unforecast price spikes

The National Electricity Rules require the AER to analyse why prices vary from forecast and publish this information weekly. We do in-depth analysis if the spot price exceeds reporting thresholds (when spot prices are above $250 per megawatt hour (MWh) and are more than 3 times the weekly volume weighted average price) and we assign reasons why the price differed from forecast. We perform similar analysis for prices below -$100 per MWh that varied from forecast. We track reasons that contribute to spot prices varying from forecast and use these in our analysis.

Also, we must publish a report on why any spot price exceeds $5,000 per MWh, including whether rebidding contributed.

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

4.2.1 While rebidding is a common factor in prices being different to forecast, it has not been a major factor in prices spiking over $5,000 per MWh in recent years

Through our weekly analysis, we identified that rebidding contributed to 24% of unforecast high prices in 2019–20. Rebidding leading to price spikes was historically an area of concern. While, rebidding is a mechanism that promotes efficiency in dispatch and allows participants to change their offers, if misused it may also compromise competitive outcomes (box 4.3).

Box 4.3 Rebidding in the NEM

The efficient and secure operation of the National Electricity Market (NEM) depends on instantaneously matching supply and demand of electricity. 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. For example, rebidding just before dispatch 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.

Despite being a common factor in prices differing from forecast, rebidding has not been a primary factor in prices spiking above $5,000 per MWh in recent years. Since our last report, we have published 9 reports analysing energy prices greater than $5,000 per MWh. Of these, 8 were primarily caused by extreme conditions, including weather and bushfires, with the remaining event the result of significant equipment failure.

Of the 9 reports, generators rebidding capacity from low prices to high contributed to 2 events—on 4 January and 2 March 2020.[54] [55] But on 4 January 2020, this rebidding occurred after high prices had occurred and was a result

54 AER, *Prices above $5000/MWh—4 January 2020 (NSW)*, 27 February 2020.

55 AER, *Prices above $5000/MWh—2 March 2020 (South Australia)*, 29 April 2020.

of interactions between energy and FCAS. And on 2 March 2020, this rebidding occurred prior to equipment failure, which ultimately caused the high prices. On the other hand, for 4 events we found that participants rebid capacity from high prices to low prices during these extreme or unexpected events.

Most recently, in November 2020 there were 2 high price events in NSW.[56 57] As with other instances when the price rises above $5,000 per MWh, we will investigate the causes and report our findings.

Our 2018 report also identified how Queensland participants had taken advantage of a concentrated market structure to rebid large volumes of capacity from low to very high prices late in a trading interval, causing the price to spike.[58] But following an Australian Energy Market Commission (AEMC) rule change in 2015 and the Queensland Government's direction to Stanwell Corporation in 2017, price volatility has largely ceased.[59 60] Our analysis of the timing of late rebids over the past 5 years shows no significant late rebidding in any region similar to Queensland's experience from 2013 to 2016.

4.2.2 Technical issues explain price spikes caused by generator availability

Generator availability contributed to 25% of the unforecast high prices we analysed in our weekly analysis for 2019–20. The availability of generators is a contributing factor in unforecast high prices, as less capacity is available in the market to meet demand, meaning higher priced generation has to be dispatched. Deliberate withholding of capacity (physical withholding) can create artificial shortages and spike prices, which compromises market competitiveness. However, we did not identify concerning behaviour when participants changed their offers and made their generators unavailable.

The circumstances in which physical withholding is likely to be a profitable strategy are limited, as participants are only paid for the energy they generate. And, as many generators sell financial instruments to insure against the risk of high prices, participants often do not ultimately receive the market price for their energy, but rather an agreed price. Typically, rebids relating to generator availability reflect technical issues such as unplanned outages, or adjustments to prevailing conditions, rather than an exercise of market power.

4.2.3 The accuracy of demand forecasts can contribute to price spikes, but AEMO is improving its processes

In 2019–20 incorrect demand forecasts by the Australian Energy Market Operator (AEMO) contributed to 19% of unforecast price spikes identified through our weekly analysis. AEMO provides a range of short, medium and long term demand forecasts. These forecasts provide signals to participants to plan operational strategies and investment decisions. Accurate demand forecasting is important, but can be challenging. And, as consumers have increasing access to resources such as rooftop solar and residential batteries, demand forecasting becomes increasingly complex.

But inaccurate forecasts can have significant consequences for participants. Overforecasting demand might lead participants to incur fuel costs, or undertake other commitments unnecessarily in response. Similarly, underforecasting demand may leave the market short of supply because participants may not make sufficient generation available. While inaccurate forecasting can affect market outcomes, it does not represent an exercise of market power.

In recent years, AEMO has worked to improve the accuracy of its demand forecasting, both short and long term. The AEMC published its *Reliability frameworks review* in July 2018, where it recommended AEMO publish new guidelines for its forecasting methodologies.[61] Following this, AEMO integrated data from new sources as part of its forecasting approach, including consumer energy meter data, battery discharge profiles and granular weather data.[62] In addition, AEMO developed an operating procedure, whereby wind and large-scale solar generators may self-forecast their capacity.[63]

56 AER, *Wholesale electricity prices above $5000 per MWh in NSW and Frequency control ancillary service price above $5000 per MW in Queensland* [communication notice], 18 November 2020

57 AER, *Wholesale electricity prices above $5000 per MWh in NSW on 20 November 2020* [communication notice], 24 November 2020.

58 AER, *Wholesale electricity market performance report 2018*, 11 December 2018, p. 46.

59 AEMC, *Bidding in good faith—Final determination*, rule change, 10 December 2015.

60 Department of Resources, *Stabilising electricity prices for Queensland consumers* [PDF 1.2MB], Queensland Government.

61 AEMC, *Reliability frameworks review—Final report*, market review, 26 July 2018.

62 AEMO, *2019 Electricity Demand Forecasting Methodology Information Paper*, 28 February 2019.

63 AEMO, *Participant forecasting*, AEMO website.

4.3 As the generation mix changes, some participants are rebidding more to avoid negative prices, while others are offering differently across the day

Significant wind and large-scale solar capacity has entered the market in recent years, causing market dynamics to shift. Large-scale solar in particular has added generation in the middle of the day, and this capacity is setting the price more frequently at these times. The majority of large-scale solar capacity is priced negatively, and price outcomes have begun to reflect this with an increased incidence of negative prices (section 2.3). To date, this is most pronounced in Queensland and South Australia. But, as more renewable generation enters the market, this is likely to become a trend across the NEM as a whole. Most of these outcomes vary significantly from forecast.

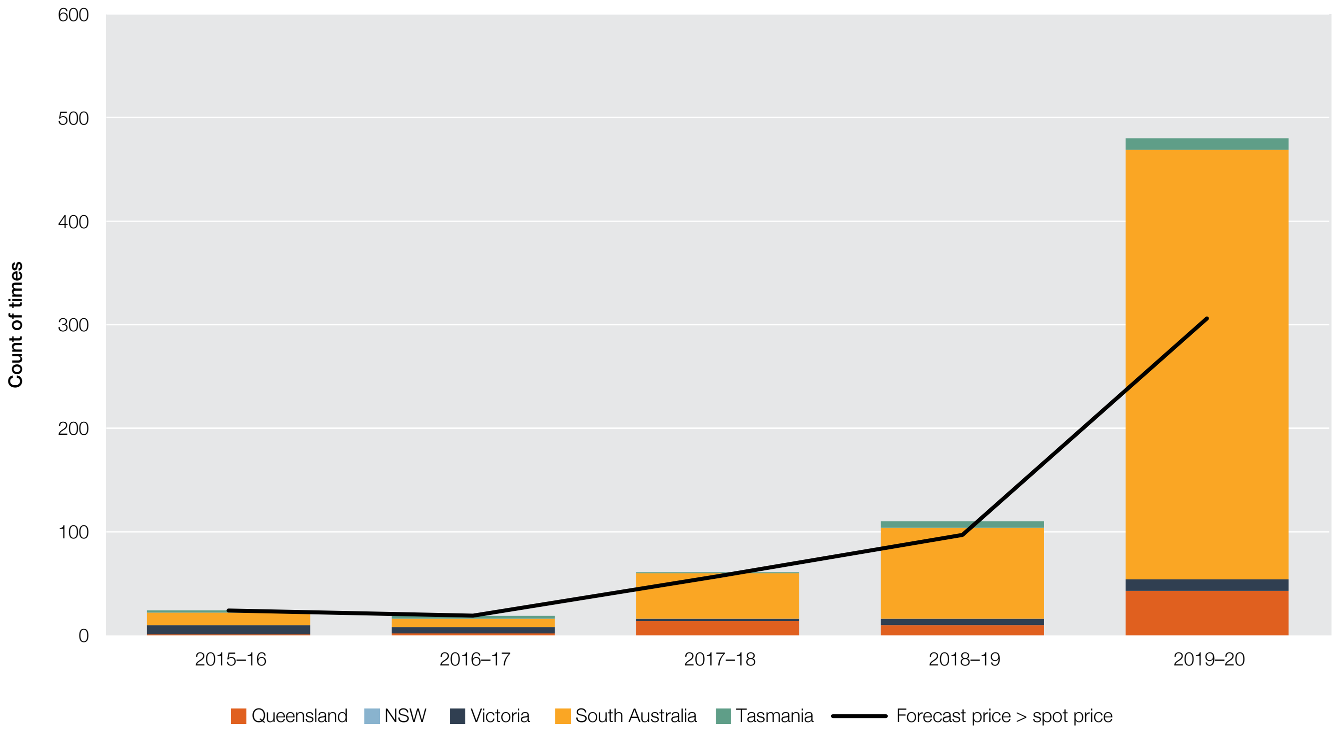
As the incidence of negative prices increase, it is becoming uneconomic for some generators to operate at those times. Intermittent renewable generators typically offer at negative prices to guarantee dispatch, partly reflecting the revenue streams they receive outside the market which make it profitable to generate even with low prices. But we have observed some renewable generators recently rebidding to higher price bands more often in response to negative prices.

In contrast to these daytime outcomes, higher priced hydro generation is setting the price more often in the evening than 5 years ago, when prices are higher.

4.3.1 There are now more unforecast prices below -$100 per MWh

The magnitude of negative prices has grown with instances of prices below -$100 per MWh increasing by more than 400% in the 2019–20 financial year (figure 4.9). At the same time, instances of unforecast prices below -$100 per MWh have also increased significantly.[64]

Figure 4.9 Count of prices below -$100 per MWh by region and where the price was lower than the 4 hour ahead forecast



Source: AER analysis using NEM data.

Note: Count of regional prices less than -$100 per MWh for each financial year. For those prices, count of times the spot price was less than the 4 hour ahead forecast price.

64 We assess reasons for significant variations between forecast and actual prices below -$100 per MWh as part of our routine weekly monitoring.

For prices below -$100 per MWh, we analyse the reasons for significant variations between forecast and spot price as part of our weekly analysis (box 4.2). Similar to when prices spike, the primary reasons include demand accuracy, generator availability and generator rebidding. However, for prices below -$100 per MWh the fluctuating availability of wind generation was another primary reason for variations from forecast. This is due to the high penetration of wind resources in some regions, particularly in South Australia. Wind generators usually offer at negative prices to be dispatched when the wind blows, but the windiness of any particular interval is challenging to accurately forecast. Often there is less, or more, wind than expected and prices can differ from forecast as a result.

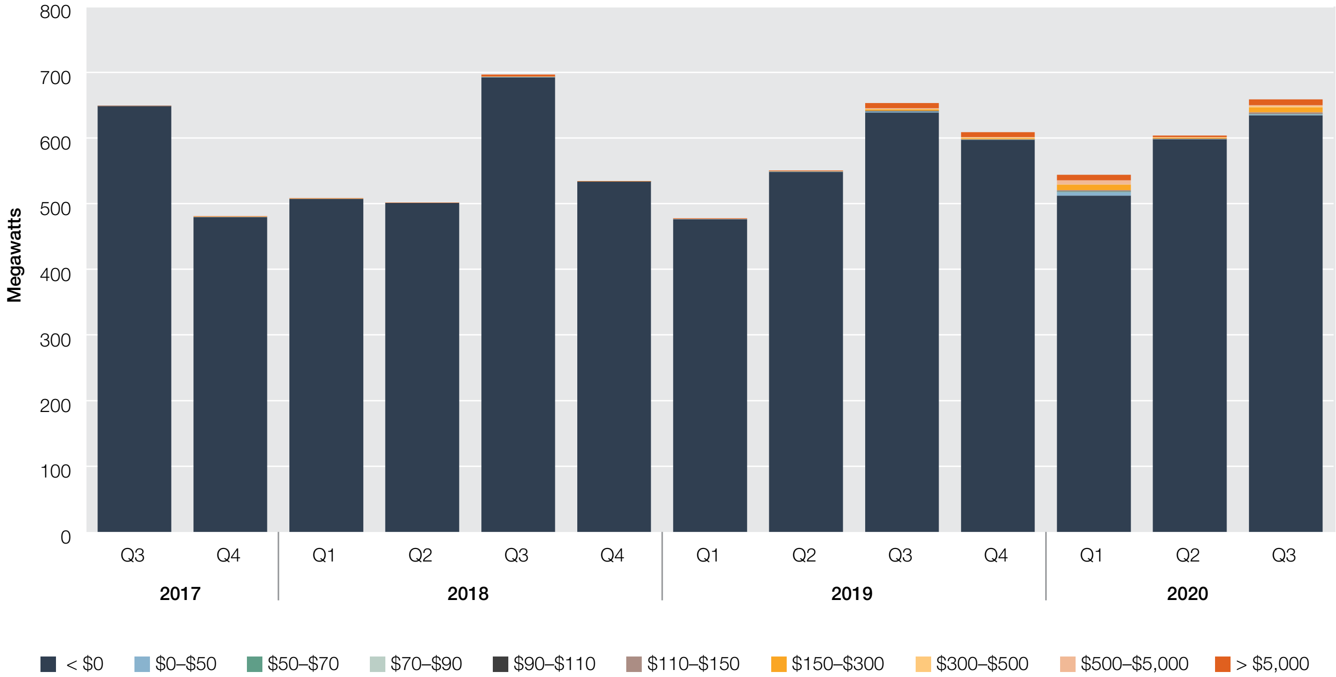
In the majority of cases where the spot price is lower than forecast, more supply was made available through unexpected additional wind generation, or participants otherwise offered more low priced capacity. In some cases, lower than expected demand driven by high rooftop solar generation also contributed. Ultimately these outcomes highlight the impact of the growth of intermittent renewable technologies, as the majority of these events occur during daylight hours.

4.3.2 Some renewable participants are rebidding to avoid negative prices

As market dynamics around negative prices change, participants are also changing how they respond to lower prices. In 2019–20, when prices were negative, or forecast to be negative, some wind and large-scale solar participants began rebidding negatively priced capacity to higher price bands to avoid paying to generate. While a relatively small portion of the capacity on offer, this appears to be an emerging trend.

In South Australia for example, wind generators continued to offer in at mostly negative prices. However, over 2019–20 they rebid capacity to higher price bands often enough for their average offers to show more capacity at prices greater than $50 per MWh than ever before (figure 4.10). Of that capacity, much was offered in at prices greater than $5,000 per MWh. These higher-priced offers were driven by how wind generators' rebid when dispatch prices fall below $0 per MWh.

Figure 4.10 Average quarterly offers by price bands, South Australia wind generators



Source: AER analysis using NEM data.

Note: Quarterly average offered capacity by South Australia wind generators within price bands.

The majority of cases where wind generators in South Australia offered capacity at higher prices occurred during daylight hours. This coincided with high output from large-scale solar which increased available low priced supply, and rooftop solar generation which reduced grid demand.

As these generators have no control over when their fuel source is available, they have typically bid at negative prices in order to guarantee dispatch when they are able to generate. This was particularly the case when non-market incentives like the Renewable Energy Target (RET) or Power Purchase Agreements would provide them with income regardless of the wholesale spot price. However, the RET incentives are now less lucrative, and in our market enquiries some participants revealed that they are now subject to contract clauses that require them to stop generating when the price goes below $0 per MWh.

In addition, some semi-scheduled participants have physically withdrawn from the market by turning their plant off at times of negative prices, rather than rebidding capacity. These unforecast changes reduce the accuracy of price forecasts, contribute to poor power system frequency performance, and increase the amount of FCAS required. The AER submitted a rule change to the AEMC in September 2020 aimed at addressing this behaviour.[65]

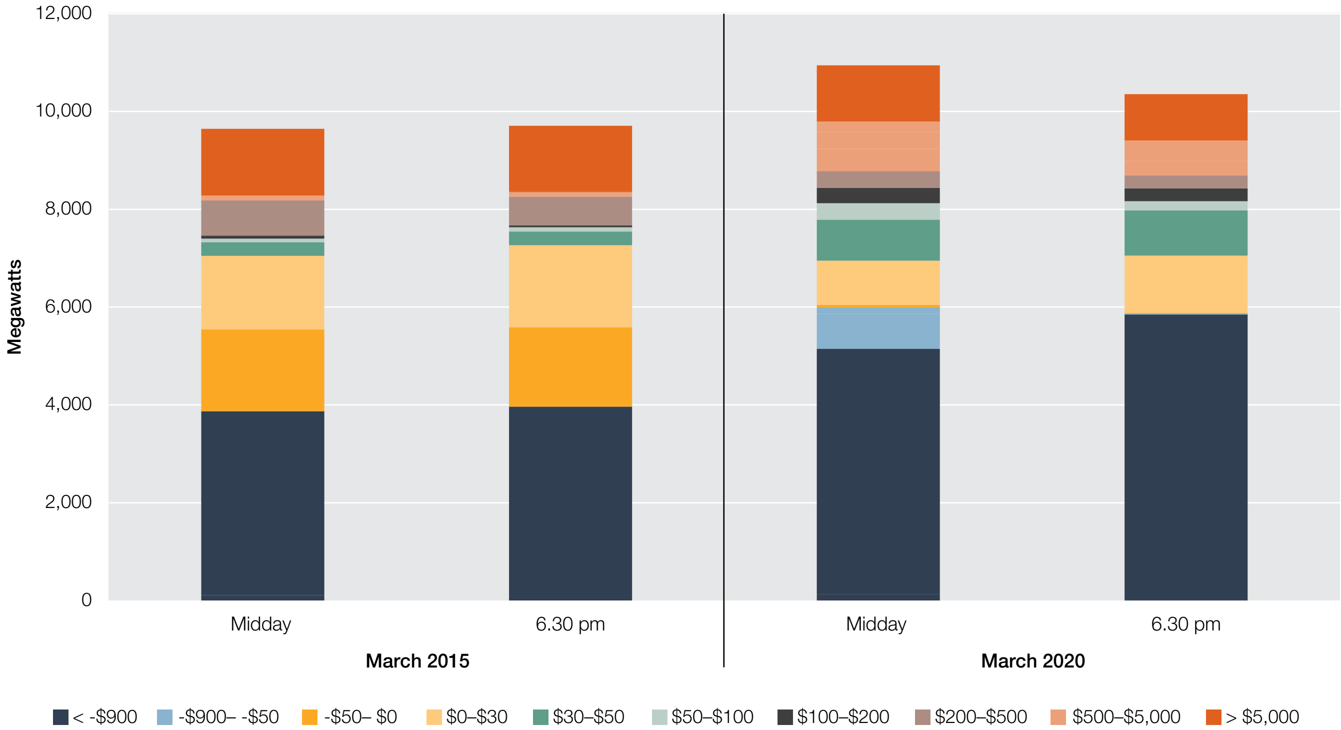
We observed some participants behaving in the opposite manner to that described, instead rebidding capacity to low prices at times of negative prices. Those participants cite 'FCAS/Energy co-optimisation' as their reason for doing so. When the price of energy falls to negative prices, participants that provide FCAS may have incentives to increase dispatch in FCAS markets where prices may be higher.[66]

4.3.3 More solar generation on offer in Queensland results in other participants offering differently by time of day

With the growth of large-scale solar generation the offer dynamics of different technologies are changing. In some cases, generators are withdrawing available capacity from the market when large-scale solar is producing, and offering it back during the evening peak. Other generators are offering capacity at higher prices in the middle of the day and at lower prices in the evening. The following are examples from Queensland where the effect is most pronounced, but similar outcomes may occur in other regions with further new entry.

In March 2015, the average amount offered by participants in Queensland, and the price bands in which it was offered, did not change significantly between the midday and 6:30pm trading intervals (figure 4.11). However in March 2020, participants were offering about 600 MW more capacity in the market at midday than at 6:30pm, partly reflecting the additional daytime contribution of large-scale solar generation. On an average day in Q1 2020, large-scale solar might offer as much as 900 MW into the Queensland market. In Q1 2015, gas generators in Queensland would offer roughly the same total capacity across the day. But now these generators are offering about 300 MW less in the middle of the day compared to the evening peak times.

Figure 4.11 Queensland average offers by price bands at midday and 6:30pm, March 2015 and March 2020



Source: AER analysis using NEM data.

Note: Monthly average offered capacity at specific times of day by Queensland generators within price bands.

65 AEMC, *Semi-scheduled generator dispatch obligation—Draft determination*, rule change, 19 November 2020.

66 We discuss how different participants' incentives influence their behaviour when the price goes negative further in our *Wholesale markets quarterly Q3 2019*.

Participants are also using the range of price bands to a greater extent than in 2015. Despite this, participants in 2020 are offering less capacity in intermediate price bands between $50 and $500 per MWh than in 2015 (section 4.2). Again, changes in offer strategies by particular generators is driving this new dynamic.

For example, in Q1 2015 Queensland black coal generators would offer the majority of their capacity at prices less than $30 per MWh and greater than $5,000 per MWh. Between morning and late evening they moved some higher priced capacity to lower bands, including about 300 MW of capacity to between $30 and $300 per MWh. After the Queensland government issued a direction to Stanwell Corporation in 2017, black coal generators moved the majority of their higher priced capacity to prices less than $300 per MWh in the evening.

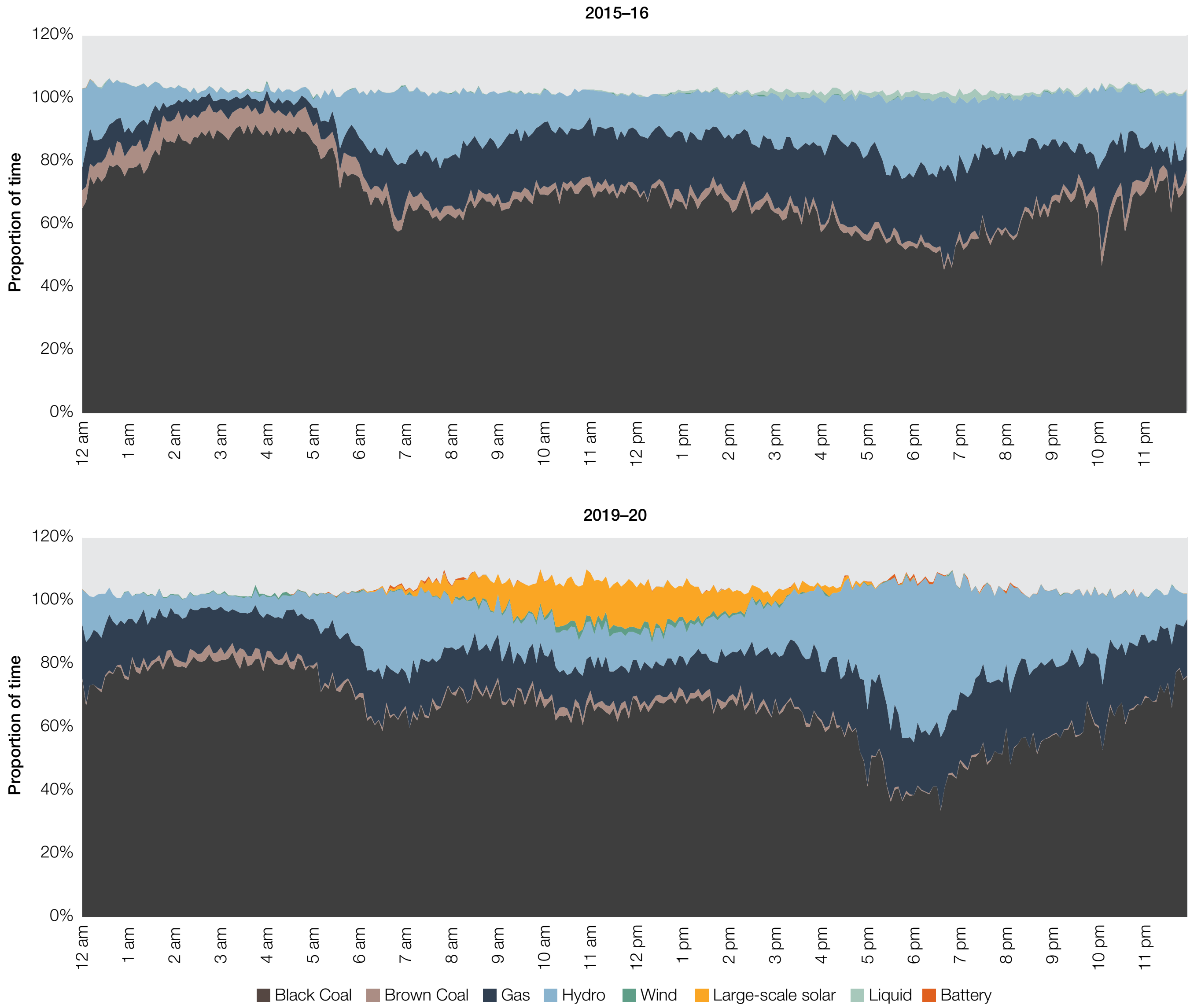
Since the removal of the direction, Queensland black coal generators have returned some capacity to higher prices, but continued to use a broader range of price bands. More recently however, these participants are structuring their offers differently by time of day, so that more is offered at lower prices in the morning and evening shoulder periods as large-scale solar comes on or off, as well as for the evening peak.

This highlights how participants' offers into the market can be sensitive to price outcomes. Relative prices are now even higher in the peak periods and even lower in the middle of the day (section 2.5). As a result some participants are offering more capacity at lower price bands in the evening peak to ensure they are being dispatched when the spot price is higher.

4.3.4 Solar generation is setting the price more often in the middle of the day, and hydro generators are setting the price more often in the evening peak

Large-scale solar generators are setting the price more often than ever before. With more capacity offered, there is also greater diversity in the fuel types setting price in the middle of the day (figure 4.12). This partly reflects rooftop solar and other factors driving lower demand at these times. And in a region like Queensland with a pronounced morning and evening peak, the technology setting price broadly reflects the shape of demand, the supply mix, and efficiencies inherent to each technology. Those efficiencies motivate how generators offer.

Figure 4.12 Proportion of time each fuel type is marginal and setting the price by time of day, Queensland



Source: AER analysis using NEM data.

Note: Figure shows more than 100% because the price can be set by more than one generator or fuel type at a time. Figure presents outcomes in NEM time (i.e. Australian Eastern Standard Time).

Compared to 5 years ago, black coal and gas generators now set the price less in the middle of the day. As large-scale solar generation offers in at mostly negative prices to ensure dispatch, this increased competition is coming from the bottom-up and replacing thermal generation, which might otherwise have set price. As participants can set price across NEM regions, this dynamic is emerging even in regions with low renewable penetration.

Hydro generation is setting price more often in the morning and evening peaks, in all mainland regions, but the shift is most pronounced in Queensland. Despite lower fuel costs than for gas or coal-fired generation, hydro generators do need to manage their water supply. This means the value of water as a fuel reflects opportunity cost. With greater evening peaks in demand and price, hydro generation has been called on more, and is setting price more often. Interestingly though, despite offering more capacity in the evening peak, black coal is setting the price less often, as the majority of this is offered at low prices.

These developments highlight the increasing importance of flexible generation, which is able to respond to fluctuations in the market, such as when large-scale solar generation comes off in the evening. Currently, the market for those generators is concentrated (section 3.1.2). With those participants now setting price more often, we will continue to monitor their behaviour to identify emerging impediments to effective competition or efficiency.

5. What are the recent trends in generator operating earnings?

Key points

- We modelled the costs, revenues and operating earnings for generators in the mainland National Electricity Market (NEM) from 2014–15 to 2019–20, based on publicly available information.
- Our analysis showed modelled operating earnings have been positive over the last 6 years. However they can vary significantly from year to year depending on prevailing spot prices, generation technology and level of contracting.
- To assess operating earnings with more accuracy, information on generator revenues and costs that is not publicly available is required.

The level of operating earnings is a useful input in our assessment of whether competition is effective, and allows us to examine the relative position of the existing generators with respect to their competitors.[67] Concern has been raised that earnings for some generators have been excessive in recent years. However, concern has also been expressed that even with higher spot prices, certain classes of generators may be uneconomic and may need to be supported to ensure they exit the market in a way that does not compromise security and reliability.[68]

We have modelled the operating earnings of generators for each generation technology using publicly available information in the first instance, as required under the National Electricity Law (NEL—box 5.1).[69] There are a number of assumptions under this approach, and as a result our assessment of operating earnings may not reflect an individual generator's actual situation. Nonetheless, this analysis is a helpful tool in analysing generator positions and provides a useful benchmark for further work to assess these earnings with more accuracy.

In this chapter we refer to revenue and operating earnings as 2 separate concepts. For the purposes of this analysis, revenue is total income earned from generation before costs, while operating earnings is revenue less operating costs. In addition, we have modelled 2 variants of revenue. Spot revenue is income earned only from the spot market. Contract adjusted revenue accounts for generators engaging in risk management through contracting, and adjusts spot revenue with simple contracting assumptions.

67 National Electricity Law Section 18B(a).

68 The Ageing Thermal Generation market design initiative of NEM 2025 is seeking to reconcile these issues. ESB, *Post 2025 Market Design Directions Paper,* April 2020, p. 3.

69 National Electricity Law Section 18D.

Box 5.1 What have we done?

We have modelled operating earnings as a high level indicator of operating profits. The National Electricity Law requires us to use publicly available information in the first instance. Therefore, we have modelled operating earnings based on:

- Revenues derived from spot market prices (dispatch multiplied by the spot price)
- Revenue based on ASX Energy contract market data and simple assumptions on the type and proportions of contracting.
- Cost estimates provided in the Australian Energy Market Operator's (AEMO) *Integrated System Plan* (ISP) as well as gas and coal spot market prices for fuel input costs.

We calculated operating earnings from spot or contract-adjusted revenue minus modelled costs. However care must be taken when interpreting modelled operating earnings as an indicator of profits, as our model does not fully reflect the revenues and costs that a participant may face. Excluded elements such as revenue from other sources, corporate expenses, costs associated with trading and marketing, well as interest and depreciation of assets, may significantly impact individual outcomes.

The revenues of individual generators will be affected, amongst other factors, by their actual contracts and other income sources, such as power purchase agreements (PPAs) and FCAS. They may also face different fuel costs, depending on the supply contracts they have in place. The composition of a participant's portfolio will also impact the risk and contracting strategies it pursues.

The ISP cost estimates exclude incremental capital expenditure costs, financing costs related to servicing loans or providing earnings to equity partners and shareholders, and tax or depreciation expenses.

Further details on the sources and assumptions we have used are contained in our methodology.[70]

This chapter sets out our analysis of the earnings of incumbent mainland NEM generators:

- Section 5.1 sets out that overall operating earnings have been positive over the past 6 years.
- Section 5.2 discusses how operating earnings vary depending on generation fuel type.
- Section 5.3 highlights that information not currently publicly available is needed to more accurately assess operating earnings.

5.1 Modelled operating earnings have been positive over the past 6 years

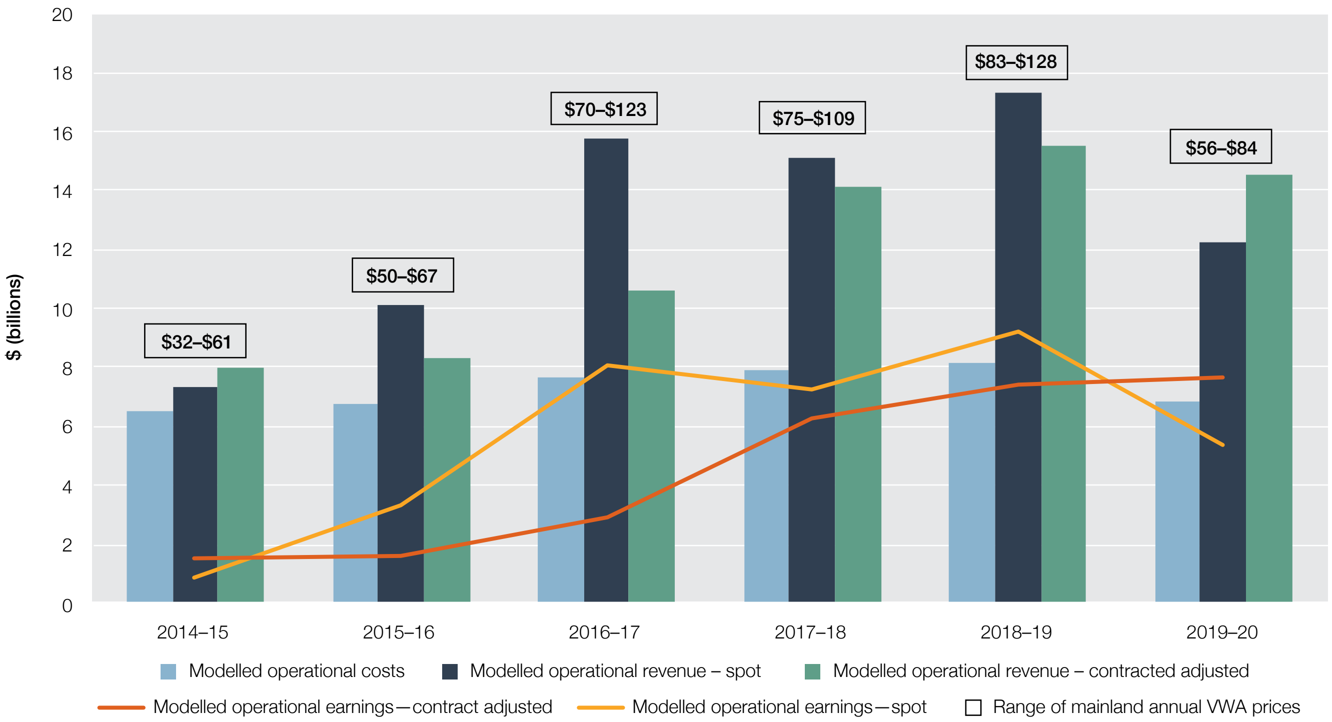
We modelled total costs, revenues and the implied operating earnings for all mainland generators.[71] Overall, modelled operating earnings have been positive over the past 6 years (figure 5.1).

Revenues modelled on spot prices fluctuate significantly from year to year, in line with spot price variations. Costs vary to a lesser extent, with fluctuations largely driven by changes in fuel costs. Earnings were highest in years where average spot prices are high, particularly 2018–19, and lower in years where spot prices are lower, such as 2014–15 (section 2.1). In 2019–20, lower earnings modelled on spot revenue were also driven by lower wholesale prices, particularly in the first 6 months of 2020. These lower wholesale prices have continued into the beginning of 2020-21.

70 AER, *Wholesale electricity market performance report 2020—Generator operating earnings approach and limitations*, December 2020.

71 Operating earnings are calculated as revenue minus costs excluding financing and depreciation costs.

Figure 5.1 Modelled spot and contract adjusted revenue, operating costs, and operating earnings in the mainland NEM



Source: AER, *Wholesale electricity market performance report 2020—Generator operating earnings modelling approach and limitations*, December 2020.

Note: The range of regional annual volume weighted average spot prices represents the highest and lowest average volume weighted average spot prices in that year across all regions except Tasmania. Volume weighted average prices are weighted against native demand in each region, and are present in $ per megawatt hour. The AER defines native demand as the sum of initial supply and total intermittent generation in a region.

For most years our modelled spot revenues are significantly different to our modelled contract adjusted revenues. This is particularly the case where there was a steep increase in spot prices from one year to the next, as occurred from 2015–16 to 2016–17. One driver of this outcome is that there can be a time lag from when spot prices rise to when this is fully reflected in contracts. This lag is also evident in 2014–15 and 2019–20 when spot prices fell from one year to the next, and contract prices had not yet fully reflected this.

5.2 Modelled operating revenue and earnings vary depending on generation fuel type

There are significant differences in modelled operating earnings between generation fuel types. This is because the revenues of different fuel types vary depending on how often they generate, the prices at the times that they operate, and their contracting strategies. They can also face different cost structures (box 5.2). While total market output is not subject to the same year to year variability as spot prices, output from different fuel types has varied in recent years. For example, increased wind and large-scale solar output has displaced some black and brown coal output (section 2.2.1). This has contributed to a decrease in revenue per megawatt hour (MWh) for coal, especially in 2019–20.

Box 5.2 Components of costs

There are a range of costs that generators face in producing electricity. The costs factored into our model can be broken down into 3 categories:

- Fixed operating and maintenance costs (FOM): Costs of keeping a generation plant running no matter how much electricity is generated. These include costs of operating and maintaining the plant, staff, insurance, minor contract work, and miscellaneous fixed charges such as service contracts, overheads, and licences.[72]
- Variable operating and maintenance costs (VOM): Costs that vary with the amount of generation output. These include spare parts, scheduled maintenance, and consumables (chemicals and oils).
- Fuel costs: Costs of the input fuels used to generate electricity. These include black coal, brown coal, and natural gas.

Different generation technologies face different combinations of these cost components.

Further details on the sources and assumptions we have used are contained in our methodology.[73]

5.2.1 Modelled revenues and costs for flexible generators are generally higher per MWh than other technologies

Modelled spot revenues per MWh also fluctuated significantly from year to year for all technologies. Over the period we analysed, revenues per MWh were lowest in 2014–15 and highest in 2018–19 for most technologies (figure 5.2).

Flexible generation

Modelled spot revenues of flexible generators like open cycle gas turbines (OCGT) and hydro are higher per MWh generated than other fuel types.[74] These generators can start quickly to take advantage of high prices, but generally operate infrequently. This is because OCGT typically face high fuel costs, and hydro generators must manage limited water supplies. In order to recover their costs they generate mostly at times when spot prices are higher, and so receive higher spot revenues per MWh of generation.

Each generation type uses different contracting strategies to help reduce the impact of spot market volatility on revenues. Flexible generators are better suited to offer cap contracts which insure retailers against high spot prices. In selling these contracts, flexible generators secure a revenue stream for themselves even when they are not generating, which is the majority of the time. As a result, the modelled contract adjusted revenues per MWh can be higher than spot revenues. This has been reflected in our modelling.

Baseload generation

Modelled spot revenues for baseload generators such as black and brown coal are lower per MWh than flexible generators. These generators are designed for continuous operation, due to high start-up and shutdown costs, low operating costs, and minimum generating requirements. Coal generators also face lower fuel costs than gas fired generation. As a result coal generators tend to offer the majority of their capacity at lower prices. This potentially exposes coal generators to a range of high and low prices, and so they offer base contracts to give longer term revenue certainty. As a result their modelled contract adjusted revenues are typically lower than modelled spot revenues.

Combined cycle gas turbine (CCGT) generators are often classed as intermediate generation as they tend to be positioned in the market between coal and flexible generators.

Renewable generation

Modelled spot revenues of intermittent renewable generators like wind and large-scale solar vary depending on the availability of their fuel sources. These generators face no fuel costs but have less certainty about when they can generate and earn spot revenue. As a result they offer their capacity at low prices to guarantee dispatch when their fuel sources are available. Because of the intermittent nature of their fuel sources, they contract using power

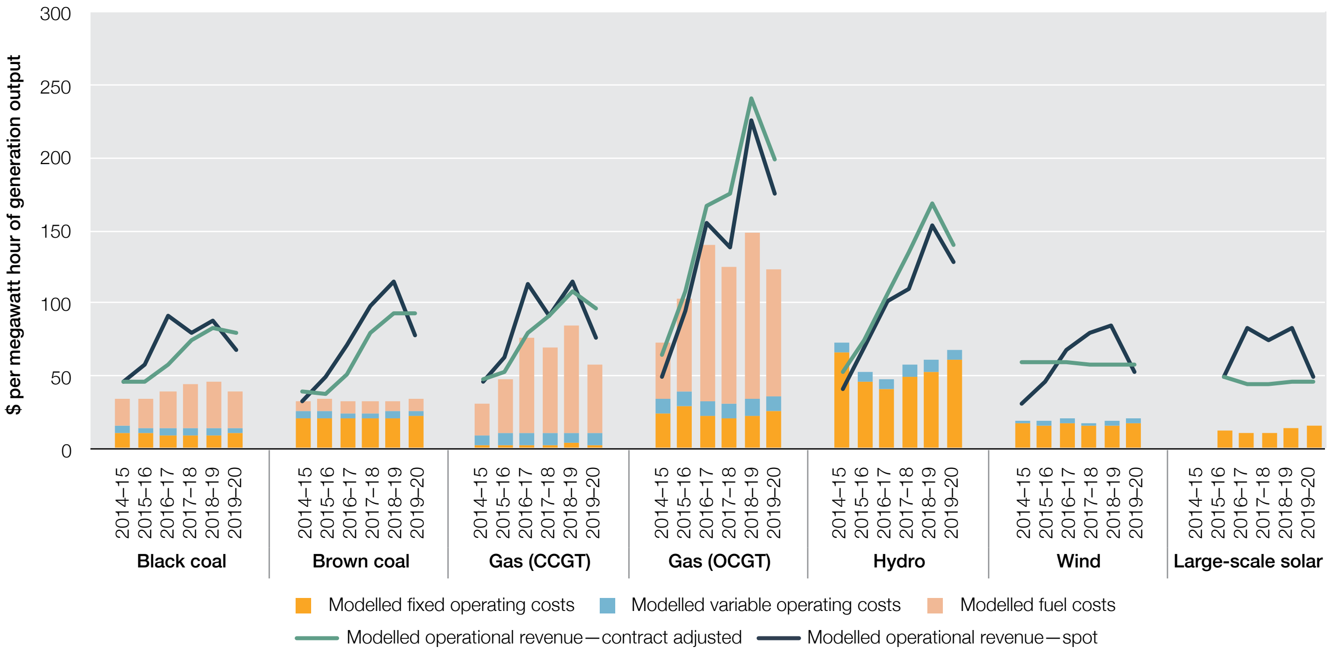
72 While public information on FOM provides a guide over time, in practice actual costs are more likely to be lumpy and plant specific. For example, for an aged generating asset, significant FOM may complicate the decision to undertake further investment to extend its life.

73 AER, *Wholesale electricity market performance report 2020—Generator operating earnings approach and limitations*, December 2020.

74 We have separated the types of gas generator technologies in this analysis into open cycle and combined cycle as they have different cost, generation, and thus earning profiles.

purchase agreements (PPA) and offtake agreements to provide revenue certainty. As we assume a fixed contract price and that all of their generation is covered by contracts, modelled contract adjusted revenue for these generators is less volatile than spot revenue. Wind and large-scale solar generation also have other revenue sources like government subsidies that are not captured in this analysis.

Figure 5.2 Modelled operating costs, and spot and contract adjusted revenue for mainland NEM, by fuel type



Source: AER, *Wholesale electricity market performance report 2020—Generator operating earnings modelling approach and limitations*, December 2020.

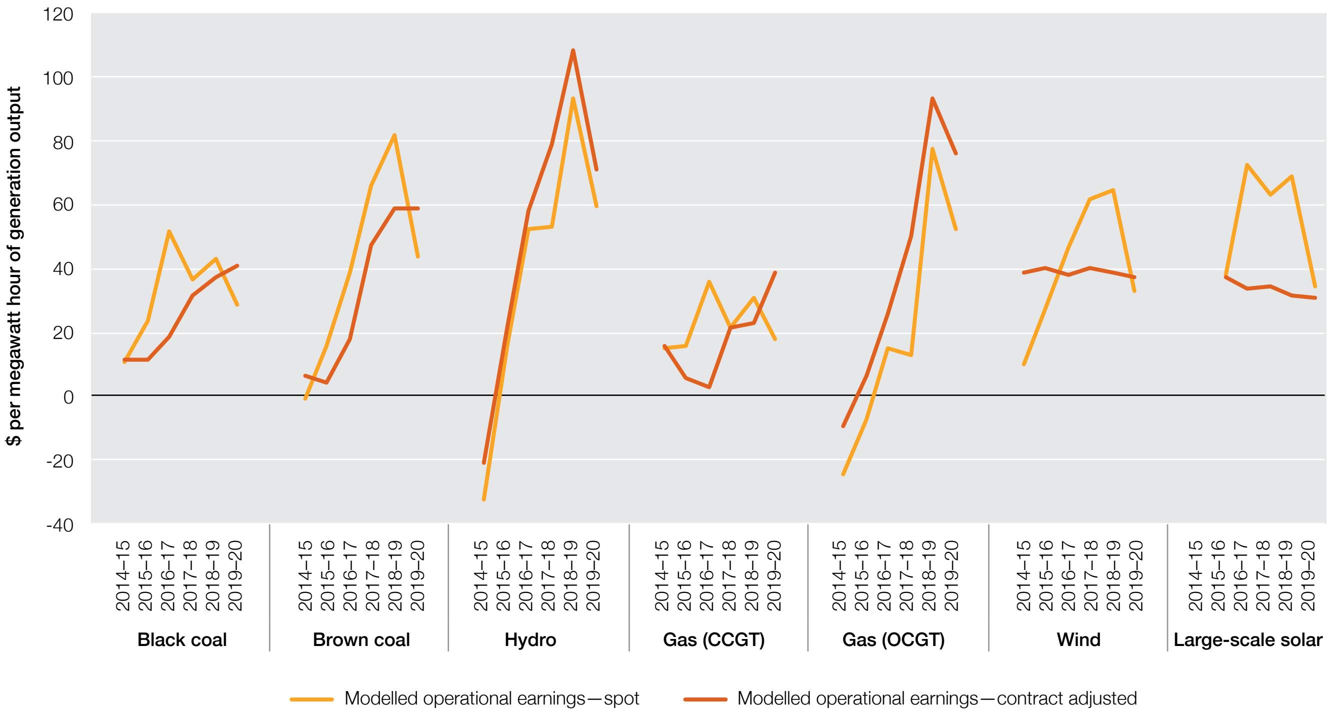
Note: The fuel types presented are a subset of market generators, and excludes dual fuel technologies, as well as generators in years where they did not operate for the full year, such as when commissioning or mothballed. Total modelled revenues and costs for each fuel type was divided by total metered generation output in order to determine $ per megawatt hour.

5.2.2 Modelled operating earnings can vary between fuels depending on their revenues, costs and level of contracting

Modelled operating earnings mirrored revenues (figure 5.3). In 2014–15, modelled operating earnings for most fuel types were low due to a reduction in spot prices, despite fuel costs also being at relatively low levels.[75] Similarly the fall in modelled operating earnings for all fuel types in 2019–20 reflected a disproportionate fall in spot prices in all regions compared to the change in fuel costs. In the intervening years outcomes varied across fuel types.

75 While not covered in this report, discussion on coal input costs are examined in our 2017 report *NSW electricity market advice - December 2017*, p. 18.

Figure 5.3 Modelled operating earnings for mainland NEM, by fuel type



Source: AER, *Wholesale electricity market performance report 2020—Generator operating earnings modelling approach and limitations*, December 2020.

Note: The fuel types presented are a subset of market generators, and excludes dual fuel technologies, as well as generators in years where they did not operate for the full year, such as when commissioning or mothballed. Total modelled earnings for each fuel type was divided by total metered generation output in order to determine $ per megawatt hour.

Flexible generation

The modelled operating earnings of flexible generators were highest when spot prices were highest, such as in 2018–19 when several regions saw record average annual prices (section 2.1). Conversely, in 2014–15 when spot prices and generation was lower, fixed costs of these generators were spread over fewer MWh of generation and modelled operating earnings per MWh were negative.

Baseload generation

All brown coal generation is based in Victoria. When Victorian spot prices were highest, such as 2018–19, brown coal modelled operating earnings per MWh were some of the highest of the technologies (figure 5.3). Brown coal has some of the lowest fuel costs of thermal generation technologies. These generators generally offer in at lower prices, but receive the regional spot price which is often set by higher cost generators.

Despite operating in a similar fashion to brown coal, modelled operating earnings for black coal generation have not been as high. Brown coal generators typically have very low fuel costs, but black coal generators face higher fuel costs on average. While higher on average, costs for black coal generators can differ depending on how they source their fuel. ‘Mine mouth’ black coal generators have lower fuel costs because they receive their coal directly from an on-site mine, while those that source their coal from further afield are more exposed to higher export coal prices. As a result, mine mouth black coal generators are likely to see operating earnings similar to that of brown coal.

Renewable generation

Wind and large-scale solar face no fuel costs, and as a result their modelled spot operating earnings are similar to or higher than those of coal generators. Modelled contract adjusted operating earnings for these generators are not as variable as other fuel types as we assume they are fully contracted at a fixed price.

5.3 More information is needed to better understand operating earnings

It is difficult to draw any strong conclusions as to whether modelled operational earnings in any year, or over a number of years, are what we would expect to see in an effectively competitive market. Given the significant variation in year to year earnings this requires ongoing and detailed analysis over longer periods. The potential difference in outcomes depending on whether modelling is based on spot market or contract market outcomes, and the variation in results for different fuel types highlights the complexity of this analysis.

The level of operating earnings is a useful input in our assessment of whether competition is effective, and can also help inform key policy decisions. Properly assessing earnings will help provide a stronger evidentiary basis for testing competing claims around generator earnings.

While we have undertaken a detailed assessment of operating earnings in this report, we were required to do this based on publicly available information in the first instance. Our modelling cannot reflect the actual positions of individual businesses or generation units without utilising information that is not publicly available. Therefore, we propose undertaking more formal information requests of generators to better understand their spot and contract revenues and costs and fulfil our functions under the NEL.

While this information would give us an understanding of generator earnings at a point in time, we consider that there is a need to better understand earnings on an ongoing basis. Annual reporting of this information would allow the AER to provide an ongoing analysis of profitability over time, potentially by participant and also by technology type.

This analysis would not only support the assessment of the effectiveness of wholesale competition, but would also allow the AER to effectively inform the policy debate. In particular, as the market transitions there is a need to provide a strong evidence base to inform the various policy decisions around market design and barriers to entry, and to ensure those decisions are effective and fit for purpose.

6. What are the prospects for new investment?

Key points

- There has been significant new entry in recent years, particularly in wind and large-scale solar. There has also been investment in batteries and one thermal generator, which replaced retiring assets.
- Little capacity has exited the market since our last report, but there are more significant exits planned over the next few years.
- Price signals for new entry that does not rely on additional funding (for example, through a RET) remain present in the National Electricity Market (NEM), particularly for wind, large-scale solar, combined cycled gas turbines (CCGT), and a range of storage technologies.

Understanding entry and exit in the 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 an important feature of effectively competitive markets, because it counters participants' ability to exercise sustained market power. Therefore, understanding whether there are price signals for new entry and investment in response to these signals is a key part of our assessment of market competition and efficiency.

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

- Section 6.1 discusses recent and upcoming capacity changes within the market, predominantly driven by new wind and large-scale solar entry.
- Section 6.2 reveals price signals for new entry may be sustained for some technologies, particularly for wind, large-scale solar, CCGT and a range of storage technologies.
- Section 6.3 shows that our results are largely consistent with what we are observing in the market by way of current, committed and announced projects.

6.1 There has been significant new entry, without major exit in recent years

Since our last report, we have seen significant new entry, particularly in wind and large-scale solar. Supply and demand balance concerns we expressed in 2018 have largely eased, however there are still periods of high demand where this balance can become tight in some regions.

6.1.1 New entry is in intermittent renewable generation, storage or replacement thermal capacity

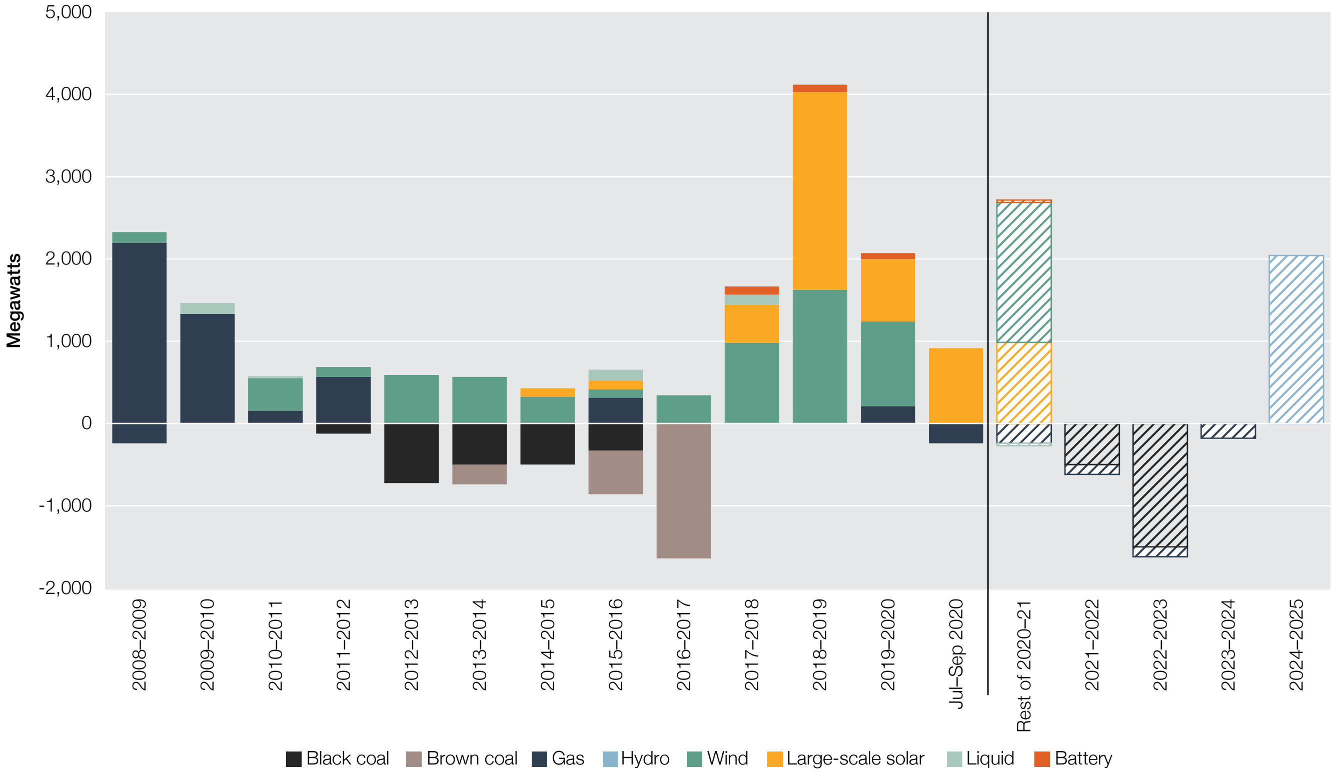
Since our 2018 report, almost all new capacity has been in intermittent renewables and batteries with one gas-fired generator entering in 2019–20 (figure 6.1). Across 2018–19 and 2019–20 around 2,654 megawatts (MW) of wind and 3,158 MW of large-scale solar capacity has entered the market. Over the same period 165 MW of batteries also entered the market.

Looking forward, there is significant further new entry expected in wind and large-scale solar, with 1,702 MW of wind and 984 MW of large-scale solar projects currently committed. All of this is scheduled to be commissioned by 2020–21, although delays in connection may change the commissioning date for a number of these generators.

A number of participants have also proposed further investment in storage technology. The single largest committed new entry is Snowy Hydro's 2,000 MW Snowy 2.0 pumped hydro project. There is also about 5,000 MW of rooftop solar capacity expected to be installed over the next 10 years.[76]

76 Jacobs, *Projections of uptake of small-scale systems* [PDF 1.5MB], report for AEMO Electricity Statement of Opportunities methodology, 9 June 2017, see figure 15, p. 29.

Figure 6.1 Past and committed future investment, and withdrawn capacity in the NEM



Source: AER analysis using NEM data.

Note: Figure uses registered capacity. Hashed areas reflect committed new entry and planned generator retirements according to the classification in *AEMO Generator Information*.

6.1.2 Significant capacity will exit the market over the next decade, but new rules will improve replacement planning

Since our last report, one generator has started to exit the market. AGL Energy closed 2 units of the Torrens Island A power station in September 2020 and the remaining units are scheduled to exit by 2022. Unlike the other generator exits we reported on in our 2018 report, AGL Energy had already invested in new capacity to replace Torrens Island, when Barker Inlet power station commenced production earlier in the year. No other generators have retired since our last report, but over the next decade a number of thermal power stations in the NEM are expected to reach the end of their economic life and cease generation (table 6.1). The largest of these will be the 2,000 MW Liddell power station in NSW.

Under new rules, from 1 September 2019 generators are required to provide 42 months' minimum notice of their formal intention to close.[77] This requirement serves to limit the chance of unexpected exit, which was a factor that may have exacerbated the impact of Hazelwood power station's closure.[78] In addition, generators also provide their expected closure years to the Australian Energy Market Operator (AEMO) to assist with long term planning. However, market inquiries suggested that some generators may accelerate the expected retirement of some assets if market conditions challenge their ability to make an economic return.

77 National Electricity Rules Clause 2.10.1.

78 AER, *Hazelwood advice*, 29 March 2018.

Table 6.1 Expected generator closure to 2030 (registered capacity over 30 MW)

EXPECTED CLOSURE YEAR	REGION	RETIRING GENERATOR (FUEL TYPE, REGISTERED CAPACITY)
2021	QLD	Mackay Gas Turbine (liquid, 30 MW)
	SA	Torrens Island A unit 1 (gas, 120 MW)
2022	NSW	Liddell unit 4 (black coal, 500 MW)
	SA	Torrens Island A unit 3 (gas, 120 MW)
2023	NSW	Liddell units 1, 2 and 3 (black coal, each 500 MW)
	SA	Osborne (gas, 180 MW)
2024	-	*No expected closures*
2025	-	*No expected closures*
2026	-	*No expected closures*
2027	-	*No expected closures*
2028	QLD	Callide B units 1 and 2 (black coal, each 350 MW)
2029	NSW	Vales Point Power Station units B5 and B6 (black coal, each 660 MW)
	VIC	Yallourn unit 1 (brown coal, 360 MW)
2030	VIC	Yallourn unit 2 (brown coal, 360 MW)
	SA	Mintaro Gas Turbine (gas, 90 MW), Snuggery unit 1 (liquid, 63 MW), Dry Creek units 1, 2 and 3 (gas, each 52 MW), Port Lincoln Gas Turbine unit 1 (liquid, 50 MW), Dalrymple North Battery energy storage system (battery, 30 MW)

Source: AEMO Generator information Generating unit expected closure year—November 2020.

Note: Only scheduled and semi-scheduled generation are included.

6.2 There are price signals for new entry for a number of technologies

While there has recently been considerable investment in wind and large-scale solar and more is committed, much of this has been supported by various government schemes. For example, the Victorian Renewable Energy Target (VRET) supported the entry of 6 new wind and large-scale solar generators totalling over 900 MW of capacity through a reverse auction.[79] As a result, it is important to assess whether, in the absence of these subsidies, the market signals for new entry are present and, if so, for which technologies.

6.2.1 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 would 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, 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. 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 in response, then we might be concerned the market was not performing as intended.

We undertook modelling to compare potential spot revenue to estimated costs of new entry to assess whether current spot prices reflect the underlying costs of new entry for generation and storage technologies.[80]

79 Department of Environment, Land, Water, and Planning, *Victorian renewable energy auction scheme*, successful projects of the Victorian Renewable Auction 2018, Victoria State Government, 13 July 2020.

80 As required by the National Electricity Law, Section 18B(b).

However, investment decisions are unlikely to be made based on spot outcomes alone. In deciding when to invest, new entrants will likely account for other factors, with future expected revenue 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. 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 frequency control ancillary services (FCAS) or other system services.

In undertaking our analysis, the National Electricity Law requires us to use public information in the first instance. Unfortunately, there is limited public information on contract prices, particularly for over the counter arrangements. Prices for Australian Securities Exchange (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 used spot prices in our analysis as they are publicly available.

To calculate historical potential spot revenues, we assessed spot prices in 2018–19 and 2019–20 in all regions. This builds on the work in our 2018 report, where we assessed outcomes for 2014–15 and 2017–18. From the chosen years, we estimated the potential spot revenue a new entrant generator could receive depending on how often it produces. For storage technologies, we estimated the potential spot revenue a new entrant storage asset could receive depending on how many days in a year it trades with a daily buy low, sell high strategy (box 6.1).

Box 6.1 How do we allocate costs and potential revenue?

In estimating whether the potential revenue is sufficient for a new entrant to recover their costs, our calculations are not based on an assumed level of production. Instead we have modelled a range of possible results depending on how often a new entrant may operate.

For generation technologies, we use capacity factors to determine this. A capacity factor is the amount of energy produced by a generator in a year, expressed as a proportion of its possible maximum production in that year. This results in a range of possible estimates from 0% to 100%. However, no generator can operate 100% of the time. Accordingly, we limited the range of capacity factors used in our calculations to reflect achievable levels of production, partly based on the current capability observed for each technology type.

Storage technologies need to first pay to store energy before they can discharge into the market, so it was not appropriate to use capacity factors. Instead, we assumed a new entrant would adopt a daily buy low, sell high strategy. We use the number of trading days in the year to create a range of possible estimates from 0 to 365 days of production. However, given the significant costs involved we assume that participants would target a minimum level of production. So we use a minimum of 12 trading days for all storage technologies.

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 generation and storage technologies. New entrants would also need to account for more site-specific modelling of costs, risk and production, which are not captured in our analysis. As this assessment focuses on new entry, we did not include models of incumbent generators' costs or potential revenues as part of this analysis.

We levelise our cost estimates, which for generators means that a new entrant's costs are allocated across each megawatt hour of energy it produces over its expected life. For storage technologies, a new entrant's costs are allocated across the number of days in a year it trades, assuming a daily buy low, sell high strategy. Levelising costs, creates a minimum price at which a new entrant will need to receive in order to recover its costs.

There are a number of significant limitations of this analysis. We did not model all technologies, and we made some simplifying assumptions. Our analysis is also retrospective, to see if the investment the market delivered aligned with what we might have expected to see, based on spot price outcomes alone.

Despite these limitations, we consider the analysis 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 information on our approach, limitations, and our detailed findings are set out in our methodology.[81]

81 AER, *Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach, limitations and results*, December 2020.

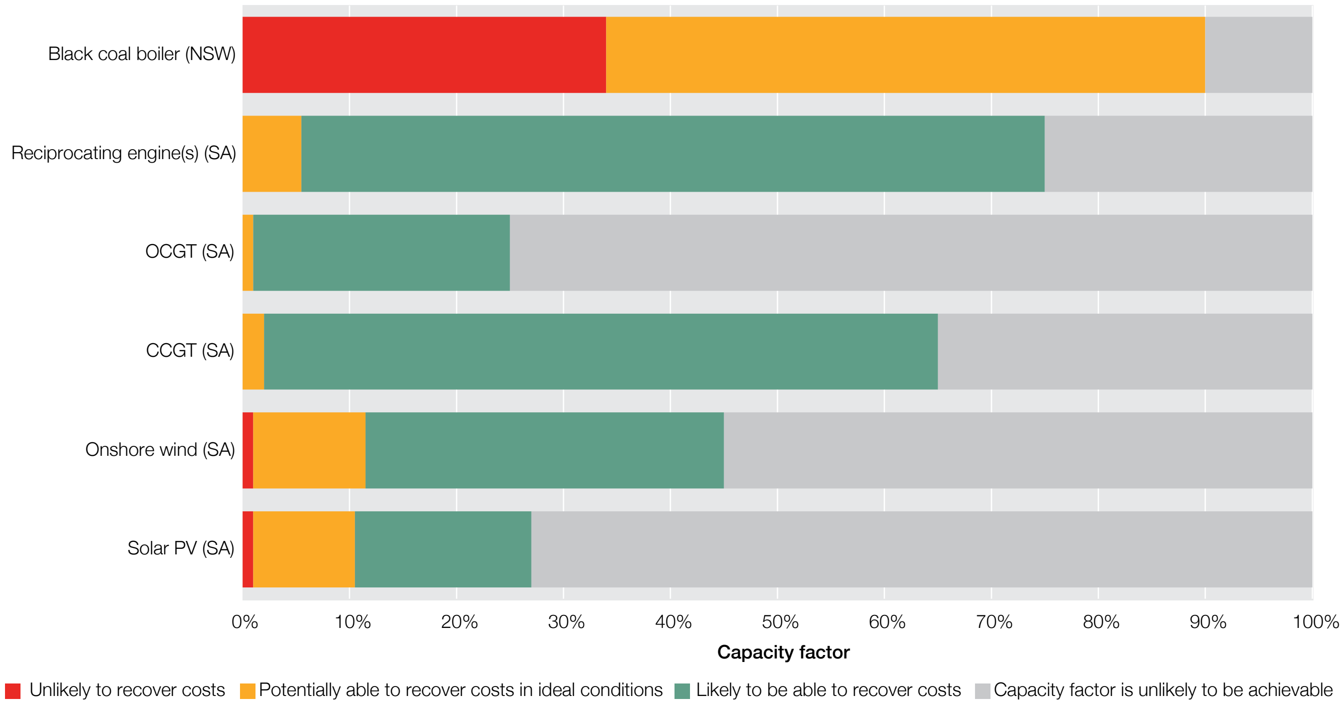
6.2.2 Price signals for the new entry of solar, wind and CCGT technologies persist despite recent lower prices

Our findings suggest that a price signal for new entry exists for some technologies, despite lower spot prices in 2019–20. In our 2018 report, we found that a signal for the new entry of large-scale solar, wind and CCGT was emerging. Our analysis for 2018–19 and 2019–20 shows that this signal has remained sustained for these technologies (figure 6.2 and figure 6.3). This finding is supported by continued rapid cost reductions for large-scale solar and wind technologies. For example, the cost of building large-scale solar projects has fallen from $135 per megawatt hour (MWh) in 2015 to between $45 and $61 per MWh in 2020, as a result of falling manufacturing costs internationally and lower financing costs in Australia.[82] At the same time, significant reductions in gas prices has reduced costs and assisted in sustaining a price signal for CCGT generators (section 2.4.1).

In addition, our findings suggest an emerging signal for new entrant open-cycle gas turbines (OCGT) and reciprocating internal combustion engines (RICE).[83] In 2017–18, there was a general uplift in prices, but a reduction in price volatility. In 2018–19 and 2019–20, there have been more prices greater than $300 per MWh than in 2017–18 (section 2.3). While still lower than 5 years ago, this increase in price volatility may be enough to support investment in the right conditions, as OCGT and RICE generators typically only operate at times of high prices. This has important implications for the market transition. There will be a greater need for these forms of fast start, flexible generation that can provide firming services as the NEM shifts to a generation mix that relies increasingly on intermittent renewable generation. We have already started observing greater variation in prices in the evening peak compared to the rest of the day, which may further support these flexible generation types into the future (section 2.5.3).

A new entrant black coal generator, while potentially able to recover its costs in ideal circumstances, does not have as strong a signal as the other technologies. This reflects the high costs associated with establishing such a generator, and that a new entrant would likely rely on long term contract arrangements to support investment decisions.

Figure 6.2 Likelihood for new entrant cost recovery for 2018–19, by generation technology type

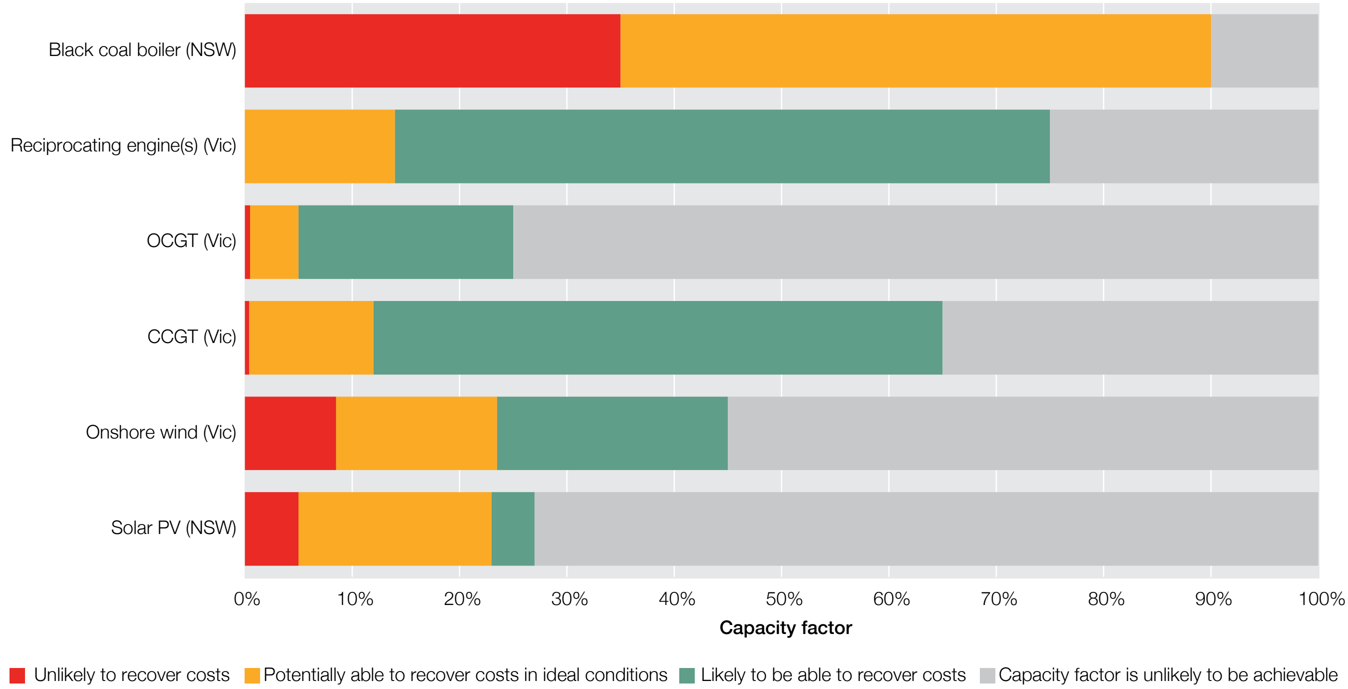


Source: AER, *Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach, limitations and results*, December 2020.

82 ARENA, Large-scale solar, ARENA website.

83 We have separated the types of gas generator technologies in this analysis into open cycle, combined cycle and reciprocating internal combustion as they face different investment signals.

Figure 6.3 Likelihood for new entrant cost recovery for 2019–20, by generation technology type



Source: AER, *Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach, limitations and results*, December 2020.

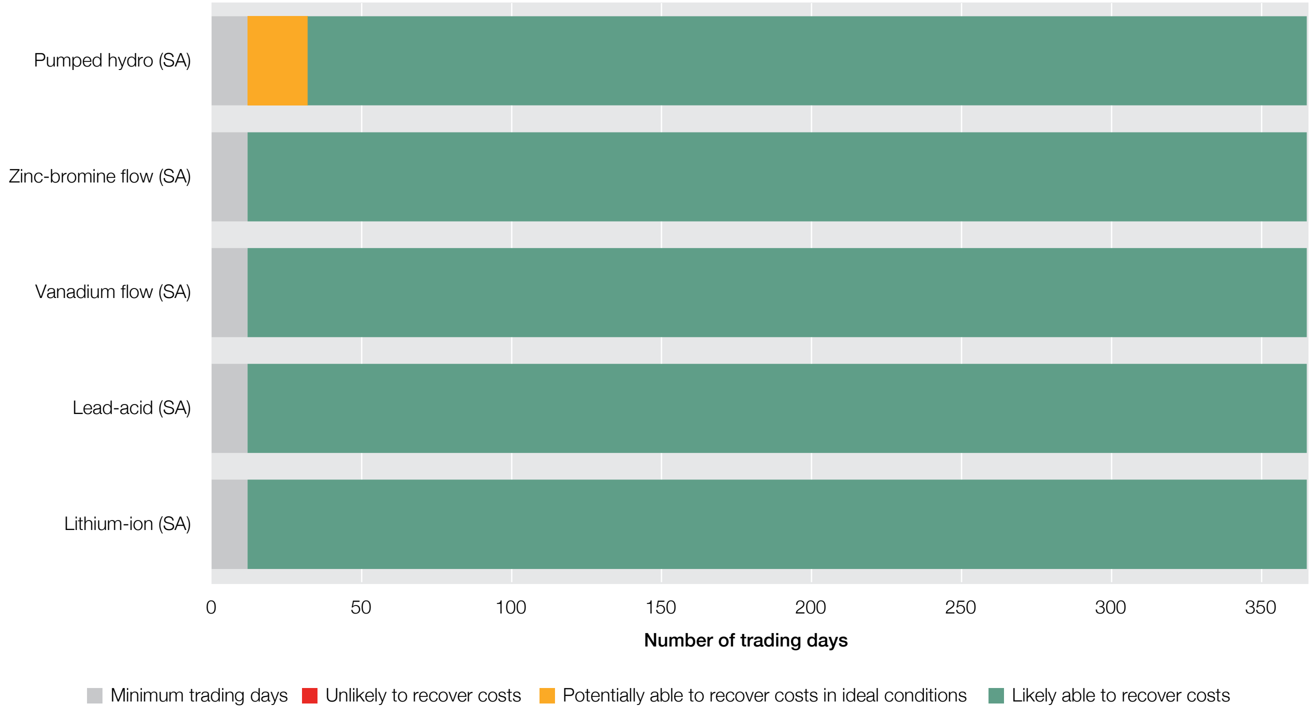
6.2.3 Price signals for new entry exist for a range of storage technologies

For storage technologies, our findings suggested that a range of new entrants would have been likely to recover their costs in 2018–19 and 2019–20 (figure 6.4 and figure 6.5). This indicates that there is sufficient variation between maximum and minimum prices each day.

Batteries are emerging in the market, and we expect further investment. To date all batteries in the NEM are lithium-ion, suggesting that this may currently be the most accessible storage technology for investment. However, some participants have also noted that due to the popularity of lithium-ion, other battery technologies may get overlooked. This is despite other technologies having different benefits and efficiencies, which may prove better suited to some applications.

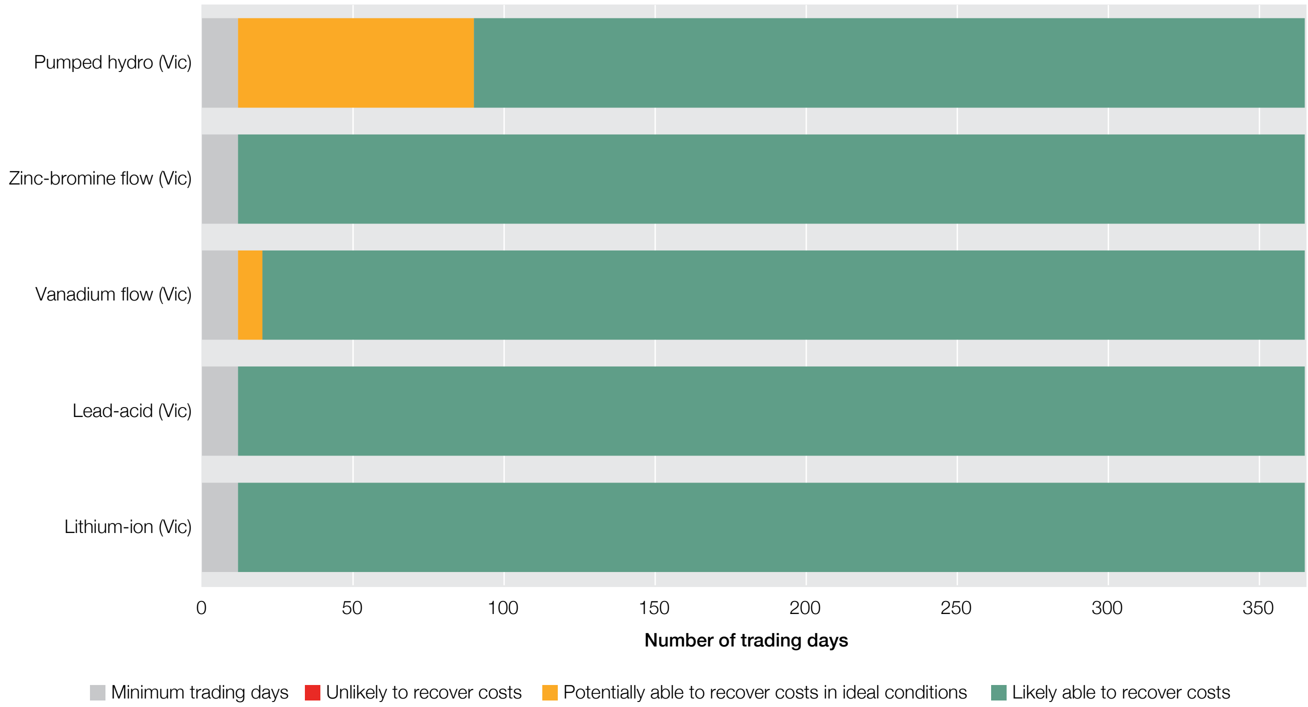
Our findings also suggest new entrant pumped hydro energy storage would also be likely to recover their costs. However, not captured in the modelling is the fact that this technology requires a site with adequate storage capacity and elevation differential to be viable, which we have not modelled. As a result, the most likely investment in pumped hydro would come from an incumbent participant that already controls the necessary sites and infrastructure.

Figure 6.4 Likelihood for new entrant cost recovery for 2018–19 for storage technology type



Source: AER, *Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach, limitations and results*, December 2020.

Figure 6.5 Likelihood for new entrant cost recovery for 2019–20 for storage technology type



Source: AER, ***Wholesale electricity market performance report 2020—LCOE & LCOS modelling approach, limitations and results***, December 2020.

6.3 These results are largely consistent with market observations

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

As noted earlier, there has been significant investment in wind and large-scale solar and there is more committed capacity coming in the future. Australia is particularly well suited to wind and large-scale solar due to our abundance of sunshine and strong winds, the absence of harsh winters, and a seasonal peak in summer when large-scale solar is most effective.

We have also observed investment in RICE when AGL Energy commissioned Barker Inlet power station as a replacement for the retiring Torrens Island A power station. RICE is also a flexible technology that suits the upcoming change to five minute settlement, and we may see more in the future. Similarly, we are also aware of some small OCGT upgrades to enable faster start capability in preparation for that rule change.

Despite our findings, we are not aware of any committed investment in CCGT. However, this might not be unexpected as the generators tend to be large capacity and suited to long term firming roles. As more coal-fired generators retire, there may be a need for investment in CCGT to fill the gap.

Consistent with our analysis, there is no committed new investment in coal-fired generation, and the investment environment for this technology looks to be challenging. Typically, coal-fired generators are large units with high fixed costs that need to be recovered over many years. Coal-fired generators tend to be less flexible, relying on relatively constant high production levels because frequent start-up and shut-down leads to increased fuel, maintenance, and operations costs. The broader shift in the market towards intermittent generation indicates a greater need for generators that can operate flexibly, which raises the risk that a new coal plant will be underutilised.

Supporting our findings for storage, supporting our findings, there is committed investment in pumped hydro energy storage from Snowy Hydro. However, this project benefits from existing reservoirs and infrastructure—ideal circumstances that a new entrant may not have access to.

Of the other storage technologies, we have seen investment in lithium-ion battery technologies in the NEM. But in the future we may see investment in a broader range of storage technologies as costs mature and the benefits of each technology are further understood. Grid-scale batteries are still relatively new and may end up being just one of the many technological solutions in the optimal storage and firming portfolio.

The observations on flexible capacity have perhaps the most significant ramifications for the market. In particular, with more large-scale solar generation in the middle of the day, flexible generation is needed to respond to sudden fluctuations in output, as well as in the evening peaks as the sun sets and large-scale solar generation reduces (section 2.5). While there has been plenty of new entrant large-scale solar and wind generation, we have not seen similar new entry in flexible technologies. In the coming years, more intermittent capacity is coming online and more thermal generation is scheduled to exit. If the price signal for new investment in flexible technology remains sustained, we should see new flexible generation to replace some of the retiring capacity and firm up the new intermittent generation. But if this investment does not eventuate, there may be other factors discouraging new entry. Given the rising importance of flexible firming capacity in the overall generation mix, we will monitor investment trends in these technologies going forward.

7. Are there barriers to entry and impediments to efficient price signalling?

Key points

- Our market enquiries identified a range of potential barriers to entry and impediments to efficient price signalling in the National Electricity Market (NEM). Investment in capital intensive, long lived assets requires some confidence over future prices. The risks of investing in these technologies are significant in an environment of uncertainty about future technology costs, an unclear path for the exit of large generators, and demand uncertainty (particularly around large loads).
- Other barriers to entry and impediments to efficiency raised in our market enquiries included the current market design and structure, government investment and intervention, the increasing use of directions and increasing congestion costs.
- However, it is difficult to accurately assess what impact these barriers may be having. For technologies for which we are seeing investment, such as wind, large-scale solar generation and batteries, much of the investment has been supported by renewable energy target schemes. For high-cost long-term assets where we are not seeing investment, it is not clear which of these barriers are impacting investment decisions and to what extent.

As highlighted in chapter 6, price signals for new investment appear to be present for a range of technologies. Understanding the nature of barriers to entry and impediments to efficient price signals helps us to assess whether new entry might occur in response to price signals. New entry is an important feature of effectively competitive markets, because it may constrain incumbents' ability to exercise sustained market power.

For this review, we have adopted a broad approach to defining barriers to entry, covering barriers to investment for new entrants, obstacles to expansion for incumbent participants, as well as impediments to efficient price signalling.

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

- Section 7.1 identifies potential barriers to entry and impediments to efficient price signalling in the NEM.
- Section 7.2 explains the impact of barriers to entry and impediments to efficiency on NEM investment dynamics.

7.1 Our review highlighted a range of barriers to entry

In undertaking our analysis of barriers to entry, we spoke to a range of market participants and stakeholders. From these market enquiries, the following identifies the most common issues.

7.1.1 There are structural features of the market that make entry challenging

There are inherent structural characteristics of the market that can act as a barrier to entry. Many generation technologies are high-cost, long-term investments. The fact that significant costs associated with these technologies are sunk and cannot be recovered acts as a barrier to entry for new and existing generators.

This barrier is particularly relevant in the context of a transforming market. For investments with long time horizons, generators require revenue certainty well into the future. However it is difficult to provide this certainty in an environment of technological change. Rapid advancements in technology could deliver new innovation or efficiency improvements, which could then strand the technologies that need to recover their investment costs over long periods. Market participants noted that the potential for future asset stranding leads to a degree of caution on investing.

There is also significant supply and demand uncertainty associated with a transforming market. There is doubt around the exit of large generators and an uncertain outlook for energy intensive industries which make up the majority of demand.

These features of the market make entry for some generation technologies challenging in the current environment, even if the other barriers to entry identified in this chapter were not present.

7.1.2 Market concentration, vertical integration and contract market liquidity may affect new entrants' ability to secure ongoing revenue certainty

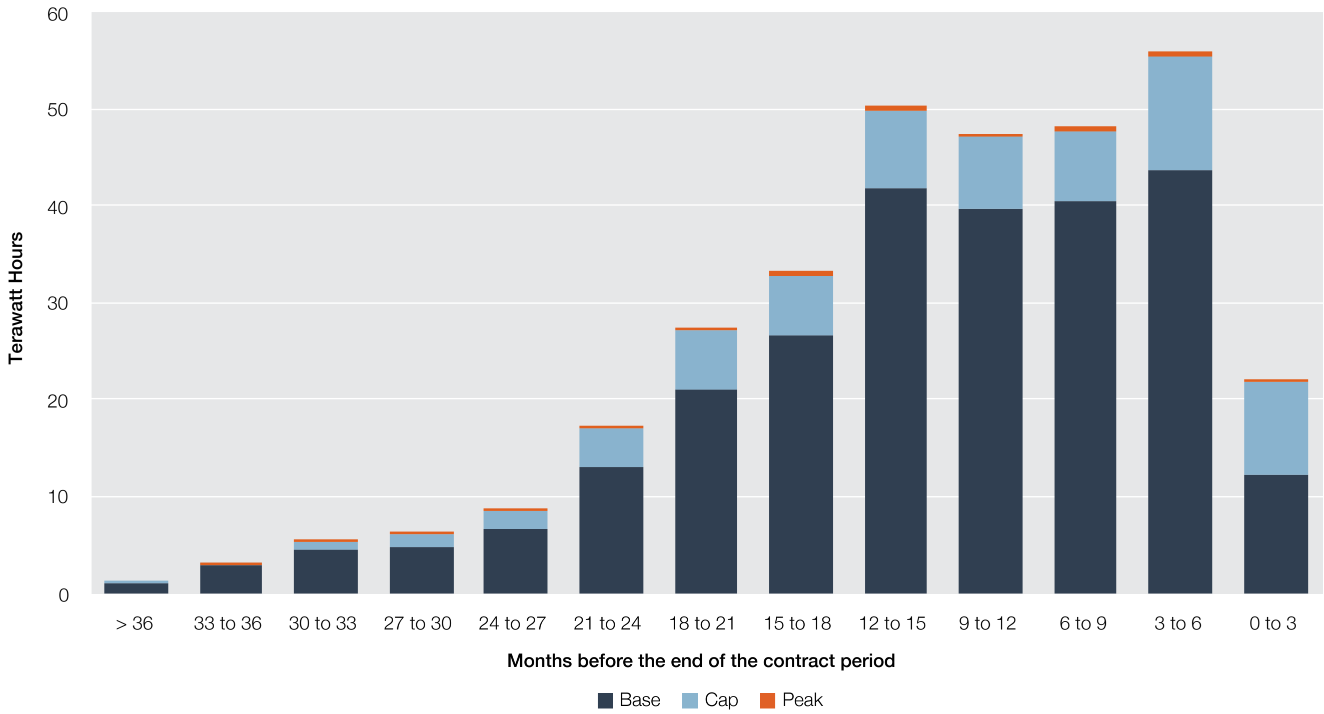
Chapter 3 discussed the concentrated nature of the generation sector across the NEM and the extent of vertical integration. Our enquiries suggest this industry structure poses challenges for new entrants.

Stakeholders indicated it is difficult to attract debt finance to support investment without long term contracts in place to provide ongoing revenue certainty. To provide revenue certainty, counterparties to contracts need to be credit-worthy and wanting to purchase contracts in large volumes. However, participants noted few counterparties meet these criteria.

Participants also highlighted difficulties in contracting, even where suitable counterparties exist. Many potential counterparties have already accounted for their consumption through vertical integration and/or contracting, and have no commercial incentive to enter into additional agreements. This has led some generators to develop a retail presence to establish revenue certainty. But operating a retail business adds an additional range of costs and risks.

Concerns were also raised about liquidity in contract markets and the impact this has on investment signals. Since our last report, contract market liquidity has generally improved across regions other than South Australia (where liquidity remains very low, section 3.6). Despite improving liquidity, the vast majority of contract trading continues to occur within 18 months of the close of the contract (figure 7.1). But for participants to invest, they generally require revenue certainty well into the future. While the market may be in a better position to help participants manage exposure to spot prices, poor liquidity more than 18 months out means that contract market trading is unlikely to provide sufficient revenue certainty to support new investment.

Figure 7.1 Futures contract trades in the lead up to the contract period, 2019–20



Source: AER analysis using ASX Energy data.

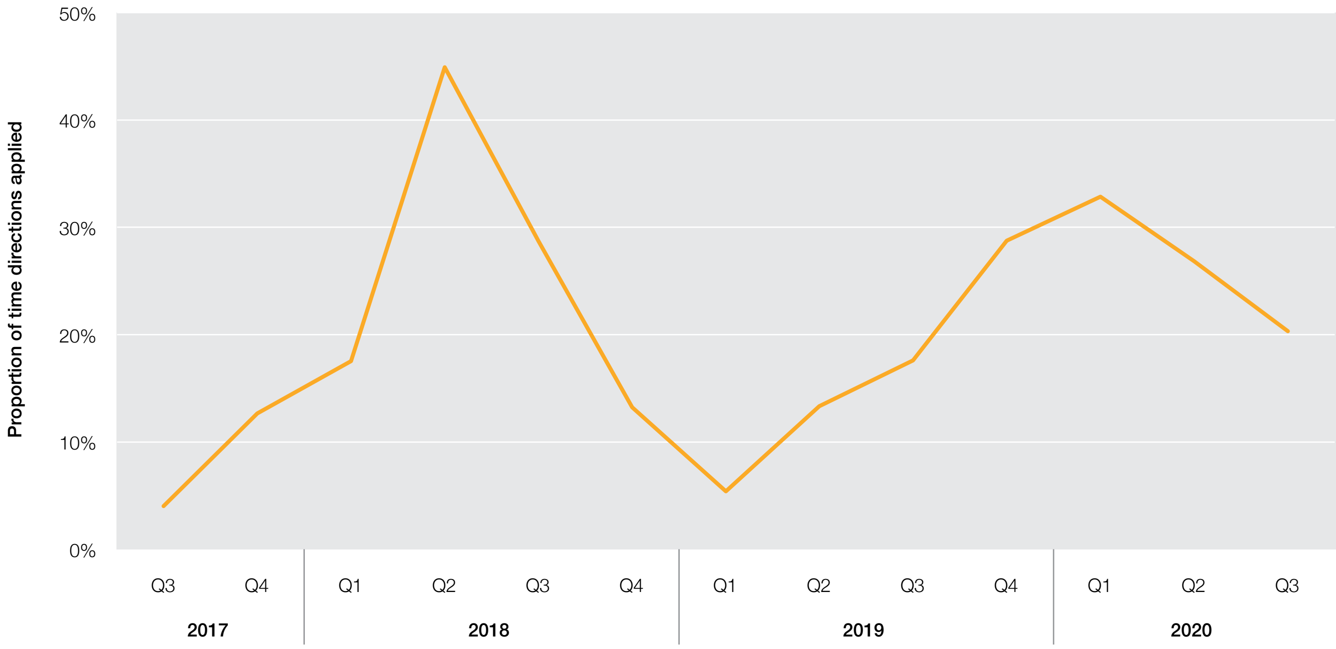
7.1.3 AEMO directions may compromise aspects of market efficiency

Some participants highlighted concerns with the increased use of directions, particularly in South Australia.

Where the Australian Energy Market Operator (AEMO) identifies a risk to system security or reliability, it can direct an offline unit that is otherwise capable of operating to start generating. It can also direct a unit already in operation to either increase or decrease its output in response to security or reliability concerns. In South Australia, directions are typically issued to specific generators to operate to provide system strength, usually during periods of forecast low prices due to high wind output.

AEMO's use of directions in South Australia has increased significantly in recent years (figure 7.2). Since 2018 directions have been used at least 5% of the time in every quarter, and as much as 45% in one quarter.

Figure 7.2 Proportion of time directions applied in South Australia



Source: AER analysis using AEMO data, *Quarterly Energy Dynamics Q4 2019, Q3 2020*.

Note: Figure presents proportion of time in each quarter that direction(s) applied.

Concerns were raised by some participants that the frequency of directions can compromise the core principles of the NEM. In particular, it was argued the frequent use of directions compromised efficient market based dispatch based on generator offers. It was suggested that decisions on how to operate assets were increasingly being made by AEMO, rather than generators.

In late 2019, the Australian Energy Market Commission (AEMC) made new rules to address issues identified in its *Investigation into intervention mechanisms and system strength in the NEM*.[84] The rule changes removed distortions that intervention pricing can cause in the wholesale market when addressing system security concerns. However, until frameworks evolve to facilitate the procurement of system services such as inertia, directions are likely to be required to maintain system security in South Australia.

In late 2020, the AEMC was consulting on multiple rule change requests relating to system services.[85] These include a proposed rule for a synchronous services market and new arrangements for procuring system services. A draft determination is expected in late Q1 2021.[86]

84 AEMC, *Investigation into intervention mechanisms in the NEM—Final report*, market review, 15 August 2019.

85 AEMC, *Consultation begins on new ways to deliver system services as the power system evolves* [media release], 2 July 2020.

86 AEMC, *New timeframes set for system services arrangements* [media release], 24 September 2020.

7.1.4 Congestion is an issue requiring reform, but the impacts need to be carefully considered

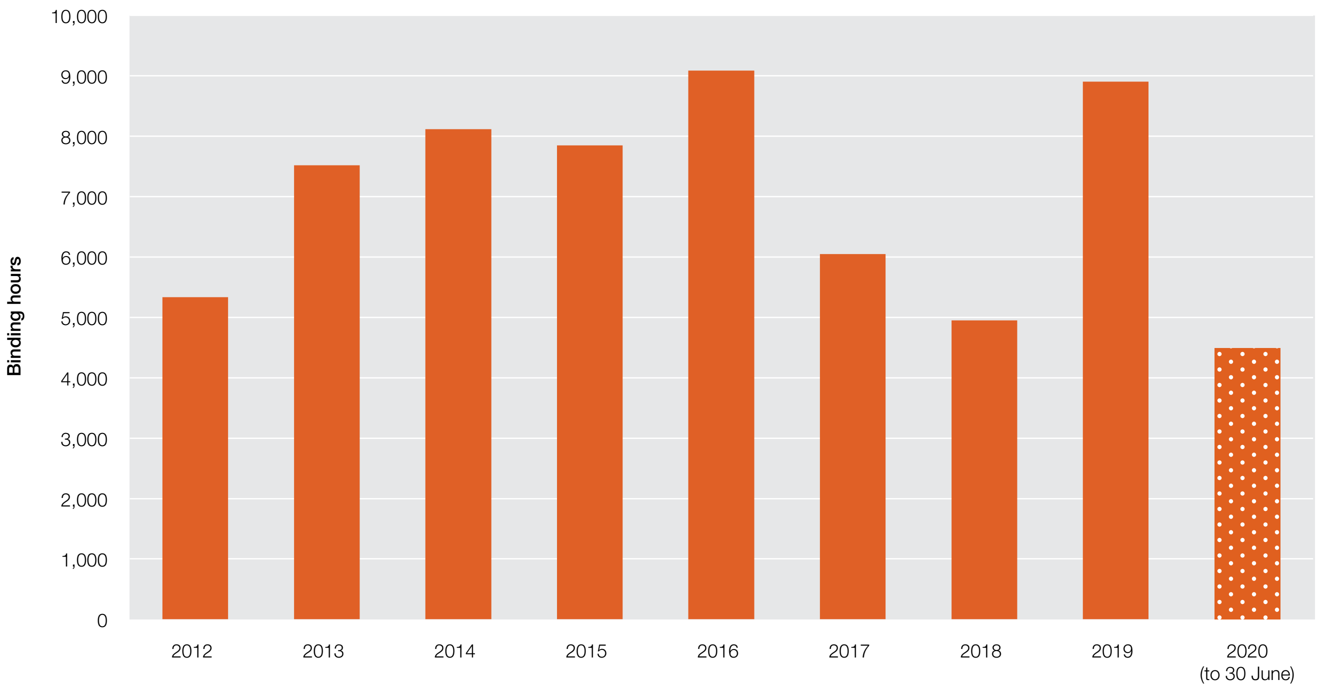
Our enquiries found that rising costs of congestion are creating inefficiencies in the market. However, we also heard that potential reforms to address congestion create uncertainty for participants.

'Congestion' occurs when technical limits of transmission cause a bottleneck on the network. Under the current market design, some participants have opportunities to benefit from congestion, by taking advantage of their location in the network to influence when and where they are dispatched, or otherwise impact spot prices. For example, a generator positioned close to an interconnector may be able to limit flows, when energy might otherwise flow more freely from one region to another. This can result in inefficient outcomes, as congestion may cause higher priced capacity to be dispatched ahead of lower priced capacity. However eliminating congestion completely would also be inefficient because building the transmission capacity to do so would be extremely costly.[87]

AEMO uses constraints to optimise matching supply to demand, while also keeping the network safe and within its technical limits. If parts of the network reach technical limits the constraints managing them become binding, and have a financial impact. System normal constraints are always in place to manage the limits of the network in its normal operating state—they are not a result of outages on the network, such as line outages caused by bushfires. The more frequently constraints bind, the more congested the system becomes. As this occurs, the more likely it becomes that higher priced capacity will be dispatched ahead of lower priced capacity.

Since 2012, there has been no clear trend in the number of hours network constraints were binding. The hours that system normal constraints bind varies significantly from year to year (figure 7.3).

Figure 7.3 Hours that system normal constraints were binding



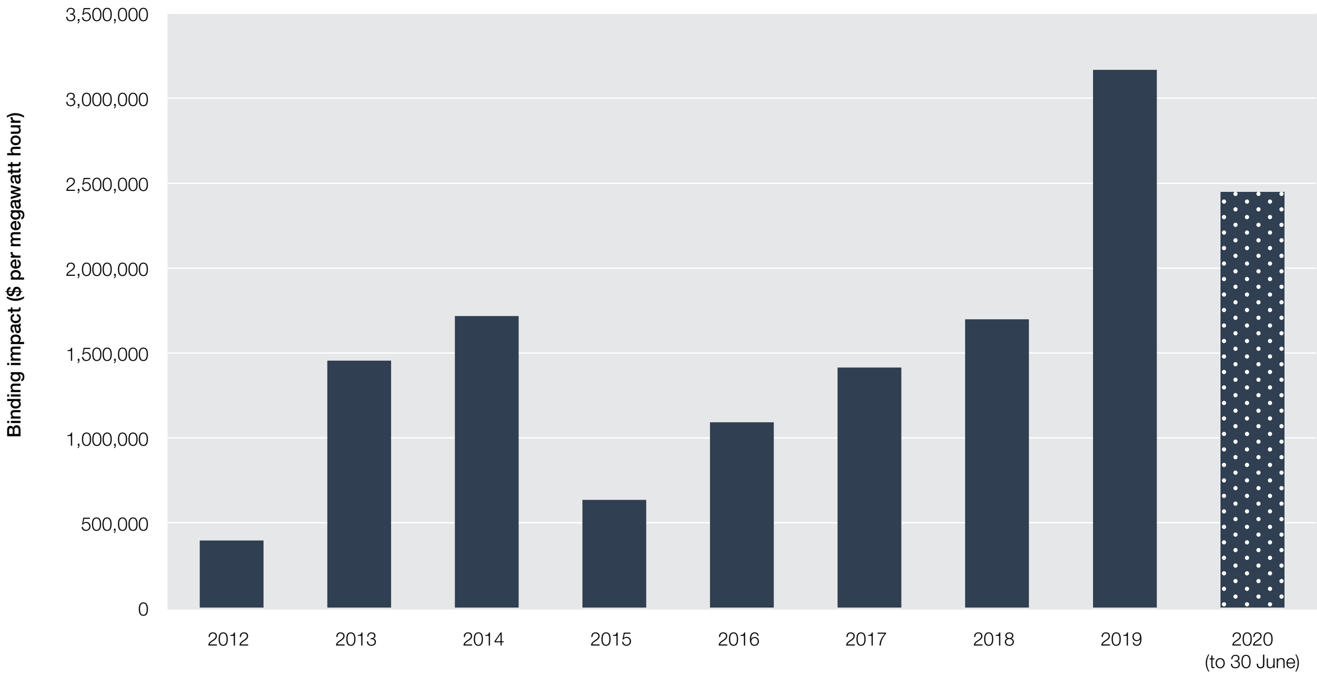
Source: AER analysis using AEMO congestion information.

Note: 2020 only includes data up to end of July 2020. Data excludes impacts from FCAS, outages, network support and commissioning constraints. Further details can be found at [AEMO congestion information](#).

However, despite this variability, the costs of congestion have steadily risen since 2015, in line with increases in average prices (figure 7.4). In 2019 and 2020, even with falls in prices, the impact of binding constraints were at their highest level in recent years. This reflects that while average prices have fallen, spot prices when constraints bind tend to be higher than in previous years.

87 AEMC, *Transmission access reform—Update paper*, market review, 26 March 2020.

Figure 7.4 Binding impact from system normal constraints



Source: AER analysis using AEMO congestion information.

Note: The binding impact of a constraint is derived by summarising the marginal value for each dispatch interval from the marginal constraint cost re-run over the period considered. The marginal value is a mathematical term for the market impact arising from relaxing the right hand side of a binding constraint by one megawatt (MW). Binding impact represents the financial pain associated with that binding constraint equation and can be a good way of picking up congestion issues, however it is only a proxy (and always an upper bound) of the value per MWh of congestion over the period calculated. 2020 only includes data up to end of July 2020. Data excludes impacts from FCAS, outages, network support and commissioning constraints. Further details can be found at *AEMO congestion information*.

Transmission access reform aims to resolve both operational and investment inefficiencies resulting from congestion, and allow participants to manage congestion risks. The core elements of the proposed reforms are the introduction of locational marginal pricing, where market participants would receive/pay a price that would vary with their location, and financial transmission rights.

Stakeholder feedback indicated that even if ultimately beneficial, the reforms may create uncertainty in the market and impact efficient investment decisions (section 7.1.4). Creating a business case for investment that accounts for potential reform scenarios is complex, and may cause participants to delay doing this until reforms are implemented and their impact on market dynamics is clear.

Stakeholders acknowledged that congestion creates costs and inefficiencies in the market, and is an issue that needs to be addressed. However the proposed transmission access reforms were identified as potentially having a significant impact on the market. In our enquiries, stakeholders expressed concerns with the scale and speed of the proposed reforms. A range of stakeholders highlighted that care needs to be given in considering potential solutions so as to not discourage future investors by creating market uncertainty.

7.1.5 Policy predictability encourages investor confidence

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

However, the policy predictability issues stakeholders raised have evolved from those raised in our 2018 report. At that time, stakeholders identified instability around emissions policy settings as a key impediment to investment in the NEM. This was after a failed attempt to integrate energy and emissions policy through initiatives including the National Energy Guarantee. While emissions policy remained a concern for some stakeholders, a wider theme from our consultations in 2020 was that the sheer volume of policy reforms being considered made the investment environment challenging.

Since our last report, a range of reforms to manage aspects of the energy transition have been progressed. In particular, the potential scope of changes arising from the Energy Security Board's (ESB) *Post 2025 market design for the National Electricity Market* (NEM 2025) was identified as a reform with major implications. It was argued that NEM 2025 could change fundamental aspects of current frameworks, including arrangements for incentivising new investment. In this environment, some participants noted they were holding off on investment decisions until more clarity on likely outcomes emerged.

In addition, participants argued that introducing new regulatory measures or laws raises uncertainty around how those measures may apply, particularly if strong penalties are involved. For example, changes to the *Competition and Consumer Act 2010* in 2019 introduced new measures to prohibit energy market misconduct.[88] Those measures include, in exceptional circumstances, a divestiture order by the Federal Court, which would require an energy business to divest some or all of its assets. In our enquiries stakeholders did not believe those powers were impacting market behaviour. However, they expressed concerns about the potential impact on the market if the powers were to be used, and the uncertainty that would create.

7.1.6 Government ownership may contribute to investor uncertainty and act as a barrier to entry

Through our market enquiries participants identified government ownership of generation and the potential for further government investment as a barrier to entry. This was also identified as a significant barrier to entry in our 2018 report. Historically, government owned utilities ran the entire electricity supply chain in Australia. Currently, the Tasmanian Government-owned Hydro Tasmania, the Queensland Government-owned generators Stanwell, CS Energy and CleanCo, and the Australian Government-owned Snowy Hydro are participants directly owned by governments. Each has a significant presence in the region(s) in which they operate (section 3.1.1).

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

Particular concerns were raised about Snowy Hydro's Snowy 2.0 project. It was argued the size of Snowy 2.0 would crowd out investment in NSW, other than large-scale solar, wind and batteries, for the foreseeable future. Concerns were also raised about the market power Snowy Hydro could possess once Snowy 2.0 was commissioned, given its already large flexible generation fleet (section 3.1.2).

Issues were also raised with the ability of governments to direct operational decisions of generators they own. In particular, it was argued the Queensland Government's directions to Stanwell Corporation, in effect from 2017 to 2019, had significant ongoing impact on the market. Not only did the directions distort market signals while they were in effect, they also created a perception that such directions may be re-imposed at some point in the future. This may limit the effectiveness of price signals as a driver of investment decisions in the medium to longer term.

7.1.7 Government interventions to underwrite investment can impede market efficiency

Stakeholders pointed out that even if governments do not directly invest in generation assets, schemes to underwrite generation investment potentially impedes market efficiency.

The Victorian Government's Renewable Energy Target (VRET), the Queensland Government's Renewable Energy Target (QRET), the ACT 100% Renewable Energy Target, and the Australian Government's Underwriting New Generation Investments (UNGI) schemes were cited as examples of governments intervention to underwrite investment.[89 90 91 92] The NSW Government's recently announced Electricity Infrastructure Roadmap also proposes significant underwriting of future generation investment.[93]

Governments have intervened in the absence of the market delivering new investments. While some stakeholders highlighted that government interventions are one of the factors which may have impacted investment, others argued that it is not clear that investment would have occurred under the current market design without government support.

88 Part XICA into the *Competition and Consumer Act 2010* (CCA) inserted by the Treasury Laws Amendment (Prohibiting Energy Market Misconduct) Act 2019 (PEMM Act). For more detail, see ACCC, *Electricity market misconduct*, ACCC website.

89 Victoria State Government, *Victoria's renewable energy targets*, Department of Environment, Land, Water and Planning energy website.

90 Queensland Government, *Achieving our renewable energy targets*, Department of Resources website.

91 ACT Government, *100% Renewable Energy Target*, Environment, Planning and Sustainable Development Directorate website.

92 Australian Government, *Underwriting New Generation Investments program*, Department of Industry, Science, Energy and Resources energy website.

93 NSW Government, *Electricity Infrastructure Roadmap*, NSW Government energy website.

While stakeholders acknowledged the schemes are designed to meet environmental, affordability and/or reliability objectives, it was argued they potentially raise significant efficiency concerns. Stakeholders argued that by 'picking winners', government underwriting could potentially shape the generation mix the market would provide, rather than market signals. This could pose risks of locking in currently available technologies in an environment of increasingly dynamic technology change. Parties noted that underwriting might not deliver the mix of generation the market requires.

Stakeholders also highlighted that government decisions on generation investment could lead to inefficiencies, particularly through overinvestment. It was argued the risks are heightened where governments pursue other objectives, such as job creation, as part of their investment decision making. Overinvestment could potentially encourage generators that might otherwise continue operating, to exit, which could lead to higher prices and other market issues. Inefficiencies would ultimately be borne by taxpayers.

It was noted the scale of underwriting currently proposed has the potential to fundamentally change market dynamics. It was felt that market investment would increasingly be driven not by market signals, but by responding to government incentives. This was considered to be a fundamental change to how the NEM operated to date.

7.2 Impacts of barriers to entry and market impediments

Barriers to entry and market impediments affect all potential investment to some extent. However, it is difficult to accurately assess what impact these barriers may be having.

There are prevailing structural characteristics of the market that will act as a barrier to entry, particularly for some generation technologies. High-cost, long-term generation investments have inherent risks and challenges—for example generation that requires initial large fixed costs which cannot be recovered if entry is unsuccessful. The risks of these investments becoming stranded are higher in an environment of significant technological change and supply and demand uncertainty. These characteristics would have major impacts on entry and expansion, even if the other barriers we have highlighted were not present.

There has been significant investment in new wind and large-scale solar generation and more recently in batteries, and there is more on the horizon (section 6.1). This suggests barriers to entry for those technologies have not been significant enough to deter investment. The modular nature of wind and large-scale 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 in sustained investment.

Much of that investment, however, was supported by Australian and state government renewable energy target schemes. Therefore, although our analysis in section 6.2 shows sustained market signals for investment, it is difficult to determine how much investment would have occurred in the absence of these schemes.

For other technologies, the impacts of barriers to entry and market impediments are even more difficult to assess. For example our analysis has identified that although a price signal has been sustained for combined cycle gas turbines (CCGT) for a number of years, there has not been new entry (section 6.3). High-cost, long-term generation projects are inherently risky in an environment of future uncertainty. The existing market design and reliance on short-term price signals may not deliver significant investment in these generation types at the current time.[94] This seems to be a key driver behind increased government intervention to ensure major projects are built. However, uncertainty created by government intervention can also create barriers and make future market-driven investment in high cost, long term generation investments even more challenging.

In this environment, it will be important to monitor trends in generation investment (and the arrangements that support this investment).

94 These issues are being explored in the Resource Adequacy Mechanisms workstream of the NEM 2025 review.

8. Are the frequency control ancillary services markets competitive?

Key points

- The costs of maintaining the frequency of the system have increased as the need for ancillary services has increased. As a result, participants are earning more from frequency control ancillary services (FCAS) than before.
- Recent new entry has reduced concentration in FCAS markets and resulted in an increase in lower priced offers. In some cases, newer technologies are displacing incumbent participants. However, outcomes in the energy market remain a major factor in how participants behave in FCAS markets.
- The potential for participants to exercise market power still exists within local FCAS markets. In South Australia, competition has improved with new entry, but generator rebidding and a lack of low priced capacity contributed to recent high price events.

To safely function, the power system must balance the supply of electricity with demand at all times to maintain frequency within a narrow band of around 50 Hertz (Hz). The Australian Energy Market Operator (AEMO) uses FCAS to maintain this frequency. It can increase generation (or reduce load) to raise frequency, or decrease generation (or increase load) to lower frequency (box 8.1).

Similar to the energy market, participants offer into the 8 FCAS markets, and are paid for their services. And like energy, this process means that how markets are structured, and how participants behave in those markets can impact effective competition.

This chapter explores the competitiveness of FCAS markets in recent years:

- Section 8.1 highlights that the costs of maintaining system frequency have increased in recent years.
- Section 8.2 details the structure of FCAS markets and how new entry is changing this structure.
- Section 8.3 explores how participants' offers into FCAS markets have changed over the last 5 years and identifies some key drivers of this change.
- Section 8.4 discusses how local markets for FCAS are vulnerable to the exercise of market power.
- Section 8.5 looks at which participants earn revenue from FCAS markets.
- Section 8.6 examines future prospects for FCAS markets.

Many recent FCAS developments occurred in South Australia, so there is a strong focus on South Australian issues in this chapter.

Box 8.1 What is FCAS?

There are 2 general categories of FCAS: regulation and contingency. Regulation services continuously adjust to small changes in demand or supply that cause the frequency to move by only a small amount. Contingency services manage large changes in demand or supply that occur relatively rarely and move the frequency by a large amount.

In total, the Australian Energy Market Operator (AEMO) dispatches services in 8 FCAS markets to maintain system frequency at close to 50 Hz:

- Raise and lower regulation services
- Raise and lower 6 second contingency
- Raise and lower 60 second contingency
- Raise and lower 5 minute contingency

Costs are recovered from participants that contribute to deviations in frequency.

FCAS can refer to global or local requirements:

- The majority of the time, FCAS can be shared over interconnectors between all regions. In these times we consider the markets for FCAS to be global. When we refer to global offers we are describing offers from participants in all regions which can be used to meet global requirements.
- If there is a credible risk of at least one region separating from the rest of the National Electricity Market (NEM), such as from the potential loss of an interconnector, local FCAS requirements can be established. Local requirements ensure that should separation occur, each region remains stable. At these times FCAS requirements can only be met by participants in the local region. This is typically an issue for regions at the extremities of the grid (Queensland, South Australia and Tasmania).

Due to the complexities in providing FCAS, there are a number of levels of granularity with which it can be examined. We use the following in this section:

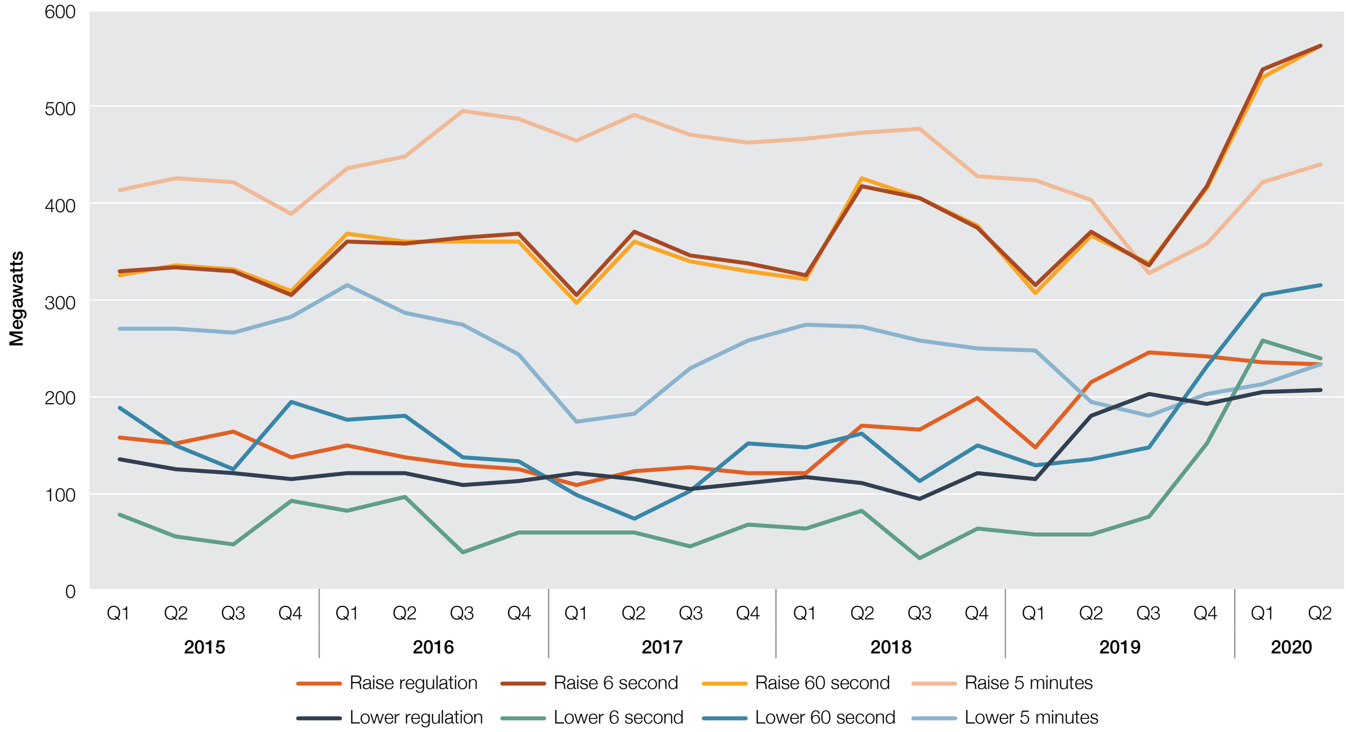
- Registered capacity—the maximum amount registered to provide FCAS
- Maximum availability—the maximum amount offered into the markets by participants
- Effective availability—the amount of FCAS on offer that can be dispatched, accounting for trade-offs between FCAS supply and electricity generation
- Enablement—the volume of FCAS actually dispatched.

AEMO's procurement of each FCAS service (in megawatts) depends on a number of constantly varying factors. For contingency services, AEMO procures an amount equal to the size of the largest credible contingency event minus assumed load relief. For regulation services, AEMO sets a minimum procurement, which it continually adjusts depending on other system requirements.

8.1 The costs of maintaining the frequency of the system have increased

From January 2015 to June 2020 prices and costs for FCAS increased significantly (section 2.6). While changes in generator offer prices contributed to these increases, especially in 2016, rising requirements for each service played a significant part from 2019 (figure 8.1). AEMO's reasons to increase requirements were based upon improving frequency control (section 8.3.3).

Figure 8.1 Quarterly average global enablement for each FCAS market



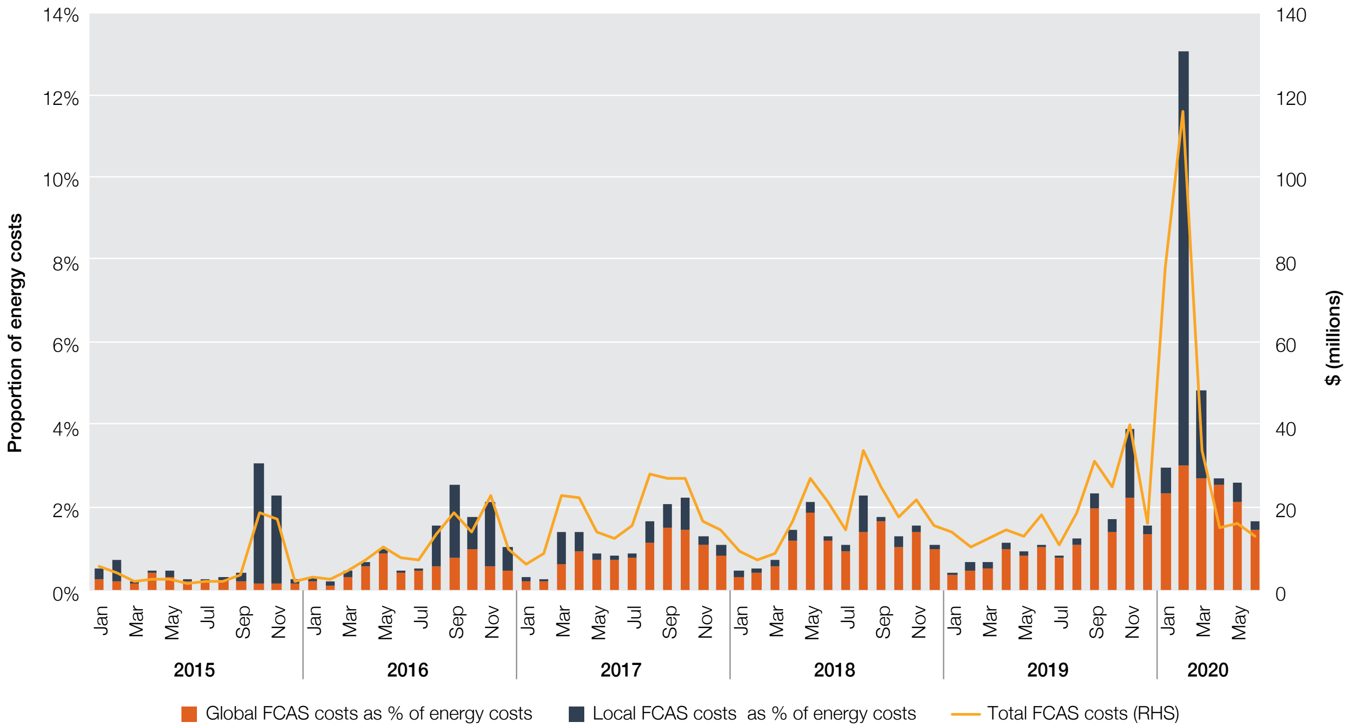
Source: AER analysis using NEM data.

Note: Global enablement represents the target (in megawatts) of all units providing the service, averaged for each quarter.

Overall, regulation services contribute more than contingency services to total costs. And raise contingency services contribute far more than lower services, reflecting higher requirements for raise services.

While FCAS costs as a proportion of total energy costs are relatively small, they are increasing (figure 8.2). In some recent months global FCAS costs were around 3% of energy costs. Local FCAS costs are highly dependent on region-specific issues. Over the past 5 years, the majority of those costs occurred in South Australia, where significant local requirements to procure FCAS combined with low levels of competition.

Figure 8.2 FCAS costs as a proportion of energy cost



Source: AER analysis using NEM data.

Note: FCAS costs are the sum of total costs for each ancillary service for the NEM, calculated by multiplying the regional price with the regional dispatch of each service for all regions. This has then been split in to Global and Local costs. 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 2. Native demand is the sum of initial supply and total intermittent generation in a region.

Monthly total FCAS costs increased from around $3 million in early 2015 to $40 million in late 2019. Exceptionally high costs in early 2020 were driven by a range of extreme events, including high temperatures and bushfires. South Australia also experienced multiple interruptions on the Heywood interconnector, which meant it was separated from the rest of the National Electricity Market (NEM) for more than 2 weeks in early February and March 2020. This separation accounted for the majority of local costs at this time.[95]

8.2 New entry has reduced concentration in FCAS markets

Up to 8,785 megawatts (MW) of registered FCAS capacity is offered by a range of participants (figure 8.3).[96] But not all of that capacity is always on offer, and only a small portion of it is 'effectively' able to meet the dynamic requirements of FCAS. This is because of trade-offs between the provision of energy and FCAS (box 8.2). In 2019–20, average effective availability was between 7% and 32% of registered capacity, depending on the market. When there is low effective availability, FCAS markets can easily be uncompetitive because only one or very few participants may be able to provide a service in specific conditions.

95 AER, *Wholesale markets quarterly—Q2 2020*, 14 August 2020, p. 25.

96 As at 30 June 2020, there was a significant amount of capacity across the NEM registered to provide FCAS. For contingency services: 8785 MW (lower 5 minute), 7652 MW (lower 60 second), 3564 MW (lower 6 second), 7373 MW (raise 5 minute), 8502 MW (raise 60 second), 5248 MW (raise 6 second) and for regulation services: 7945 MW (lower) and 7977 MW (raise).

Box 8.2 Trade-off between energy and FCAS provision

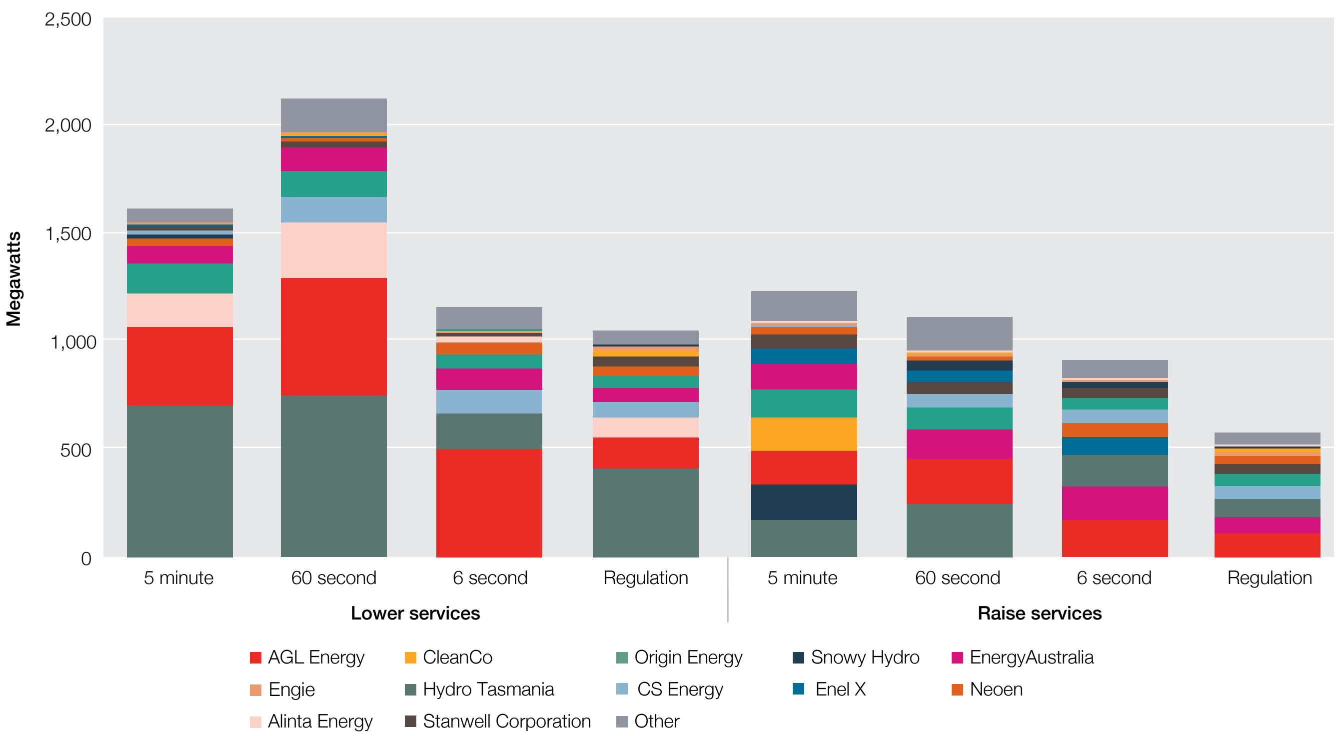
To minimise overall costs, AEMO co-optimises offers and requirements in energy and FCAS markets simultaneously.

As in energy, participants offer into FCAS markets across 10 price bands. For most participants, a generator must be actively providing energy in order to provide FCAS, by raising or lowering generation output. But the degree to which a participant is dispatched in the energy market impacts the amount of FCAS it is able to provide. If a participant is already generating energy at its maximum capacity, it could not further increase generation to provide raise FCAS so, despite its offers, its 'effective' availability for raise services would be 0 megawatts (MW). If a participant is generating at its minimum, it could not decrease its generation to provide lower FCAS, so its effective availability for lower services would be 0 MW.

Technologies such as batteries and hydro generators are capable of providing FCAS without providing energy at the same time. This makes them flexible and effective in responding to signals in FCAS markets.

FCAS market shares indicate there is more competitive pressure in the market than there was 5 years ago. Over this time, new entry from demand response aggregators such as Enel X Australia and Energy Locals, and participants with batteries such as Neoen and Infigen Energy, have increased the number of players in FCAS markets and reduced market concentration. This change is most significant in raise markets where new participants accounted for up to 17% of effectively available capacity in 2019–20 for raise 6 second services.

Figure 8.3 Market share by average effective availability 2019–20



Source: AER analysis using NEM data.

Note: Average effective availability for all participants registered to provide FCAS for the period from 1 November 2019 to 30 June 2020. This time period accounts for the period from the establishment of CleanCo.

The vast majority of the time, FCAS markets operate as a global market and participants providing FCAS compete across all regions of the NEM. But if interconnectors become constrained or regions become islanded, the ability to transfer FCAS between regions is limited and local markets emerge. In these cases, the risk of inefficient and uncompetitive outcomes increases.

Regions located at the edges of the grid, namely Queensland, Tasmania and South Australia, are more likely to form local markets, requiring FCAS needs to only be met by participants within that region. When these regions are considered individually, market concentration increases significantly:

- Queensland has 7 providers of FCAS, but CS Energy, Stanwell Corporation and CleanCo collectively controlled 91% to 100% of effectively available capacity in 2019–20 across all FCAS markets.[97]
- South Australia has 7 providers of FCAS, but AGL Energy and Neoen collectively controlled between 62% and 85% of effectively available capacity in 2019–20, across all FCAS markets.
- In Tasmania, as in energy, Hydro Tasmania controls all FCAS capacity.

High levels of concentration make these markets susceptible to the exercise of market power.

8.3 FCAS offers largely depend on dynamics in the energy market

Global participant offers in FCAS markets have broadly followed similar trends to those in energy. Prior to 2016, there was a significant amount of low priced capacity offered and prices were low and stable. In 2016, a number of factors, including an extended outage of the Basslink interconnector, motivated participants to increase the price of their offers. Offers generally remained elevated until around 2018, when some new entrants began offering FCAS in various markets at low prices, which encouraged incumbents to lower offer prices to compete.

However, the benefit of new entry was not realised immediately in all markets, as operational changes by AEMO meant the amount of FCAS required increased at a rate greater than the volume of low priced capacity. But more recently, prices have fallen across FCAS markets as participants make more capacity available at lower prices.

FCAS markets typically operate as global markets. That is, participants across the NEM may provide FCAS in a single market across interconnectors. This section explores changes that have occurred in how participants offer into global markets. However, in some cases a region may be at risk of separating, or electrically isolated, from the rest of the NEM. In those cases, a local market for FCAS is established to ensure that the energy supply remains stable in that region. Section 8.4 examines some issues that arise when local markets are established.

Importantly, in describing changes in capacity we typically refer to maximum available capacity. Due to trade-offs between providing energy and FCAS, what is effectively available is often much less than this amount. But, as effective offers are a portion of maximum offers, the trends in effective offers are much the same.

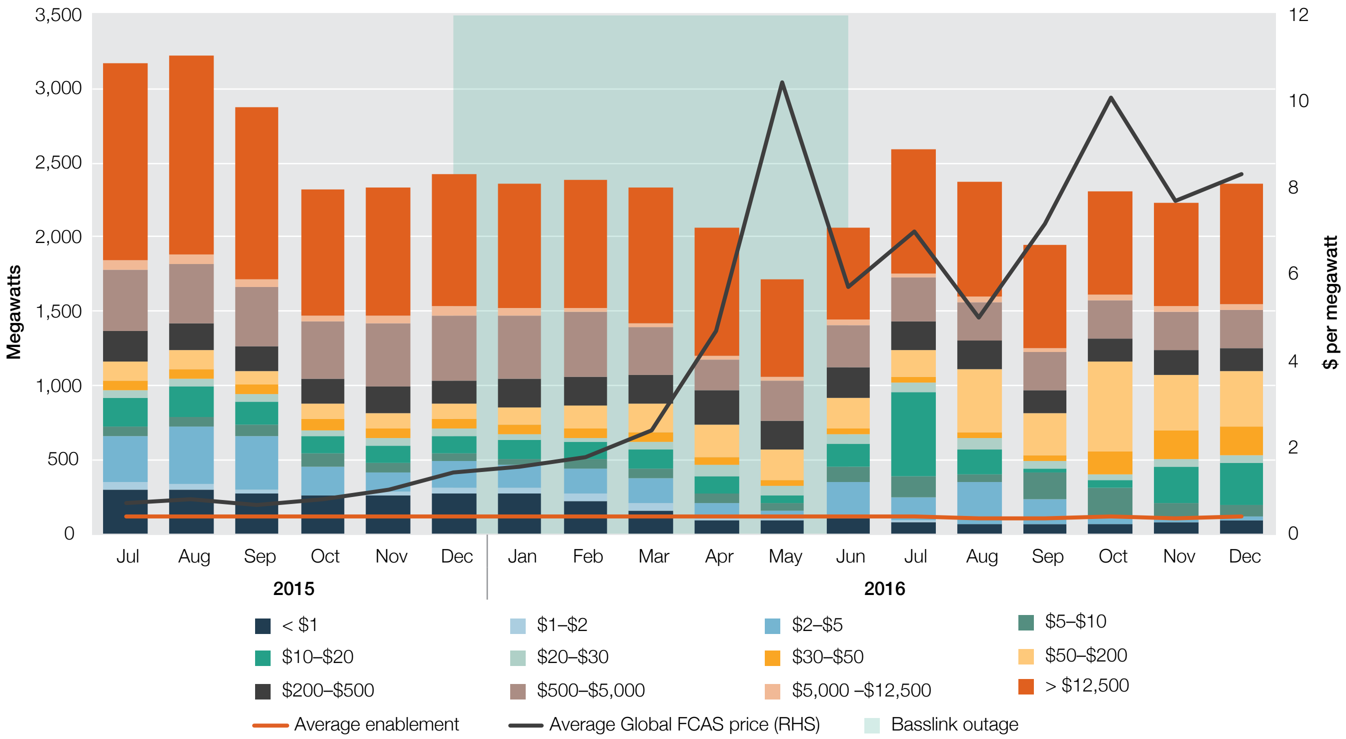
8.3.1 Participants shifted offers to higher prices in 2016

Across the different FCAS markets offers were generally stable in 2015, with significant low priced capacity on offer. FCAS was historically regarded as a by-product of energy, and so the FCAS markets saw limited activity. Monthly average prices in all markets were $2 per MW or less.

However, participants began shifting FCAS offers to higher price bands in 2016. In lower regulation services for example, participants shifted around 350 MW of capacity from prices below $10 per MW to higher prices from December 2015 to December 2016, or withdrew it from the market altogether (figure 8.4). With less low priced capacity on offer, this change significantly affected prices. We observed similar trends across other FCAS markets.

97 In this instance, 2019–20 refers to the period from 1 November 2019 to 30 June 2020 to capture the period after ownership of generation assets was transferred from Stanwell and CS Energy to CleanCo.

Figure 8.4 Lower regulation maximum availability 2015–16



Source: AER analysis using NEM data.

Note: Global quarterly average maximum availability in the lower regulation FCAS market, within price bands.

A number of factors influenced this change in 2016, including:

- Basslink experienced an extended outage lasting the first half of 2016. With Tasmanian generation unable to export across the interconnector, mainland generators had to increase output to cover the loss, leaving less effective generation available to provide FCAS. With less effective generation available, small changes in volumes offered could significantly impact prices.
- At the same time, price volatility and rising fuel costs for generation impacted energy prices in some regions. In response, participants shifted FCAS offers to higher prices, reflecting a change in the opportunity cost of providing FCAS. This is because a MW provided in FCAS is a MW foregone in energy. So, if the price of energy increases, the opportunity cost of supplying capacity for FCAS instead is greater.
- A small number of participants had been offering the majority of low priced FCAS. When those participants started changing their offer prices, no alternative source of low priced capacity was available, so higher-priced offers were needed to meet FCAS requirements. While other participants were providing more FCAS, it was at higher prices than before. For example, 73% of raise regulation FCAS was provided by 5 coal-fired power stations in January 2016. By December 2016 the same 5 generators only provided 38% of raise regulation FCAS. Over this time, the monthly average price of this service rose from under $2 per MW in January 2016 to over $12 per MW in December 2016.

8.3.2 New entry has provided some competition and lower priced offers

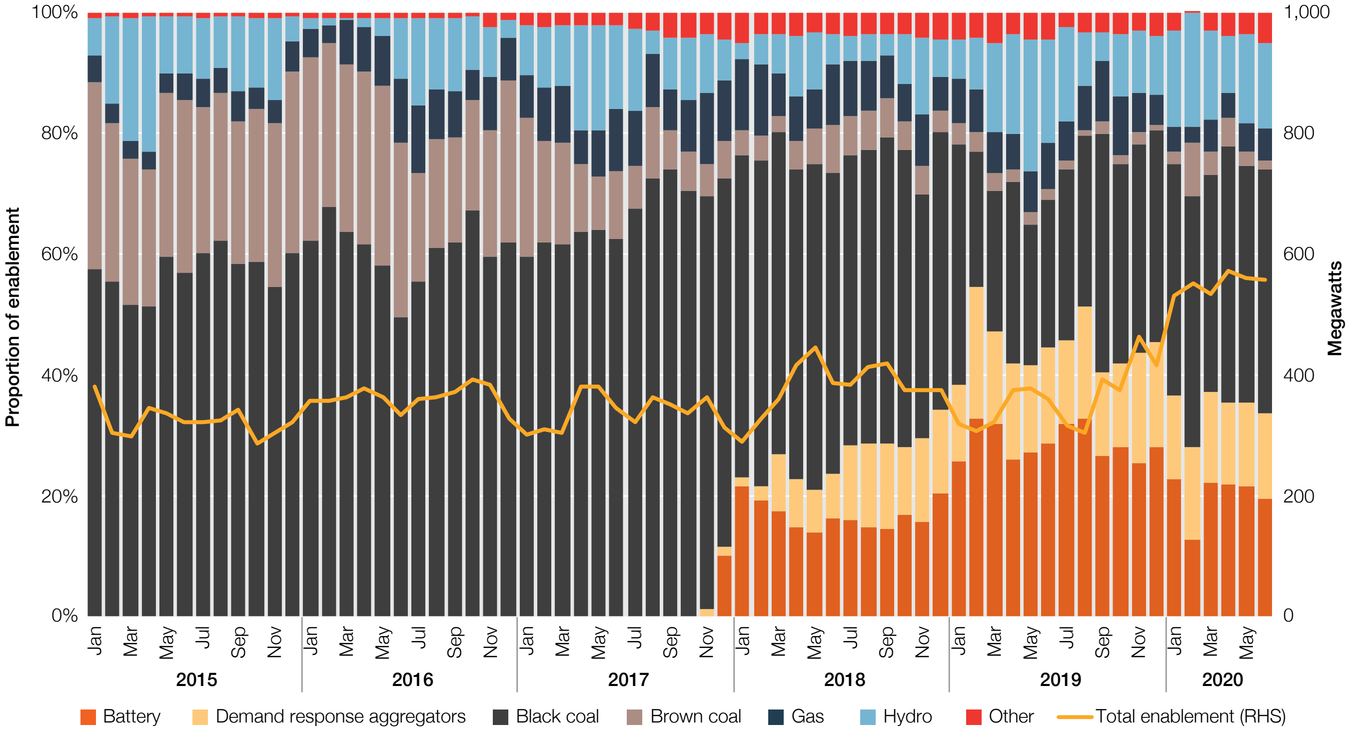
As in energy, higher priced FCAS offers persisted across 2017 and into 2018. Despite individual differences between markets, many FCAS markets saw prices peak in 2017 before easing in early 2018.

In late 2017, and early 2018 new entrant battery and demand response aggregator (DRA) participants entered FCAS markets. Notably, those participants were of a different technology type than incumbent providers and benefitted from different efficiencies. Batteries and DRA in particular differ from traditional providers of FCAS like coal or gas generators, in that they can provide FCAS without needing to provide energy as well. This makes them flexible and responsive. Batteries, for example, are generally more enabled in the 6 second contingency markets than other FCAS markets.

Importantly, the efficiencies inherent in those technologies allowed them to offer at mostly low prices. As a result, they were dispatched for the majority of what they offered. This new entry was competing from the bottom-up. This in turn encouraged some incumbent participants, such as black coal generators, to shift some capacity to lower prices to compete.

Ultimately, new entry improved the competitive landscape. The new participants successfully displaced some incumbent providers (black coal in particular), which resulted in lower priced offers (figure 8.5).

Figure 8.5 Raise 6 second service enablement by fuel type



Source: AER analysis using NEM data.

Note: Enablement is monthly average of all units raise 6 second target grouped by fuel type. Total enablement represents the target (megawatts) of all units providing the service, averaged for each month.

The benefits of new entry were most apparent in the raise and lower 6 second markets. However, other FCAS markets also saw increases in lower priced offers.

New entry has continued. In the first half of 2020, battery and demand response participants were enabled for between 120 and 190 MW on average in raise contingency markets, and between 30 and 80 MW in other markets.

8.3.3 AEMO increased FCAS requirements, prolonging higher prices

Despite increased competition encouraging lower priced offers, some markets experienced higher prices into 2019. In regulation markets in particular, prices continued to rise due to AEMO increasing the amount of FCAS required.

From March 2019, AEMO increased its procurement of regulation services by 50 MW across the mainland to improve frequency performance.[98] [99] Its action responded to concerns of weakening power system frequency control due to changing system conditions (including extreme weather), generation volatility, an increase in load, and an overall reduction in the amount of regulation services procured.

Separately, from September to December 2019, AEMO began to progressively reduce the level of assumed load relief on the mainland after a review of contingency FCAS requirements.[100] To balance this, AEMO progressively increased the amount of contingency FCAS enabled.[101] [102] However, in some markets the increases in the amount of FCAS required offset the additional cheap capacity that new participants had made available. So, prices continued to rise for some services (figure 8.6). In late 2020, AEMO began similar adjustments in Tasmania.[103]

98 The changes followed a trial where AEMO increased the baseline of regulation FCAS by 30 MW which ran across October and November 2018.

99 AEMO, *Regulation FCAS changes* [PDF 140KB], fact sheet, 2019.

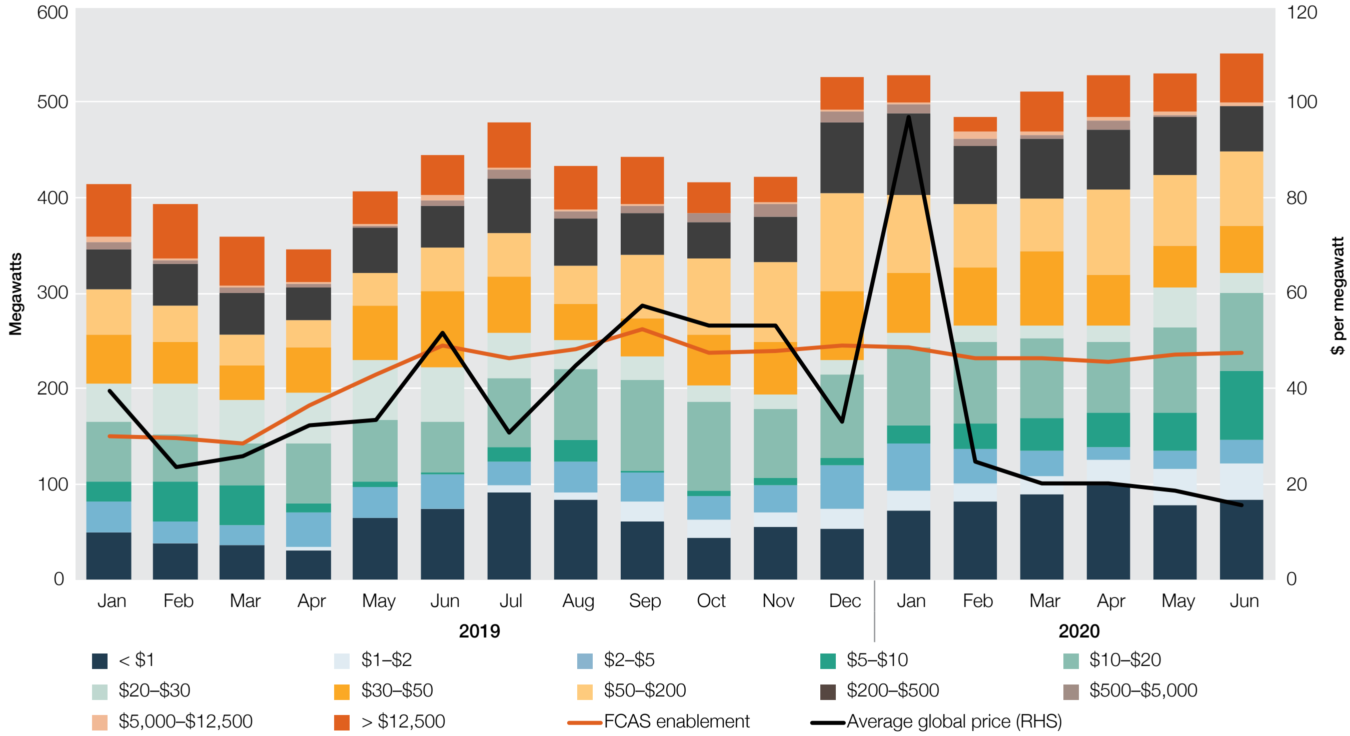
100 Load relief is an assumed change in load from induction machines (traditional motors, pumps and fans) that occurs when power system frequency changes. This type of load draws less power when frequency is low and more power when frequency is high)

101 AEMO, *Frequency Control Work Plan*, 25 September 2020.

102 AEMO, *Update on contingency FCAS November 2019*, 19 November 2019.

103 AEMO, *Load relief*, AEMO website.

Figure 8.6 Raise regulation effective offers and requirement 2019–20



Source: AER analysis using NEM data.

Note: Global quarterly average maximum availability in the raise regulation FCAS market, within price bands.

More recently, prices eased in FCAS markets as participants shifted higher priced capacity to lower prices. This coincided with lower energy and fuel prices, and further new entrants driving competition.

A price spike in Q1 2020 stands separate from the overall trend. Due to an outage on the Heywood interconnector between South Australia and Victoria, South Australia was electrically isolated from the rest of the NEM for over 2 weeks and needed to provide its own FCAS. During this period, costs were high as prices and the amount of FCAS required fluctuated in response to the outage and other extreme conditions.[104]

8.4 While the competitive landscape for local FCAS in South Australia has improved, the region remains vulnerable to the exercise of market power

As identified in section 8.2, local FCAS markets remain relatively concentrated, making them vulnerable to exercises of market power and inefficient outcomes. In particular, we have observed these outcomes in South Australia. In Queensland and Tasmania—other regions where local markets are most likely to form—market power issues have been less apparent over the past 5 years.

Both Queensland and Tasmanian FCAS markets are dominated by government-owned corporations, which hold significant market power. As those participants are government-owned, they are subject to government direction and regional regulation, which may create a different set of incentives regarding the exercise of market power (section 3.5.2). Despite less FCAS price volatility in those regions over the past 5 years, issues occurred in the past. For example, in 2010 the Office of the Tasmanian Economic Regulator issued a price determination regarding Hydro Tasmania's provision of raise contingency FCAS following a period of price volatility in those markets. The determination ended in early 2016, and the previously observed volatility has not returned.

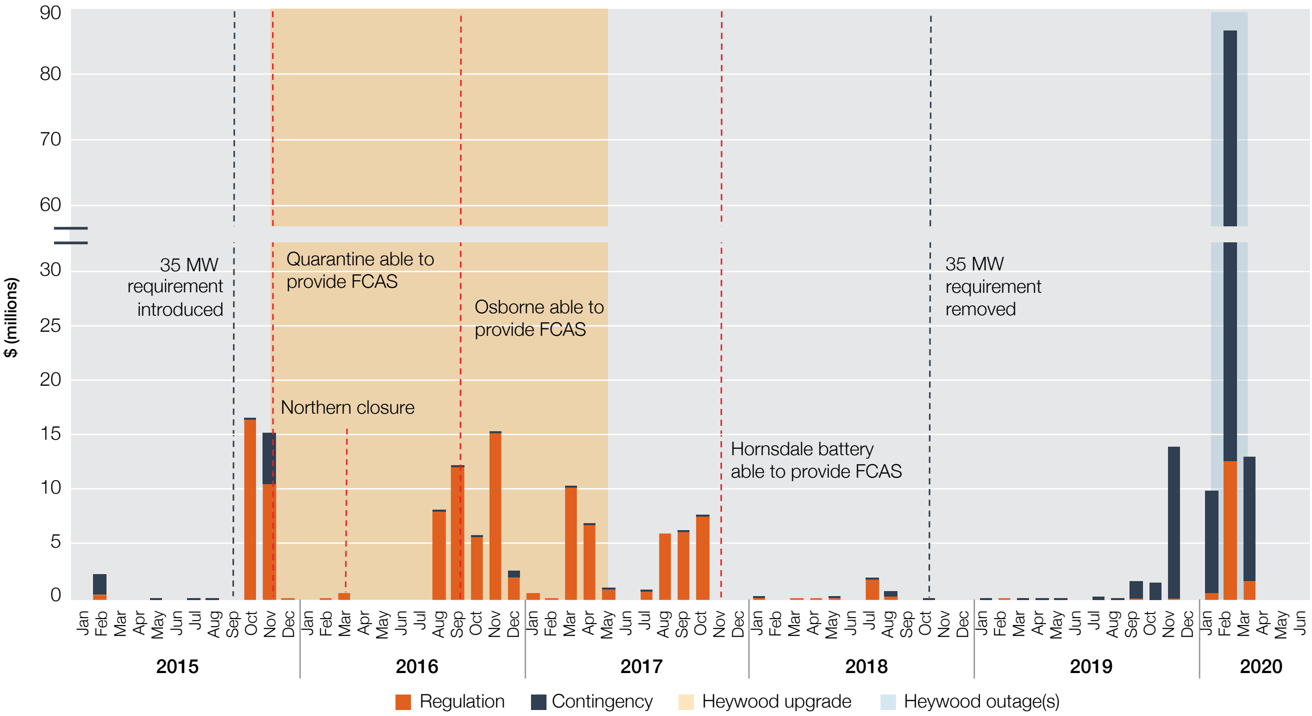
In our last report, we discussed past issues in South Australia's local FCAS markets. In particular we highlighted how costs increased after AEMO introduced a 35 MW local regulation FCAS requirement in the region in October 2015. This coincided with the commencement of an upgrade to the Heywood interconnector, which meant the local requirement was frequently invoked as the interconnector experienced partial outages.

104 For more detail, see our *Wholesale markets quarterly—Q1 2020* and *Wholesale markets quarterly—Q2 2020*.

At the time, the local market was highly concentrated as few participants could provide FCAS. Once AEMO introduced the local requirement, participants drew on knowledge of their competitors previous availability to structure bids so there was collectively less than 35 MW available at low prices. If there was adequate low priced capacity when an unexpected event occurred, participants would often rebid from low to high prices across the day, such that less than 35 MW of capacity was available at low prices. Either way, limited supply meant that high priced capacity was needed, resulting in a number of high price events. Following several such events, Origin Energy entered the South Australian FCAS market. However, Alinta Energy's Northern power station closed soon after, withdrawing a significant FCAS supplier. High price events continued, and contributed to increased local FCAS costs (figure 8.7).

The Heywood upgrade was completed in March 2017, meaning the 35 MW requirement was invoked less often, but high price events continued to occur. However, the entry of new participants including Neoen's Hornsdale Power Reserve in December 2017 and the Hornsdale wind farm in March 2018 increased the number of participants supplying FCAS in South Australia, which coincided with a reduction in the number of high price events. From October 2015 to December 2017 there were 19 high priced events in regulation services. From December 2017 to October 2018 there was a single high price event. AEMO removed the 35 MW requirement in October 2018.

Figure 8.7 FCAS costs and events in South Australia



Source: AER analysis using NEM data.

Note: FCAS costs in South Australia from January 2015 to 30 June 2020. Heywood interconnector upgrade from October 2015 to April 2017. Q1 2020 Heywood interconnector outage from 31 January to 18 February 2020, and again on 2 March 2020.

A number of other participants have since entered to provide FCAS in South Australia, including other batteries and DRA. While new entry has been positive for competition, issues can still arise if there is a local requirement. Since AEMO removed the 35 MW requirement in October 2018, there have been 6 high price events in FCAS in South Australia, across a number of markets.[105] All occurred during an outage, or potential outage of the Heywood interconnector—2 in November 2019, and 4 from January to March 2020.

For the November 2019 events, high prices eventuated as the requirement was greater than the amount of low priced capacity available.[106] For the 4 events in early 2020, a number of factors contributed to high prices across all markets. Importantly both a lack of low priced capacity and participant rebidding were significant factors in some of the high prices that eventuated. In some cases, a single participant was able to rebid capacity to the price cap, and without

105 Here, high priced events refers to instances when the price for FCAS was greater than $5,000 per MW, which are able to be grouped together due to shared causes. For example, on 2 March 2020, FCAS prices were greater than $5,000 per MW for a number of trading intervals across all markets, however the underlying cause is the same. So, we group these as a single "event". We analyse these events in more detail in our *Wholesale markets quarterly—Q2 2020*, pp. 28–34.

106 The high prices for these events were in lower 60 second and lower 6 second services on 9 November 2019, and lower and raise 6 second services on 16 November 2019.

sufficient alternatives available the price was set at that level. This contributed to record costs in Q1 2020, which may have been higher except for the application of an administered price cap.[107]

Further new entry may improve outcomes by increasing the amount of low priced capacity available. Improved competition would assist with limiting the transient market power that allows a participant to rebid and still be dispatched, resulting in high prices. But until there is more capacity and greater competitive pressure in South Australia, the risk of non-competitive outcomes in the local market remains. Importantly, these same risks also exist for Queensland and Tasmania.

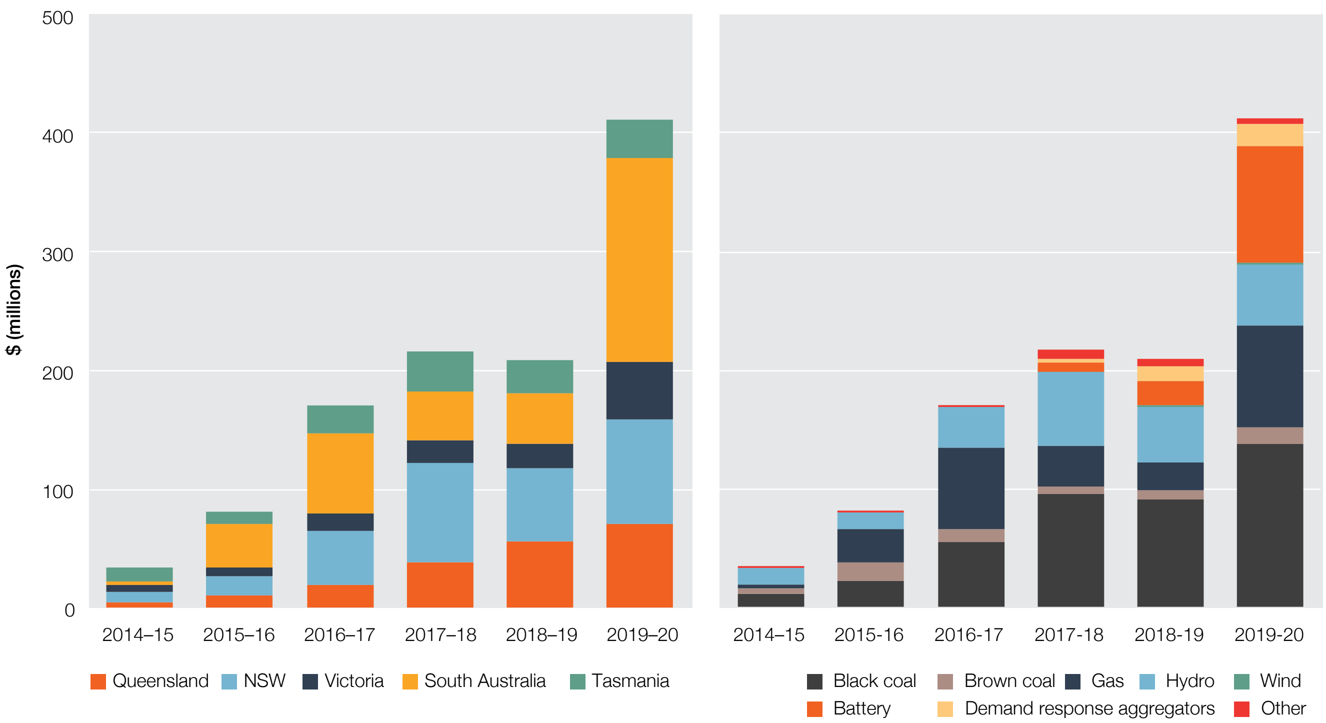
8.5 As FCAS prices increased, so too did participants' revenue

As FCAS costs have increased, so too has the revenue to be made from providing those services. While estimates of an individual participant's costs and profits from providing FCAS are complex, we examined the gross spot revenue participants made over the past 5 years.[108]

8.5.1 There is more money to be made from providing FCAS than before

Since 2015, FCAS revenue gradually increased as participants shifted offers into higher price bands (figure 8.8). Revenue levelled off briefly in 2017–18 and 2018–19, but in 2019–20, participants made about 10 times more revenue than in 2014–15. While 2019–20 results are skewed by the revenues accrued during South Australia's electrical isolation from the rest of the NEM, AEMO continued to increase the amount of FCAS required from 2019, peaking in early 2020. So despite recent price falls, requirements for more FCAS mean participants' revenues from FCAS are likely to keep rising.

Figure 8.8 Total FCAS revenue by region and fuel type



Source: AER analysis using NEM data.

Note: Revenue was determined by multiplying each unit's 5 minute dispatch target by the FCAS price, then divided by 12 (to express in $ per MWh). Each unit's revenue was then grouped up to the regional level or by fuel type.

Over recent years, there has been a shift in the mix of participants earning revenue from FCAS markets. In 2014–15, the majority of FCAS revenue was earned by Hydro Tasmania and black coal generators in NSW. In later years, black coal participants increased their earnings, and South Australian gas generators began to earn more as AEMO mandated local requirements, coupled with a lack of competition, caused price volatility. More recently, Queensland

107 Under the National Electricity Rules (Clause 3.14), if the sum of the preceding 7 days' prices (the previous 2016 dispatch intervals) exceeds 6 times the cumulative price threshold for any FCAS market, then an administered price cap of $300 per MW is applied to all FCAS markets. Administered pricing remains in place until the sum of the uncapped prices falls back below this threshold.

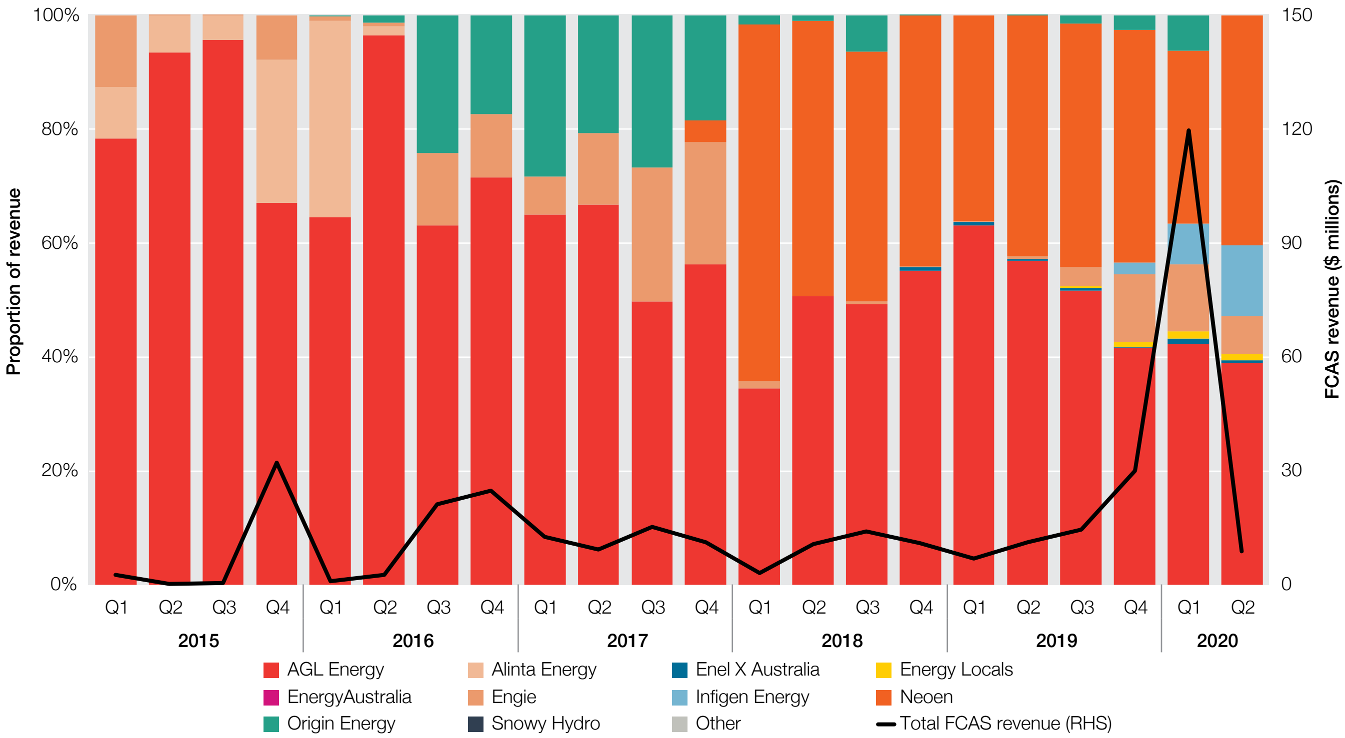
108 This analysis multiplies the monthly FCAS enablement at a station level with price and is indicative of gross earnings. There are other factors that influence the net profit participants earn, including contract positions and causer-pays contributions, which we have not included.

black coal generators have earned more from FCAS. But in 2019–20, South Australian FCAS participants made the most money, with gas generators and the newer battery and DRA technologies earning significant revenue during the extended outage on the Heywood interconnector.

8.5.2 New entrants displaced incumbent earnings in South Australia

As discussed in section 8.4, local FCAS events in South Australia highlight issues with competition in the region. Historically, only a few thermal participants were able to provide FCAS in South Australia—Alinta Energy (Northern power station), Engie (Pelican Point power station) and AGL Energy (Torrens Island power station). Generally, AGL Energy earned the highest FCAS revenues (figure 8.9). Those revenues were modest until late 2015 when AEMO introduced the 35 MW regulation requirement for South Australia.

Figure 8.9 Proportion of total FCAS revenue earned by each participant in South Australia



Source: AER analysis using NEM data.

Note: Revenue was determined by multiplying each unit's 5 minute dispatch target by the FCAS price, then divided by 12 (to express in $ per MWh). Each unit's revenue was then grouped by ownership. Ownership determined using ownership declared to AEMO for each unit. Where an intermediary operates on behalf of the owner, that capacity is attributed to the intermediary.

Initially, the market responded to prices increasing in 2016, with Origin Energy registering its Osborne and Quarantine power stations. But after Northern power station closed in May 2016, revenues were shared between AGL Energy, Origin Energy and Engie until December 2017.

The competitive landscape changed when the Hornsdale Power Reserve entered the market in December 2017. Upon entry, it displaced the FCAS earnings of Origin Energy and Engie almost entirely, and its owner Neoen occasionally replaced AGL Energy as South Australia's highest FCAS revenue earner. While Neoen increased the concentration of revenue earned by the top 2 participants, it competed from the bottom-up. So, it generally offered in at lower prices than its competitors, and was dispatched for the majority of what it offered.

More recently, other batteries owned by AGL Energy and Infigen Energy entered the market and secured a portion of FCAS revenue. In our market enquiries, participants expressed concern that potential FCAS revenue could not sustain multiple batteries competing in the same markets at the same time. However, South Australia's experience suggests there is potentially room in the market for multiple batteries to earn revenue in FCAS markets. Additionally, demand side providers such as DRA and virtual power plants are starting to acquire a share of FCAS revenue. Those participants are currently much smaller in comparison, but as interest in demand side solutions grows, their revenue potential will grow.

8.6 FCAS market dynamics will continue to evolve as the market transitions

FCAS markets have experienced significant changes over the past 5 years. Prices have risen and fluctuated across this period. In our market enquiries, some participants suggested that FCAS has been historically undervalued (some high price events notwithstanding) and only after recent price rises are those services being valued appropriately.

As participation in the FCAS markets is voluntary, prices should act as signals for investment or new entry. While it may be unlikely for some technologies to enter the market on the basis of FCAS revenue alone, we have seen participants register for FCAS in response to changes in prices and conditions. For example, in 2016 after some high price events and AEMO's 35 MW regulation requirement, Origin Energy registered 2 generators to provide FCAS in South Australia. And, as discussed in section 8.3.2, new technology entrants have registered to provide FCAS. It appears those participants have been able to displace some market share of incumbents and secure a portion of the revenue available (section 8.4).

These new participants have challenged the initial market design, which was based around thermal generation. Batteries, for example, are highly flexible and precise, and can respond to changes in frequency within milliseconds. Currently, the market does not have a mechanism to reward this responsiveness. In addition, other ancillary services such as inertia are currently not rewarded. In July 2020, the Australian Energy Market Commission (AEMC) began consulting on rule change proposals, which if implemented would develop markets for the provision of fast frequency response and other system services.[109] Also, the Energy Security Board is working on a number of complementary market design initiatives as part of its *Post 2025 market design for the National Electricity Market* (NEM 2025) work, some of which relate to new mechanisms to value ancillary system services.[110]

The markets for ancillary services will continue to evolve as the energy market continues its transition. Initiatives to accommodate new technologies and innovation are important to ensure the efficient operation of the market. However, care must be taken to not overly prescribe changes in market rules. If new technologies and services are over-regulated it may stifle investment and innovation, causing more harm than benefit.

We will continue to monitor the competitiveness of FCAS markets. In particular, we will examine outcomes in local markets and seek to expand our analysis in future reports.

109 AEMC, *Fast frequency response market ancillary service—Consultation paper*, rule change, 2 July 2020.

110 ESB, *All about the post 2025 project*, ESB post 2025 market design website.

9. Where to from here?

Key points

- We identified aspects of the market we will analyse in more depth in the future. We will continue to monitor the performance of the wholesale market, focussing on how outcomes change across the day, how generators behave from a portfolio perspective, investment trends, and frequency control ancillary services (FCAS) markets.
- Our initial review of generator returns found that generators have made positive earnings in recent years, with the level varying significantly by technology. We aim to request information from participants to inform more detailed conclusions on generator earnings.
- The current review of market design will be critical in shaping the future direction of the market. This work also provides the opportunity to embed policies being implemented at the state level into a common National Electricity Market (NEM)-wide framework.

In this report we made a number of observations on competition and efficiency issues in the NEM. This chapter discusses our key findings, next steps for areas of future analysis, and highlights reform processes and other developments that could influence competition and efficiency going forward:

- Section 9.1 summarises the main findings in our assessment of the market.
- Section 9.2 explores where more analytical work would promote a better understanding of changing market dynamics.
- Section 9.3 outlines reforms that could impact competitive market dynamics.
- Section 9.4 considers future directions for the NEM.

9.1 Market performance has changed considerably since 2018

The performance of the NEM has changed considerably from when we reported in 2018. Across all regions, wholesale prices have fallen significantly from the levels seen 2 years ago. These falls largely reflect lower priced offers from participants in response to reductions in fuel input costs, and the entry of additional low cost supply.

Structurally, the market remains concentrated, despite the entry of new renewable generation marginally reducing concentration in some regions. A few large participants still control a significant portion of generation in each region. This leaves the market potentially vulnerable to the exercise of market power.

However, we have not identified a concerning exercise of market power by generators in this review. Importantly, we found that changes in input costs were reflected in generator offers. Further, rebidding was not a major driver of short-term price spikes. Market dynamics during the day are changing, as increased large-scale solar generation contributes to more negative prices in the middle of the day, while flexible generation is becoming more important in the evening. In certain circumstances and as more thermal generation exits the market, tighter supply demand conditions could make the market vulnerable to the exercise of market power.

But for some generators, the ability to earn significant revenues exists without needing to exercise market power. However, our initial modelling based on publicly available information suggests that earnings can vary over time and between generator fuel types depending on spot prices, costs and contracting strategies. We aim to request information from participants and explore earnings in more detail.

Our analysis shows that price signals exist for a range of generation and storage technologies to enter the market. In this environment, we will monitor whether an efficient response to emerging price signals occurs, or whether barriers to entry prevent or limit this response.

FCAS markets have experienced similar changes to those in the energy market. As prices rose in energy, participants shifted their FCAS offers to higher prices. More recently, as energy prices fell and new technologies have outcompeted incumbent participants, offers have come back down. Despite prices falling, the Australian Energy Market Operator (AEMO) is sourcing more FCAS from the markets, so participants are receiving higher revenues from FCAS than ever before.

9.2 Our review highlighted other areas where more work is required

We expanded our areas of focus in 2020 from our last report, and this current review highlights areas where we intend to undertake further work to better understand competition developments.

New intraday dynamics are emerging as the market transitions to one increasingly reliant on intermittent generation sources. Our analysis highlighted more frequent negative prices during the day and the increasing role flexible generation, particularly hydro, plays in setting prices during the evening peaks. With this set to continue, we intend to further analyse the impacts of increased intermittent generation during the day and how flexible generators respond during evening peaks.

Much of our assessment of competition is conducted on a regional basis. But many participants hold generation assets across multiple regions. Those participants typically optimise their production across the portfolio as a whole, rather than by region. Accordingly, we intend to consider how generators operate their portfolios across regions. This will require a more detailed assessment of participant offer behavior across regions and how this impacts interconnector flows.

In this report, we reviewed behaviour in contract markets in more detail than in 2018. However, this analysis is based on publicly available information, which constrains our ability to rigorously assess contract market dynamics. There is limited public information available on contracting arrangements in the NEM, with participants' trading positions considered commercially sensitive. The Australian Competition and Consumer Commission (ACCC) has recommended that the AER's wholesale market monitoring functions should be expanded and appropriately funded to include monitoring, analysing and reporting on the contract market.[111] We will continue to advocate for changes to allow us greater visibility over contract market outcomes.

In 2020 we undertook a review of generator earnings for the first time, based on publicly available revenue and cost information. While this work highlighted some interesting outcomes, it also revealed limitations of relying on publicly available information to make an assessment of this kind. We will request information from generators on actual revenues and costs to give a more accurate picture of generator returns.

We also analysed competition in FCAS markets for the first time, including basic metrics such as market shares. Given the increasing importance of FCAS, we propose to build on this assessment, and use a broader range of tools in future analysis. We will also seek to develop our understanding of how participants determine the cost of providing FCAS.

9.3 Other market changes and reform processes could affect competitive dynamics

A number of processes are underway on the broad challenges of ensuring electricity is provided reliably, securely and efficiently in a rapidly transforming energy sector.

A significant reform is the Energy Security Board's (ESB) *Post 2025 market design for the National Electricity Market* (NEM 2025).[112] The ESB is due to provide its advice to Energy Ministers on recommended changes to the market design by mid-2021.

NEM 2025 takes a holistic view of what needs to change to ensure the NEM can meet the future needs of consumers, including from intermittent generation, demand response, storage, and distributed energy resources. It identifies 7 market design initiatives (MDIs) to consider how electricity is generated and dispatched, how consumers can access the services they want, and how investment can occur in the most efficient way to avoid unnecessary costs.

Each MDI considers several options to address identified issues (table 9.1). Some reforms target issues highlighted in this report. For example, a range of potential reforms aim to ensure there is sufficient and timely investment in resources the market needs, be it from thermal and renewable sources, flexible capacity, energy storage of different types, and demand response resources. Further, transmission access reforms aim to address the growing issue of network congestion.

111 Recommendation 41. ACCC, *Retail electricity pricing inquiry—Final report*, 11 July 2018, p. 322.

112 ESB, *All about the post 2025 project*, ESB post 2025 market design website.

The reforms will potentially have significant impacts on how wholesale electricity markets operate. We will use our expertise to inform debates on these reforms as they are being developed. We will also closely monitor the impacts of these reforms on the operation of markets when they are introduced.

Table 9.1 NEM 2025 market design initiatives and potential reforms

NEM 2025 MARKET DESIGN INITIATIVES	POTENTIAL REFORMS
Resource Adequacy Mechanisms	Enhanced retailer reliability obligation Decentralised capacity market Operating reserve mechanism
Ageing Thermal Generation Strategy	Mechanisms to manage risks arising from exiting thermal generators
Essential System Services	Enhanced frequency control Introduction of missing essential services markets Spot markets for inertia and system strength
Scheduling and Ahead Mechanisms	Unit commitment Scheduling and services ahead market
Two-Sided Markets	Wholesale demand response mechanism
Valuing Demand Flexibility and Distributed Energy Resources Integration	Deep market integration for distributed energy resources
Transmission Access and the Coordination of Generation and Transmission	Actionable ISP Implementation of priority renewable energy zones Locational marginal pricing Financial transmission rights

Source: ESB, *Post 2025 Market Design Consultation Paper*, September 2020.

9.4 The market design is evolving to meet current challenges

Recent outcomes in the NEM and ongoing reform processes to address emerging challenges highlight some fundamental issues that the NEM now faces.

In the next 2 decades, generators that currently supply a significant proportion of NEM output are expected to exit the market. How that capacity will be replaced is a threshold issue. The current market design of the NEM is based on the premise that spot price trends provide signals for future investment in generation. As the capacity of available generation to meet demand diminishes, relative scarcity will lead to the dispatch of higher cost generators and increased spot prices, which should attract new capacity to enter the market. Contract markets can also underpin investment in the NEM by providing investors with a more stable and predictable revenue stream on which they can base future investment decisions.

Our analysis of the spot market shows a range of emerging price signals for investment. Recent investment has largely been in intermittent renewable technologies and batteries. Further investment in these technologies is already committed. However, for some other technologies we have not seen the investment that market signals suggest we should have.

Our review has highlighted a broad range of reasons why this investment may not have eventuated. Investment in capital intensive, long lived assets requires some confidence over future prices. The current spot market design and a contract market with little trading over 18 months out does not provide this confidence. In the absence of stable price signals the risk premium for delivering new investment will be higher (raising costs to customers) and investments are likely to be delayed or in smaller increments.

The rapidly changing market also makes investment challenging. We have highlighted that there is significant uncertainty about future technology costs, an unclear path for the exit of large generators, an uncertain outlook for energy-intensive industries which make up the majority of demand, significant concentration and a limited pool of creditworthy participants to contract with, and an increased use of directions due to a rapidly changing physical system.

The lack of investment in generation raises concerns among governments that the market may not deliver sufficient new generation in an acceptable timeframe. Policy objectives regarding the speed of transition to a low emissions energy system are also a factor. As a result, governments are increasingly driving investment in the market—through public sector investment in generation and by underwriting private investment.

This has a range of implications. The appetite for private investment is affected by the perceived risk of government intervention. But if private investment is not forthcoming, governments invest or intervene to fill forecast gaps, which in turn inhibits further private sector investment. Ultimately, this could lead to a situation where most generation is built, or at least supported, by government.

In this light, the ESB's NEM 2025 review will be critical in shaping the future direction of the market. Changes to market design being considered in this review are designed to address a range of the issues impacting investment we have highlighted, particularly issues around resource adequacy and ageing thermal generation exit strategies.

Further, recognising that governments will continue to pursue their policy objectives, to optimise efficiency as well as other objectives, it is desirable that there is a mechanism to embed these approaches in a common framework. Bringing specific schemes into a common NEM-wide framework will aid in the development of a co-ordinated, long-term reform path across the market.

In the current environment, this presents the best opportunity to promote future investment and efficiency, and secure the best outcomes for consumers.